EVOLUTION PETROLEUM CORP
Form 10-K
September 09, 2016

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K
ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended June 30, 2016
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.)

1155 Dairy Ashford Road, Suite 425, Houston, Texas 77079
(Address of principal executive offices and zip code)
(713) 935-0122
(Registrant's telephone number, including area code)
Securities registered pursuant to Section 12(b) of the Act:

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

Securities registered pursuant to Section 12(g) of the Act:
None
(Title of Class)
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes: o No: ý
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes: o No: ý
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes: ý No: o
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes: ý No: o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.
o

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

Large accelerated filer o Accelerated filer ý Non-accelerated filer o Smaller reporting company o
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act.). Yes: o   No: ý
The aggregate market value of the voting and non-voting common equity held by non-affiliates on December 31, 2015, the last business day of the registrant’s most recently completed second fiscal quarter, based on the closing price on that date of $4.81 on the NYSE MKT was $116,929,484.
The number of shares outstanding of the registrant's common stock, par value $0.001, as of September 7, 2016, was 32,905,982.
DOCUMENTS INCORPORATED BY REFERENCE
Portions of the proxy statement related to the registrant's 2016 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
2016 ANNUAL REPORT ON FORM 10-K
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This Form 10-K and the information referenced herein contain forward-looking statements within the meaning of the Private Securities Litigations Reform Act of 1995, Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. The words "plan," "expect," "project," "estimate," "assume," "believe," "anticipate," "intend," "budget," "forecast," "predict" and other similar expressions are intended to identify forward-looking statements. These statements appear in a number of places and include statements regarding our plans, beliefs or current expectations, including the plans, beliefs and expectations of our officers and directors. When considering any forward-looking statement, you should keep in mind the risk factors that could cause our actual results to differ materially from those contained in any forward-looking statement. Important factors that could cause actual results to differ materially from those in the forward-looking statements herein include the timing and extent of changes in commodity prices for oil and natural gas, operating risks and other risk factors as described in this Annual Report on Form 10-K as filed with the Securities and Exchange Commission ("SEC"). Furthermore, the assumptions that support our forward-looking statements are based upon information that is currently available and is subject to change. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages. All forward-looking statements attributable to Evolution Petroleum Corporation are expressly qualified in their entirety by this cautionary statement.

We use the terms, "EPM," "Company," "we," "us" and "our" to refer to Evolution Petroleum Corporation, and unless the context otherwise requires, its wholly-owned subsidiaries.

PART I

Item 1. Business

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

General

We are an independent oil and gas company engaged primarily in the acquisition, exploitation and development of properties for the production of crude oil and natural gas, onshore in the United States. We acquire known crude oil and natural gas resources and exploit them through the application of conventional and specialized technology, with the objective of increasing production, ultimate recoveries, or both. Additional information regarding our operating segment, major customers, revenues and assets can be found in in Item 8. Financial Statements - Notes to Consolidated Financial Statements.

Our petroleum operations began in September of 2003. On May 26, 2004, our predecessor, Natural Gas Systems, Inc. (Delaware, "Old NGS"), a private corporation formed in September 2003, merged into a wholly-owned subsidiary of Reality Interactive, Inc. (Nevada, "Reality"), an inactive public company, which was renamed Natural Gas Systems, Inc. ("NGS"). The former officers and directors of Reality resigned and the officers, directors and business operations of Old NGS became the Company. Concurrently with the listing of NGS shares on the NYSE MKT in July 2006, NGS was renamed Evolution Petroleum Corporation. Our principal executive offices are located at 1155 Dairy Ashford Road, Suite 425, Houston, Texas 77079, 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 common stock is traded on the NYSE MKT under the ticker symbol "EPM". We also have preferred stock which trades on the NYSE MKT under the symbol "EPM.A"

At June 30, 2016, we had six full-time employees, not including contract personnel and outsourced service providers. None of the Company’s employees are currently represented by a union, and the Company believes that it has excellent relations with its employees. 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 other non-core functions.

Business Strategy

Our business strategy is to acquire known, underdeveloped oil and natural gas resources and exploit them through the application of capital, sound engineering and modern technology to increase production, ultimate recoveries, or both. Our principal assets include interests in a CO_2 enhanced oil recovery project in Louisiana’s Delhi field. We are focused on increasing underlying asset values on a per share basis. In doing so, we depend on a conservative capital structure, allowing us to maintain financial control of our assets for the benefit of our shareholders.

Delhi Field - Enhanced Oil Recovery - Onshore Louisiana

Our mineral and working interests in the Delhi Holt-Bryant Unit in the Delhi field ("Unit"), located in Northeast Louisiana, are currently our most significant asset. The Unit is approximately 13,636 acres in size and has had a prolific production history totaling approximately 195 million bbls of oil through primary and limited secondary recovery operations since its discovery in the mid-1940s. Since initial enhanced oil recovery ("EOR") production began in March 2010, the Unit has produced over 11 million bbls of oil. The Unit is currently producing as an EOR project utilizing CO2 flood technology following the sale of a majority of our working interest to a subsidiary of Denbury Resources, Inc., the current operator, in 2006. At the time of our purchase of the field in 2003, the Unit had minimal production.

We own two types of interests in the Unit:

- 7.4% of overriding royalty interests that are in effect for the life of the Unit and mineral royalty interests, free of all operating and capital cost burdens. Effective July 1, 2016, our overriding royalty interest was reduced by 0.2226% to 7.2% as part of the litigation settlement with the operator discussed in Note 3 - Delhi Litigation Settlement; and
- A 23.9% working interest with an associated 19.0% net revenue interest. The working interest reverted to us effective November 1, 2014. Upon occurrence of this contractual payout, we began bearing 23.9% of all operating expenses and capital expenditures and our combined net revenue interests increased to 26.4% through the end of fiscal 2016, and 26.2% thereafter.

Our independent reservoir engineers, DeGolyer & MacNaughton, assigned the following estimated reserves net to our interests at Delhi as of June 30, 2016. Equivalent oil reserves is defined as six MCF of gas and 42 gallons of natural gas liquids to one barrel of oil conversion ratio.

- 10.8 million bbls of proved oil equivalent reserves, with a Standardized Measure of Discounted Future Net Cash Flows ("Standardized Measure") of $78 million, and PV-10* of $101 million
- 4.5 million bbls of probable** oil equivalent reserves
- 2.7 million bbls of possible** oil equivalent reserves

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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. Both the Standardized Measure and PV-10 are based on the average first day of the month net commodity prices received in the twelve months preceding June 30, 2016, which were $40.91 per barrel of oil and $14.38 per barrel of NGL.

** With respect to the above reserve numbers, estimates of Probable and Possible reserves are inherently imprecise. When producing an estimate of the amount of oil and natural gas that is recoverable from a particular reservoir, Probable reserves are those additional reserves that are less certain to be recovered than Proved reserves but which, together with Proved reserves, are as likely as not to be recovered, generally described as having a 50% probability of recovery. Possible reserves are even less certain and generally require only a 10% or greater probability of being recovered. All categories of reserves are continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors. Estimates of Probable and Possible reserves are by their nature much more speculative than estimates of Proved reserves and are subject to greater uncertainties, and accordingly the likelihood of recovering those reserves is subject to substantially greater risk. These three reserve categories and net present worth discounted at 10% relating to each category have not been adjusted to different levels of recovery risk among these categories and are therefore not comparable and are not meaningfully combined.

The operator has planned six primary phases for the installation of the CO_2 flood in the Delhi field. Four of these phases have been completed as of June 30, 2016 and two remain as undeveloped. One of the remaining two phases is reflected as proved undeveloped in our current reserves report and the other was dropped from proved reserves as it was not deemed economic under current year pricing guidelines for SEC purposes.

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 BOPD.

Implementation of Phase II, which was 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. During early calendar 2013, the operator intensified development in the previously redeveloped western side of the field based on production results and new geological mapping that included the results of seismic data acquired over the last few years. Gross field production increased to more than 7,500 BO per day.

In June 2013, following a fluid release event that consisted of the uncontrolled release of CO_2, water, natural gas and a small amount of oil from a previously plugged well in the southwest part of the field, the operator temporarily suspended CO_2 injection in most of the southwestern tip of the field. The operator has fully remediated the affected area, but has isolated that part of the field with a water curtain while continuing production. See discussion below for 2016 developments in this part of the field.

The operator took the position that the remediation costs of the June 2013 fluid release event, which totaled over $130 million on a gross basis, could be charged to our payout account. Accordingly, this action delayed our working interest reversion by more than one year. We disputed the operator's position on the treatment of these costs, filed suit against the operator over this matter and other issues related to the original 2006 agreements and subsequently reached a settlement agreement with the operator as described in Note 3 – Delhi Litigation Settlement.

Subsequent to the June 2013 fluids release, the operator delayed further development of the field and stated its intent not to resume significant capital spending until reversion of our working interest, which became effective on November 1, 2014. In February 2015, subsequent to reversion, we approved an authorization for expenditure ("AFE") for the construction of a natural gas liquids ("NGL") recovery plant in the Delhi Field, which will extract NGL's and methane from the field. We expect that the NGL's will be sold and the recovered methane will be utilized to generate power for the field in order to substantially reduce operating costs, a more cost effective use than selling the methane. In addition to the value of these hydrocarbon products, the increased purity of the CO_2 stream re-injected into the field should result in significant operational benefits to the CO_2 flood. The estimated gross costs of the plant is approximately $103 million; our net share of these capital expenditures is $24.6 million, of which we have already expended approximately $21.5 million. The plant is expected to be operational by November 2016.

During the fall of 2014, post-reversion, the operator initiated work on the Phase V expansion of the CO_2 flood in the undeveloped eastern part of the field. This project is sometimes referred to as Test Site 5. These operations were suspended later that fall when the operator made significant cuts in its capital budget as a result of declining oil prices. While we believe the Phase V expansion is economic at current commodity prices, resumption of this work is likely to be electively delayed due to prevailing oil prices and the partners' allocation of capital for such projects. Since we believe that the NGL plant and further expansion of the CO_2 flood have favorable economics, even in this lower price environment, we expect the expansion of the CO_2 flood to resume within the next few years. The economics of expansion will also be improved subsequent to the completion of the NGL recovery plant.

During the second calendar quarter of 2016, we authorized expenditures totaling $2.5 million gross ($0.6 million net to Evolution) for a project to restore production in the southwestern portion of the field. Following the fluid release event in June 2013, CO_2 injections in this area ceased in order to reduce reservoir pressure and protect the incident area. The project includes converting three shut-in wells to water injector wells in order to expand the water curtain barrier to reduce CO_2 migration into this area together with the installation of three electrical submersible pumps ("ESP") in other shut-in wells in order to increase withdrawal rates and help maintain the targeted reservoir pressure. These ESP production wells will create a modified waterflood, which is expected to increase gross oil production by an estimated 250 to 300 BOPD. At June 30, 2016 this project was still in progress.

At June 30, 2016, no proved, probable or possible reserves were attributed to the suspended southwestern tip area of the field, beneath the inhabited Town of Delhi in the northeast and to one of two development sites on the far eastern side of field (Phase VI) due to the current economics of future development plans. In addition, no probable reserves are currently attributed to three smaller reservoirs within the Unit in similar formations with similar production history due to the lower oil price utilized in our reserves calculation. We do not have proved or probable reserves associated with the Mengel Sand, a separate interval within the Unit that is not currently producing, which was received in the litigation settlement in June 2016.

At June 30, 2016, 1.4 million bbls of oil equivalent proved undeveloped reserves, 0.5 million bbls of oil equivalent probable reserves, and 0.2 million bbls of oil equivalent possible reserves were attributed to Phase V of the undeveloped eastern part of the Delhi field. Development of these proved reserves is forecast to begin in fiscal 2018.

Artificial Lift Technology (GARP®)

Our artificial lift technology registered as GARP® (Gas Assisted Rod Pump) was developed internally by our former Senior Vice President of Operations. Its design is intended to increase production and extend the life of horizontal and vertical wells with gas, oil or associated water production with the expectation of recovering additional reserves at an economically attractive cost per BOE. We received a patent on our GARP® technology on August 30, 2011, which provides U.S. patent protection for the technology through early 2028. We have further filed for a continuation in part to our patent for recent improvements in the technology, including a concentric design which allows the technology to work in narrower diameter casing.

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

Subsequent to receiving our patent, we entered into demonstration joint venture projects with two different industry operators during fiscal 2012 to prove commercial application. We further expanded our commercial tests during fiscal 2013 with two additional installations and a third in fiscal 2014. All five of these installations were successful in re-establishing commercial production. During fiscal 2014, we entered into a commercial agreement to install our technology on at least five wells in the Giddings Field. Three installations were completed as of the end of fiscal 2014, two of which were successful. During fiscal 2015, we completed installation of our artificial lift technology in two additional non-operated wells under this contract. In addition, we restored production in one of our operated wells that had been temporarily abandoned and shut-in since March 2014. The results from these projects were mixed, with many of the wells successfully establishing or restoring commercial rates of production. However, with the declining price environment, many of the wells were not economically successful when including the incremental costs of installing the technology.

As a result of the declining commodity price environment and reduced capital spending by the industry, the timing for commercial success of this technology was slower than previously anticipated. Based on a strategic review of our GARP® artificial lift technology operations, we completed the separation and transfer of these operations to a new entity controlled by the inventor of the technology and certain former employees of the Company, effective December 31, 2015. We invested $108,750 in common and preferred stock and retained a minority interest in the new entity, together with a 5% royalty on all future gross revenues derived from the technology. We have the option to convert our preferred stock investment into a larger, non-controlling equity stake in the new entity. Consequently, we have retained substantial upside for our shareholders from the potential future success of the technology, while eliminating approximately $1.0 million annually of overhead expense associated with GARP®. We have also retained the right to use the technology in our current wells and any future wells we develop or acquire.

Other Projects

Lopez Field—South Texas

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

Mississippi Lime—Kay County, Oklahoma

In 2012, we acquired a 45% interest in a joint venture with Orion Exploration, a private company based in Tulsa, Oklahoma. The joint venture was operated by Orion and engaged in the horizontal development of the Mississippi Lime reservoir in Kay County, Oklahoma. Our leasehold position, totaling approximately 6,600 acres, was located in the eastern, more oil-prone side of the play. We drilled one gross salt water disposal well and reached total depth on two horizontally drilled wells in the Mississippi Lime formation. While both wells produced at the fluid rates expected, the quantities of oil and gas were far less than expected. We subsequently reworked both wells to test the role of structure in production, and determined that this play is a structural play requiring substantial geophysical and geological work and expertise in order to be successful, as opposed to a resource play in which engineering is the primary requirement. Accordingly, we elected in fiscal 2013 to reduce our joint venture interest in undeveloped leases to 33.9%, resulting in a $1.2 million reduction in both our net property and accounts payable. In October 2014, we closed on the sale of all of our leasehold interests, wells and associated assets in the Mississippi Lime reservoir to the operator.

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 working interest production in-kind, we are currently selling our under the Delhi operator's agreement with Plains Marketing LP for the delivery and pricing of our oil there. The oil from Delhi is currently transported from the field by pipeline, which results in better net pricing than the alternative of transportation by truck. Delhi crude oil production sells at Louisiana Light Sweet ("LLS") pricing which generally trades at a premium to West Texas Intermediate ("WTI") crude oil pricing. This positive LLS Gulf Coast price differential over WTI Cushing was approximately $2.19 per barrel during our fiscal year ended June 30, 2016, based on first of the month prices. The differential has narrowed from past years, but we expect that a positive LLS price differential will continue, at least in the near future.

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

Customer	Year Ended June 30, 2016	2015	2014
Plains Marketing L.P. (includes Delhi production)	99 %	99 %	96 %
Enterprise Crude Oil LLC	— %	— %	2 %
Flint Hills	— %	— %	1 %
ETC Texas Pipeline, LTD.	— %	— %	1 %
All others	1 %	1 %	— %
Total	100%	100%	100%

The loss of our purchaser at the Delhi field or disruption to pipeline transportation from the field could adversely affect our net realized pricing and potentially our near-term production levels. The loss of any of our other purchasers would not be expected to have a material adverse effect on our operations.

Market Conditions

Marketing of crude oil, natural gas, and natural gas liquids and the prices we receive are 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 30 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. Most recently, the price of oil per barrel has dropped dramatically, particularly in the fourth quarter 2014 and continuing into 2016, by more than half since its high in June 2014. 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.

Also over the past 30 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 and non-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, 1155 Dairy Ashford Road, Suite 425, Houston, Texas 77079, 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

Our business involves a high degree of risk. If any of the following risks, or any risk described elsewhere in this Annual Report on Form 10-K, actually occurs, our business, financial condition or results of operations could suffer. The risks described below are not the only ones facing us. Additional risks not presently known to us or which we currently consider immaterial also may adversely affect us.

Risks related to the oil and gas industry and our Company

A substantial or extended decline in oil prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The price we receive for our oil significantly influences our revenue, profitability, access to capital and future rate of growth. Oil is a commodity and its price is subject to wide fluctuations in response to relatively minor changes in supply and demand. For example, average daily prices for WTI crude oil ranged from a high of $111 per barrel to a low of $27 per barrel over the past three fiscal years ending June 30, 2016. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic conditions impacting the global supply and demand for oil and gas;
- actions of OPEC;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions in or affecting other oil-producing and natural gas-producing countries;
- the level of global oil and natural gas exploration and production;
- the level of global oil and natural gas inventories;
- localized supply and demand fundamentals of regional, domestic and international transportation availability;
- weather conditions and natural disasters;
- domestic and foreign governmental regulations;
- speculation as to the future price of oil and the speculative trading of oil and natural gas futures contracts;
- price and availability of competitors' supplies of oil and natural gas;
- technological advances effecting energy consumption; and
- the price and availability of alternative fuels.

Substantially all of our production is sold to purchasers under short-term (less than twelve-month) contracts at market-based prices. Low oil and natural gas prices will reduce our cash flows, borrowing ability, the present value of our reserves and our ability to develop future reserves. We may be unable to obtain needed capital or financing on satisfactory terms. Low oil and natural gas prices may also reduce the amount of oil and natural gas that we can produce economically, which could lead to a decline in our oil and natural gas reserves. Because approximately 79% of our proved reserves at June 30, 2016 are crude oil reserves and 21% are natural gas liquids reserves, and almost 100% of our current production is crude oil, we are heavily impacted by movements in crude oil prices, which also influence natural gas liquids prices. To the extent that we have not hedged our production with derivative contracts or fixed-price contracts, any significant and extended decline in oil and natural gas prices may adversely affect our financial position.

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 and financial results.

Over 99% of our revenues come from our royalty, mineral and working interests in the Delhi field in Louisiana and thus our current revenues are highly concentrated in this field. 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 and financial results. We are not the operator of the Delhi field, and our revenues and future growth are heavily dependent on the success of operations, which we do not control.

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

In general, the volumes of production from crude oil and natural gas properties decline as reserves are depleted, with the rate of decline depending on reservoir characteristics. Except to the extent we acquire additional properties containing proved reserves or conduct successful development activities, or both, our proved reserves will decline. Our production is heavily dependent on our interests in EOR production that began during March 2010 in the Delhi field. Although EOR production from proved reserves at Delhi has and is expected to grow over time, environmental or operating problems or lack of future investment at Delhi could cause our net production of oil and natural gas to decline significantly over time, which could have a material adverse effect on our financial condition.

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

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

We are materially dependent upon our operator with respect to the successful operation of our principal asset, which consists of our interests the Delhi field. A materially negative change in our operator’s financial condition could negatively affect operations in the Delhi field, and consequently our income from the field as well as the value of our interests in the Delhi field.

Our royalty, mineral and working interests in the Delhi field, located in Northeast Louisiana, are currently our most significant asset. Over 99% of our revenues come from these interests and thus our current revenues are highly concentrated in this field. Any significant downturn in production or other events beyond our control which impact the Delhi field could have a material adverse effect on our results of operations and financial results. We are not the operator of the Delhi field. It is operated by a subsidiary of Denbury Resources Inc. (“DNR”). Our revenues and future growth are thus heavily dependent on the success of operations which we do not control.

Further, our CO_2- Enhanced Oil Recovery (“CO_2-EOR”) project in the Delhi field requires significant amounts of CO_2 reserves and technical expertise, the sources of which have been committed by the operator. Additional capital remains to be invested to fully develop this project, further increase production and maximize the value of this asset. The operator's failure to manage these and other technical, environmental, operating, strategic, financial and logistical matters could cause ultimate enhanced recoveries from the planned CO_2- EOR project to fall short of our expectations in volume and/or timing. Such occurrences could have a material adverse effect on us, and our results of operations and financial condition.

Our economic success is thus materially dependent upon the Delhi field operator's ability to: (i) deliver sufficient quantities of CO_2 from its reserves in the Jackson Dome source, (ii) secure its share of capital necessary to fund development and operating commitments with respect to the field and (iii) successfully manage related technical, operating, environmental, strategic and logistical risks, among other things.

During the fall of 2014, the operator initiated work on expansion of the CO_2 flood in the undeveloped eastern part of the field. These operations were suspended by the end of 2014 when the operator made significant cuts in its capital budget as a result of declining oil prices. While we believe that expansion remains economic at current commodity prices, resumption of this work could be electively delayed due to prevailing oil prices and the operator's allocation of capital for such projects, thereby negatively impacting us.

We are aware that DNR, which is publicly traded, has disclosed in its public SEC filings certain risks related to its current level of indebtedness and the related financial covenants. They have stated, for example, that their level of indebtedness could have important consequences, including, among others, requiring dedication of a substantial portion of DNR's cash flow from operations to servicing their indebtedness. They noted that their ability to meet their obligations under their debt instruments will depend in part upon prevailing economic conditions and commodity prices. DNR also noted that it had deferred development spending for certain projects.

Given the current stress in the global commodity markets and oil and gas in particular, our operator could be materially negatively impacted, which could in turn negatively affect the operator's ability to operate the Delhi field as well as its financial commitment to the CO_2-EOR project in the field, and thus our interests in the Delhi field could be materially negatively impacted.

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

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

Our 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, additional capital remains to be invested to fully develop the EOR project, further increase production and maximize the value of the asset. 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, its results of operations and financial condition.

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

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

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

Drilling or re-working is a highly speculative activity. Even when fully and correctly utilized, modern well completion techniques such as 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 also identify and develop prospects through a number of methods, some of which do not include horizontal drilling or tertiary injectants, and some of which may be unproven. The drilling and results for these prospects may be particularly uncertain. We cannot assure you that these projects can be successfully developed or that the wells discussed will, if drilled, encounter reservoirs of commercially productive crude oil or natural gas.

The loss of a large single purchaser of our oil and natural gas could reduce the competition of our production.
For the year ended June 30, 2016, one purchaser accounted for 99% of our oil and natural gas revenues. We do not currently market our share of crude oil production from the Delhi field. Although we have the right to take our working interest production in-kind, we are currently accepting terms under the Delhi operator's agreement with Plains Marketing L.P. for the delivery and pricing of our oil there. The loss of such large single purchaser for our oil and natural gas production could negatively impact the revenue we receive. We cannot assure you we could readily find other purchasers for our oil and natural gas production. In addition, the crude oil production from the Delhi field is transported by pipeline and if this pipeline transportation were disrupted and we were forced to use alternative transportation methods, our net realized pricing and potentially our near-term production levels could be adversely affected.
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 therefrom 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. The Standardized Measure and PV-10 do not necessarily correspond to market value.
Regulatory and accounting requirements may require substantial reductions in reporting proven reserves.
We review on a periodic basis the carrying value of our crude oil and natural gas properties under the applicable rules of the various regulatory agencies, including the SEC. Under the full cost method of accounting that we use, the after-tax carrying value of our oil and natural gas properties may not exceed the present value of estimated future net after-tax cash flows from proved reserves, discounted at 10%. Application of this "ceiling" test requires pricing future revenues at the previous 12-month average beginning-of-month price and requires a write down of the carrying value for accounting purposes if the ceiling is exceeded. We may in the future be required to write down the carrying value of our crude oil and natural gas properties when crude oil and natural gas prices are depressed or unusually volatile. Whether we will be required to take such a charge will depend in part on the prices for crude oil and natural gas during the previous period and the effect of reserve additions or revisions and capital expenditures during such period. If a write down is required, it would result in a current charge to our earnings but would not impact our current cash flow from operating activities.

Our derivative activities could result in financial losses or could reduce our income.

To achieve more predictable cash flows and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we currently, and may in the future, enter into derivative arrangements for a portion of our oil and natural gas production, including costless collars and fixed-price swaps. We have not designated any of our derivative instruments as hedges for accounting purposes and record all derivative instruments on our balance sheet at fair value. Changes in the fair value of our derivative instruments are recognized in earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments. Derivative arrangements also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counterparty to the derivative instrument defaults on its contract obligations; or
- there is an increase in the differential between the underlying price in the derivative instrument and actual price received.

In addition, some of these types of derivative arrangements limit the benefit we would receive from increases in the prices for oil and natural gas and may expose us to cash margin requirements.

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

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

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

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

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

Our cash flow from our reserves may not be sufficient to fund our ongoing activities at all times. From time to time, we may require additional financing in order to carry out our oil and gas acquisitions, exploitation and development activities. Certain of our undeveloped leasehold acreage may be 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 may be subject to risks in connection with acquisitions because of uncertainties in evaluating recoverable reserves, well performance and potential liabilities, as well as uncertainties in forecasting oil and gas prices and future development, production and marketing costs, and the integration of significant acquisitions may be difficult.

We periodically evaluate acquisitions of reserves, properties, prospects and leaseholds and other strategic transactions that appear to fit within our overall business strategy. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves
- future oil and natural gas prices and their appropriate differentials;
- development and operating costs
- potential for future drilling and production;

- validity of the seller's title to properties, which may be less than expected at closing; and
- potential environmental issues, litigation and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing

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or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and potential recoverable reserves. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities or title defects in excess of the amounts claimed by us before closing and acquire properties on an “as is” basis. Indemnification from the sellers will generally be effective only during the twelve-month period after the closing and subject to certain dollar limitations and minimums. We may not be able to collect on such indemnification because of disputes with the sellers or their inability to pay. Moreover, there is a risk that we could ultimately be liable for unknown obligations related to acquisitions, which could materially adversely affect our financial condition, results of operations or cash flows.
Significant acquisitions and other strategic transactions may involve other risks, including:

- our lean management team's capacity could be challenged by the demands of evaluating, negotiating and integrating significant acquisitions and strategic transactions in concert with the Company's on going business demands.
- the challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with those of our operations while carrying on our ongoing business;
- difficulty associated with coordinating geographically separate organizations;
- an inability to secure, on acceptable terms, sufficient financing that my be required in connection with expanded operations and unknown liabilities; and
- the challenge of attracting and retaining personnel associated with acquired operations.

The process of integrating assets could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer. In addition, even if we successfully integrate the assets acquired in an acquisition, it may not be possible to realize the full benefits we may expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition or realize these benefits within the expected time frame.
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.
Our insurance may not protect us against all of the operating risks to which our business is exposed.

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

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 Executive Chairman, Randall D. Keys, our President and Chief Executive Officer, and David Joe, Senior Vice President, Chief Financial Officer and Treasurer, for sourcing, evaluating and closing deals, capital raising, and oversight of development and operations. Presently, the Company is not a beneficiary of any key man insurance.

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

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

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

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

We face strong competition from larger oil and gas companies.

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

We have been, 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.

From time to time we may be a defendant or plaintiff in various lawsuits. The nature of our operations exposes us to further possible litigation claims in the future. There is risk that any matter in litigation could be decided unfavorably against us regardless of our belief, opinion, and position, which could have a material adverse effect on our financial condition, results of operations, and cash flow. Litigation can be very costly, and the costs associated with defending litigation could also have a material adverse effect on our financial condition. Adverse litigation decisions or rulings may damage our business reputation.

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

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

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

During the last few years, concerns over inflation, energy costs, declining oil and gas prices, geopolitical issues, the availability and cost of credit, the U.S. mortgage market, uncertainties with regard to European sovereign debt, the slowdown in economic growth in large emerging and developing markets, such as China, and other issues 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 domestic and international financial markets and commodity prices. If uncertain or poor economic, business or industry conditions in the United States or abroad remain prolonged, demand for petroleum products could diminish or stagnate, which could impact the price at which we can sell our oil, natural gas, and NGLs, affect our vendors', suppliers' and customers' ability to continue operations, and ultimately adversely impact our results of operations, liquidity, and financial condition.

Risks Associated with Our Stock

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

Our common stock has relatively low trading volume and the market price has been, and is likely to continue to be, volatile. For example, during the fiscal year ending June 30, 2016, our stock price as traded on the NYSE MKT ranged from $3.60 to $7.54. The variance in our stock price makes it difficult to forecast with any certainty the stock price at which an investor may be able to buy or sell shares of our common stock. The market price for our common stock could be subject to fluctuations as a result of factors that are out of our control, such as:

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

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

Our executive officers and directors, in the aggregate, beneficially own approximately 2.8 million shares, or approximately 8.5% of our beneficial common stock base. JVL Advisors LLC controls approximately 4.9 million shares or approximately 14.8% of our outstanding common stock, and Advisory Research controls approximately $3.5 million shares or 10.6% of our outstanding common stock. As a result, these holders could exercise significant influence over matters submitted to our stockholders for approval (including the election and removal of directors and any merger, consolidation or sale of all or substantially all of our assets). This concentration of ownership may have the effect of delaying, deferring or preventing a change in control of our company, impede a merger, consolidation, takeover or other business combination involving our company or discourage a potential acquirer from making a tender offer or otherwise attempting to obtain control of our company, which in turn could have an adverse effect on the market price of our common stock.

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

Our common stock is relatively thinly traded on the NYSE MKT. During the fiscal year ending June 30, 2016, the daily trading volume in our common stock ranged from a low of 14,600 shares to a high of 292,100 shares traded, with average daily trading volume of 69,732 shares. On most days, this trading volume means that there is relatively 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 three 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 1, 2016. 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.

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

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

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

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

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

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

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

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

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

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

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

Series A Preferred Stock. Upon our liquidation, our obligations to our creditors would rank senior to our Series A Preferred Stock and would be required to be paid before any payments could be made to holders of our Series A Preferred Stock.

Continued payment of dividends on our Common Stock could be impacted.

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

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

The information required by Item 2. is contained in Item 1. Business

Oil & Gas Properties

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

Estimated Oil and Natural Gas Reserves and Estimated Future Net Revenues

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

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

Estimates of Probable and Possible reserves are inherently imprecise. When producing an estimate of the amount of oil and natural gas that is recoverable from a particular reservoir, Probable reserves are those additional reserves that are less certain to be recovered than Proved reserves but which, together with Proved reserves, are as likely as not to be recovered, generally described as having a 50% probability of recovery. Possible reserves are even less certain and generally require only a 10% or greater probability of being recovered. All categories of reserves are continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors. Estimates of Probable and Possible reserves are by their nature much more speculative than estimates of Proved reserves and are subject to greater uncertainties, and accordingly the likelihood of recovering those reserves is subject to substantially greater risk. These three reserve categories and net present worth discounted at 10% relating to each category have not been adjusted to different levels of recovery risk among these categories and are therefore not comparable and are not meaningfully combined.

Estimated pre-tax 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 2016

Our proved, probable and possible reserves at June 30, 2016, denominated in equivalent barrels using six MCF of gas and 42 gallons of natural gas liquids to one barrel of oil conversion ratio, were estimated by our independent petroleum engineer, DeGolyer and MacNaughton ("D&M"). D&M was selected for our interests in the Delhi field due to their expertise in CO2-EOR projects and to ensure consistency with the operator who also uses D&M for their reserves estimates in the Delhi field. We also chose to have D&M estimate our Giddings properties beginning in 2015 in order to simplify and consolidate our reserve reporting. D&M has significant expertise in this region as well. The scope and results of their procedures are summarized in a letter from the firm, which is included as exhibit 99.4 to this Annual Report on Form 10-K.

The following table sets forth our estimated proved and probable reserves as of June 30, 2016. See Note 23 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 $42.91 per barrel of crude oil and $14.38 per barrel of natural gas liquids. The price of natural gas liquids was based on the historical price received, if no historical received price is available, historical pricing in the area. Pricing differentials were applied to all properties, on an individual property basis. Quality adjustments have been applied based on actual BTU factors for each well and a shrinkage factor has been applied based on production volumes versus actual sales volumes.

Reserves as of June 30, 2016

Reserve Category	Oil (MBbls)	NGLs (MBbls)	Total Reserves (MBOE)*
PROVED			
Developed (66% of Proved)	7,168	—	7,168
Undeveloped (34% of Proved)	1,420	2,235	3,655
TOTAL PROVED	8,588	2,235	10,823
Product Mix	79 %	21 %	100 %
PROBABLE			
Developed (69% of Probable)	3,092	—	3,092
Undeveloped (31% of Probable)	471	934	1,405
TOTAL PROBABLE	3,563	934	4,497
Product Mix	79 %	21 %	100 %
POSSIBLE			
Developed (72% of Possible)	1,964	—	1,964
Undeveloped (28% of Possible)	187	563	750
TOTAL POSSIBLE	2,151	563	2,714
Product Mix	79 %	21 %	100 %

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

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

Reconciliation of Changes in Proved Reserves by Major Property

Proved reserves, MBOE	Delhi Field MBOE	Giddings Field MBOE	Proved Total MBOE
June 30, 2015	12,413.8	32.6	12,446.4
Production	(655.9)	(2.9)	(658.8)
Revisions	(934.5)	(29.7)	(964.2)
Sales of minerals in place	—	—	—
Improved recovery, extensions and discoveries	—	—	—
June 30, 2016	10,823.4	—	10,823.4

Reconciliation of Changes in Probable Reserves by Major Property

Probable reserves, MBOE	Delhi Field MBOE	Giddings Field MBOE	Probable Total MBOE
June 30, 2015	9,339.4	—	9,339.4
Revisions	(4,842.1)	—	(4,842.1)
Sales of minerals in place	—	—	—
Improved recovery, extensions and discoveries	—	—	—
June 30, 2016	4,497.3	—	4,497.3

Reconciliation of Changes in Possible Reserves by Major Property

Possible reserves, MBOE	Delhi Field MBOE	Giddings Field MBOE	Possible Total MBOE
June 30, 2015	2,954.4	—	2,954.4
Revisions	(240.4)	—	(240.4)
Sales of minerals in place	—	—	—
Improved recovery, extensions, and discoveries	—	—	—
June 30, 2016	2,714.0	—	2,714.0

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

The following table provides a reconciliation of PV-10 of our proved properties to the Standardized Measure as shown in Note 23 of the consolidated financial statements.

	For the Years Ended June 30, 2016	2015
Estimated future net revenues	$187,713,581	$448,113,943
10% annual discount for estimated timing of future cash flows	86,844,543	229,407,446
Estimated future net revenues discounted at 10% (PV-10)	100,869,038	218,706,497
Estimated future income tax expenses discounted at 10%	(22,911,719)	(59,509,958)
Standardized Measure	$77,957,319	$159,196,539

The following table provides a reconciliation of PV-10 of each of our proved properties to the Standardized Measure as shown in Note 23 of the consolidated financial statements.

	For the Years Ended June 30, 2016	2015
Delhi Field	$100,869,038	$218,320,579
Giddings Field	—	385,918
Estimated future net revenues discounted at 10% (PV-10)	$100,869,038	$218,706,497
Estimated future income tax expenses discounted at 10%	(22,911,719)	(59,509,958)
Standardized Measure	$77,957,319	$159,196,539

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

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

Our policies regarding internal controls over reserve estimates require reserves to be prepared by an independent engineering firm under the supervision of our Executive Chairman, our Chief Executive Officer and our former Senior Vice President of Operations, acting as a consultant to the Company, and to be in compliance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC. Our Executive Chairman holds B.S. and M.E. degrees from Rice University in chemical engineering and earned an M.B.A. from Harvard University. He has over 30 years of experience in engineering, energy transactions, operations and finance with small independents, larger independents and major integrated oil companies. Our Chief Executive Officer holds a Bachelor of Business Administration degree from the University of Texas at Austin. He has over 30 years of experience in the energy industry, encompassing both upstream oil and gas companies and the oilfield service industry. Our Consultant has over 30 years of experience in oil and gas operations and holds a Bachelor of Science in Petroleum Engineering degree from the University of Oklahoma at Norman. The reserve information in this filing is based on estimates prepared by DeGoyler and MacNaughton, our independent engineering firm. The person responsible for preparing the reserve report is a Registered Professional Engineer in the State of Texas and a Senior Vice President of the firm. He holds a Bachelor of Science degree in Geology in 1973 from Eastern New Mexico University and earned a Master of Science degree in Petroleum Engineering from the University of Texas at Austin in 1975.

He has over 36 years of oil and gas reservoir experience. We provide our engineering firm with property interests, production, current operating costs, current production prices and other information. This information is reviewed by our Senior Management and outside consultant to ensure accuracy and completeness of the data prior to submission to our independent engineering firm. The scope and results of our independent engineering firm's procedures, as well as their professional qualifications, are summarized in the letter included as exhibit 99.4 to this Annual Report on Form 10-K.

Proved Undeveloped Reserves

Our proved undeveloped reserves were 3,655 MBOE at June 30, 2016 with associated future development costs of approximately $14.9 million. During the year ended June 30, 2016, we incurred $16.5 million of capital spending toward proved undeveloped reserves, primarily related to the NGL plant, but the plant was not complete at the end of the year, so those reserves are still reflected as proved undeveloped. The 1,442 MBOE decrease from 5,097 MBOE at June 30, 2015 is due to a 1,091 MBOE decrease for Phase VI, a portion of the remaining undeveloped eastern area of the Delhi field that presently is uneconomic due to a lower oil price, a 154 MBOE decline in our remaining eastern area reserves and a 197 MBOE decrease in NGL plant reserves. The Phase VI eastern patterns no longer in our proved undeveloped reserves had significantly less recoverable reserves and higher future development costs than the Phase V project we continue to carry as proved undeveloped. There were no reclassifications of proved undeveloped reserves to probable or possible reserves.

The initial assignment of proved undeveloped reserves in the Delhi field was made on June 30, 2010, which involved a large scale CO_2 enhanced oil recovery project. The operator’s development plans for the field have remained essentially unchanged and were originally scheduled to be completed by June 30, 2015, within five years from the initial recording of such proved reserves. The field is approximately 66% developed as of June 30, 2016. However, as a result of the adverse fluid release event in the field in June 2013 and the resulting delay in reversion of our working interest, development of the field was not completed as scheduled. Although no unproved reserves were converted to proved reserves during fiscal 2015 and 2016, development expenditures were ongoing. Expansion of the CO_2 flood to the remaining undeveloped eastern portion of the field commenced subsequent to reversion of our working interest in late calendar 2014. The Company incurred $3.8 million of capital expenditures until the operator suspended this project as a result of a significant reduction in its capital spending. During the year ended June 30, 2015 the NGL plant project and began and the Company incurred $5.0 million of related capital expenditures. In the year ended June 30, 2016, the Company incurred an additional $16.5 million of plant capital expenditures with $3.1 million budgeted for its completion expected in the fourth calendar quarter of 2016. At June 30, 2016, $11.6 million of net future capital expenditures also remained for development of the eastern part of the field that was suspended in late 2014 and is now planned to continue over the next two fiscal years and is expected to be completed by December 31, 2018, approximately seven and one half years after the initial recording of proved reserves. The 2013 addition of the NGL plant project to recover natural gas liquids and methane required additional planning and has resulted in a prudent delay in the full development of the field's proved reserves. Given the nature of CO_2 EOR projects, we believe that the undeveloped reserves in the Delhi field satisfy the conditions to continue to be included as proved undeveloped reserves because (1) we established and continue to follow the previously adopted development plan for this project as adjusted to incorporate the completion of the NGL plant in 2016 and delays relating to the 2013 fluid release event; (2) we have significant ongoing development activities at this project that, as budgeted and currently being expended, reflect a significant and sufficient portion of remaining capital expenditures to convert proved undeveloped reserves to proved developed reserves; and (3) the operator has a historical record of completing the development of comparable long-term projects.

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, 2016		Year Ended June 30, 2015		Year Ended June 30, 2014	
Product	Volume	Price	Volume	Price	Volume	Price
Crude oil (Bbls)	658,041	$39.71	450,713	$61.59	169,783	$102.84
Natural gas liquids (Bbls)	491	$16.06	1,358	$27.41	3,516	$33.32
Natural gas (Mcf)	1,620	$1.79	7,981	$3.33	26,655	$3.60
Average price per BOE*	658,802	$39.68	453,401	$61.37	177,742	$99.43
Production costs	Amount	per BOE	Amount	per BOE	Amount	per BOE
Production costs, excluding ad valorem and production taxes	$8,767,490	$13.31	$9,285,396	$20.48	$1,148,974	$6.46
Total production costs, including ad valorem and production taxes	$9,062,179	$13.76	$9,335,244	$20.59	$1,193,573	$6.72

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

Drilling Activity

Our productive drilling activity during the past three fiscal years ended June 30, 2016, was limited to one fiscal 2015 gross (.239 net) development well drilled in the Delhi field. No dry wells were drilled in the past three fiscal years.

Present Activities

During fiscal year 2015, construction of a natural gas liquids ("NGL") recovery plant commenced in the Delhi field, which will extract and sell NGL's from the field. In addition to the value of these hydrocarbon products, the increased purity of the CO_2 stream re-injected into the field should result in significant operational benefits to the CO_2 flood. Project construction continued during fiscal year 2016, with completion expected late in calendar 2016.

During the fourth fiscal quarter of fiscal 2016, the operator of the Delhi field commenced a project to restore production in the southwestern portion of the field. Following the fluid release event in June 2013, CO_2 injections in this area ceased in order to reduce reservoir pressure and protect the incident area. The project includes converting three shut-in wells to water injector wells in order to expand the water curtain barrier to reduce CO_2 migration into this area together with the installation of three electrical submersible pumps ("ESP") in other shut-in wells in order to increase withdrawal rates and help maintain the targeted reservoir pressure. These ESP production wells will create a modified waterflood, which is expected to increase gross oil production by an estimated 250 to 300 BOPD.

For further discussion, see "Highlights for our fiscal year 2016" and "Capital Budget" under Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations of this Form 10-K.

Delivery Commitments

As of June 30, 2016, we were not committed to provide a fixed and determinable quantity of oil, NGLs or gas under existing agreements, nor do we currently intend to enter into any such agreements.

Productive Wells

The following table sets forth the number of productive oil and gas wells in which we owned a working interest as of June 30, 2016. See discussion below related to the expected disposition of our three company operated wells.

	Company Operated		Non-Operated		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude oil	3	2.9	89	21.3	92	24.2
Natural gas	—	—	—	—	—	—
Total	3	2.9	89	21.3	92	24.2

Acreage Data

The following table sets forth certain information regarding our developed and undeveloped lease acreage as of June 30, 2016. Developed acreage refers to acreage on which wells have been drilled or completed to a point that would permit production of oil and gas in commercial quantities. Undeveloped acreage refers to acreage on which wells have not been drilled or completed to a point that would permit production of oil and gas in commercial quantities whether or not the acreage contains proved reserves.

Field	Developed Acreage		Undeveloped Acreage		Total	
	Gross	Net	Gross	Net	Gross	Net
Delhi Field, Louisiana*	9,126	2,180	4,510	1,077	13,636	3,257
Giddings Field, Texas**	2,168	2,134	—	—	2,168	2,134
Total	11,294	4,314	4,510	1,077	15,804	5,391

When the Company acquired the Delhi field in 2003, the field had been fully developed through primary and secondary recovery and all of such acreage was reflected as developed acreage. With the addition of a CO_2-EOR project in the field, certain acreage is now reflected as undeveloped using tertiary recovery operations. We estimate that our developed acreage currently includes 9,126 gross (2,180 net) acres in the Delhi field, with approximately 4,510 gross (1,077 net) acres attributable to the remaining undeveloped areas in the eastern part of the field. We own a 23.9% working interest in the field. We are not the operator of the EOR project.

In addition, our developed acreage includes 2,168 gross (2,134 net) in the Giddings Field comprising of a 100% working interest in two producing wells and a 99% working interest in one well subject to a back-in reversion of 22.5%. None of these wells are currently producing at economic rates in the current price environment. Subsequent to year end, we transferred one well back to the previous operator under our contractual agreement. At this time, we expect to plug and abandon the other two wells.

*Includes from the surface of the earth to the top of the Massive Anhydride, less and except the Delhi Holt Bryant CO2 and Mengel Units. As the Delhi field is a unitized field, undrilled acreage is held by production as long as production is maintained in the unit.

**Excludes acreage for small overriding royalty interests retained in various formations in the Giddings Field area.

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 18 – Commitments and Contingencies under Item 8. Financial Statements for a description of legal proceedings, which is incorporated herein by reference.

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". The following table shows, for each quarter of the fiscal years ended June 30, 2016 and 2015, the high and low sales prices for EPM as reported by the NYSE MKT.

NYSE MKT: EPM

2016:	High	Low
Fourth quarter ended June 30, 2016	$5.97	$4.45
Third quarter ended March 31, 2016	$5.12	$3.60
Second quarter ended December 31, 2015	$7.54	$4.70
First quarter ended September 30, 2015	$6.70	$4.02

2015:	High	Low
Fourth quarter ended June 30, 2015	$7.97	$5.77
Third quarter ended March 31, 2015	$8.10	$5.68
Second quarter ended December 31, 2014	$10.25	$6.50
First quarter ended September 30, 2014	$11.19	$8.95

Shares Outstanding and Holders

As of June 30, 2016, there were 32,907,863 shares of common stock issued and outstanding, held by approximately 218 holders of record.

Dividends

We began paying cash quarterly dividends on our common stock in December 2013, at a rate of $0.10 per share and adjusted the rate to $0.05 per share in March 2015. As of June 30, 2016, we had paid eleven consecutive quarterly dividends on our common stock. All dividends on our Series "A" Perpetual Preferred stock have been timely declared and paid monthly. Any future determination with regard to the payment of dividends will be at the discretion of the Board of Directors and will be dependent upon our future earnings, financial condition, applicable dividend restrictions and capital requirements and other factors deemed relevant by the Board of Directors. Under our current revolving credit facility, exceeding the ratio of trailing twelve month's EBITDA minus trailing twelve month's dividends paid to debt service, as defined, would restrict our ability to pay common stock dividends.

Performance Graph

The following graph presents a comparison of the yearly percentage change in the cumulative total return on our Common Stock over the period from June 30, 2011 to June 30, 2016 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, 2011 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:				
Outstanding options	35,231	(1)	$ 2.19	
Outstanding contingent rights to shares	91,172	(1)	—	
Total	126,403		$ 0.61	282,133
Equity compensation plans not approved by security holders	—		—	—
Total	126,403		$ 0.61	282,133

(1) As of June 30, 2016, there were 35,231 shares of common stock issuable upon exercise of outstanding stock options. The Amended and Restated 2004 Stock Plan (the "Plan") provides for the issuance of a total of 6,500,000 common shares. Under the Plan as of June 30, 2016, 3,904,134 common shares had been issued upon the exercise of stock options, 2,187,330 shares of restricted common stock had been issued (of which 406,848 were unvested as of June 30, 2016), contingent restricted stock grants of 91,172 shares had been reserved but not issued (all of which are unvested) and 282,133 shares of common stock remain available for future grants.

Issuer Purchases of Equity Securities

Period	(a) Total Number of Shares (or Units) Purchased (1) (2)	(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, 2016 to April 30, 2016	none	—	—	—
May 1, 2016 to May 31, 2016	none	—	—	—
June 1, 2016 to June 30, 2016	229 shares of Common Stock	$5.70	265,762	Approximately $3.4 million

(1) During the fourth fiscal quarter ended June 30, 2016, the Company received 229 shares of common stock from certain of its employees which were surrendered in exchange for their payroll tax liabilities arising from vestings of restricted stock. The acquisition cost per share reflected the weighted-average market price of the Company's shares at the dates vested.

(2) During fiscal 2016, the Company repurchased 202,390 shares for a total cost of $1.17 million, including commissions. Under the program's terms, shares may be repurchased only on the open market and in accordance with the requirements of the Securities and Exchange Commission. The timing and amount of repurchases will depend upon several factors, including financial resources and market and business conditions. There is no fixed termination date for this repurchase program, and the repurchase program may be suspended or discontinued at any time. Such shares were initially recorded as treasury stock, then subsequently canceled.

Item 6. Selected Financial Data

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

	June 30, 2016	2015	2014	2013	2012
Income Statement Data					
Revenues	$26,349,502	$27,841,265	$17,673,508	$21,349,920	$17,962,038
Cost of revenues	9,133,111	9,355,613	1,193,573	1,780,738	1,774,999
Depreciation, depletion, and amortization	5,165,120	3,615,737	1,228,685	1,300,207	1,136,974
Accretion expense	49,054	34,866	41,626	72,312	77,505
General and administrative expense	9,079,597	6,256,783	8,388,291	7,495,309	6,143,286
Restructuring charges	1,257,433	(5,431)	1,293,186	—	—
Income from operations	1,665,187	8,583,697	5,528,147	10,701,354	8,829,274
Other income (expense)	32,565,954	(147,619)	(38,836)	(43,165)	3,778
Income tax provision	9,570,779	3,444,221	1,891,998	4,029,761	3,700,922
Net income attributable to the Company	$24,660,362	$4,991,857	$3,597,313	$6,628,428	$5,132,130
Dividends on Series A Preferred Stock	674,302	674,302	674,302	674,302	630,391
Net income attributable to common shareholders	$23,986,060	$4,317,555	$2,923,011	$5,954,126	$4,501,739
Earnings per common share:					
Basic	$0.73	$0.13	$0.09	$0.21	$0.16

Diluted	$0.73	$0.13	$0.09	$0.19	$0.14

	June 30, 2016	June 30, 2015	June 30, 2014	June 30, 2013	June 30, 2012
Balance Sheet Data					
Total current assets	$37,086,450	$23,693,048	$26,304,803	$27,436,076	$16,769,789
Total assets	97,451,051	69,882,727	65,015,752	66,556,296	58,955,486
Total current liabilities	8,528,908	9,329,257	2,999,726	2,632,750	5,088,917
Total liabilities	21,129,901	21,306,150	13,138,230	11,720,135	12,332,698
Stockholders' equity	76,321,150	48,576,577	51,877,522	54,836,161	46,622,788
Number of common shares outstanding	32,907,863	32,845,205	32,615,646	28,608,969	27,882,224

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

The following discussion and analysis should be read in conjunction with our Consolidated Financial Statements and Notes thereto included in Item 8, Financial Statements and Supplementary Data. Our discussion and analysis includes forward-looking information that involves risks and uncertainties and should be read in conjunction with Risk Factors under Item 1A of this Form 10-K, along with Forward-Looking Information at the beginning of this report for information on the risks and uncertainties that could cause our actual results to be materially different from our forward-looking statements.

Executive Overview

General

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

Our strategy is to grow the value of our Delhi assets to maximize the value realized by our shareholders. In addition, we plan to return cash to the shareholders in the form of quarterly cash dividends and potential stock buybacks under our previously announced share repurchase program.

We expect to fund our fiscal 2017 capital program from working capital and net cash flows from our properties.

Highlights for our fiscal year 2016

Finances

- We funded all operations, including $21.1 million of capital spending, from internal resources and remained debt free. All of our capital expenditures and dividends were funded solely by cash flow from operations and working capital and we ended our fiscal year with no funded debt.
- We returned $6.6 million to common shareholders in the form of cash dividends during fiscal 2016. We remain committed to our dividend policy and rewarding our long-term shareholders.
- We invested $1.2 million in our stock buyback program during fiscal 2016. We have up to $3.4 million remaining under this program.
- We increased working capital to $28.6 million at June 30, 2016 compared to $14.3 million at the prior year end. At June 30, 2016, working capital included $34.1 million of cash on hand.
- We entered into a new senior secured bank credit facility. The maximum borrowing base is $50.0 million; however the initial borrowing base was set at $10.0 million. There are no outstanding borrowings.
- Our hedging program resulted in $3.4 million in net gains during fiscal 2016. In fiscal 2016, we used derivative instruments to reduce our exposure to oil price volatility in order to support the capital expenditures for the Delhi NGL plant and to protect our dividend policy. We have no hedges in place beyond September 30, 2016.

Operations

- Our fiscal 2016 net income to common shareholders was $24.0 million, a substantial increase from fiscal 2015 net income of $4.3 million. During fiscal 2016, litigation settlement proceeds, insurance proceeds and realized hedging gains contributed to significantly higher net income, offset in part by increased DD&A expenses, litigation expenses and higher income tax expense. This is our fifth consecutive year of reporting net income to common shareholders.

- We settled outstanding litigation with the operator of Delhi field. In the settlement, we received $27.5 million in cash and a working interest in the Mengel Sand, a separate interval within the Delhi field that is not currently producing. We also reached agreement on our ownership of the CO_2 recycle facility and on the long term costs of purchased CO_2.

- Installation and construction of the NGL recovery plant at Delhi is approximately 90% complete. Technical completion and start-up of the plant is scheduled to begin in November 2016. Our net share of capital expenditures for

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this project is $24.6 million, and has been funded through cash flow from operations and working capital. Approximately $3.1 million remains to be spent as of fiscal year end 2016.

- Our net oil production volumes at Delhi increased by over 46% year over year. Monthly production has been steadily increasing over the past year as a result of a conformance program and greater efficiency with the flood. The majority of the increase in our net production stems from the reversion of our 23.9% working interest and associated 19.0% revenue interest in the Delhi field which became effective on November 1, 2014. We had only eight months of working interest volumes in the prior fiscal year.

- We transferred our oilfield technology operations to a new entity and we expect annual cost reductions of approximately $1.0 million. We retained a minority equity interest in the new Company and will receive a 5% royalty on all future gross revenues from the technology. In addition, we have an option to increase our equity ownership and can use the technology in any of our operated wells.

Oil & Gas Reserves (based on SEC oil price of $40.91 per barrel in effect as at June 30, 2016)

- Delhi proved oil equivalent reserves at June 30, 2016 were 10.8 MMBOE, a 13% decline from the previous year. The Standardized Measure for proved reserves declined 51% to $78 million as a result of a 44% drop in the oil price from $72.55 to $40.91 per barrel. Proved reserves are 79% oil and 21% natural gas liquids, and 66% of these reserves are developed and producing.
- Delhi probable reserves at June 30, 2016 were 4.5 MMBOE, a 52% decrease over the previous year.
- Delhi possible reserves at June 30, 2016 were 2.7 MMBOE, a 10% decrease over the previous year.

The following table is a summary of our proved, probable and possible reserves for 2016 and 2015:

	Proved			Probable			Possible		
	2016	2015	Change	2016	2015	Change	2016	2015	Change
Reserves MMBOE	10.8	12.4	(13)%	4.5	9.3	(52)%	2.7	3.0	(10)%
% Developed	66 %	59 %	12 %	69 %	43 %	60 %	72 %	55 %	31 %
Liquids %	100 %	100 %	— %	100%	100%	— %	100%	100%	— %
Standardized Measure	$78	$159	(51)%						
PV-10* ($MM)	$101	$219	(54)%						

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

Projects

Additional property and project information is included under Item 1. Business, Item 2. Properties, Item 8. Financial Statements - Notes to the Financial Statements and Exhibit 99.4 of this Form 10-K.

Delhi Field EOR—Northeast Louisiana

Proved reserves volumes totaled 10.8 MMBOE with a Standardized Measure of $78 million and a PV-10* value of $101 million compared to the prior year's 12.4 MMBOE with a Standardized Measure of $159 million and a PV-10* value of $219

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million. Our reserves quantities in the Delhi field were generally consistent with expectations year over year, especially when applying to our long life production the 44% decline in SEC oil price at Delhi from $72.55 in the prior year to $40.91 in the current year. This decline in price led to a 13% decline in proved reserves volumes reflecting prior year production and removal of proved undeveloped reserves in Phase VI which were deemed to be uneconomic in the current price environment. Proved undeveloped reserves declined 1,422 MBOE to 3,655 MBOE as the result of a 1,091 MBOE negative revision due to the removal of Phase VI, the field's eastern most development site that is not deemed to be economic at current prices, a 154 MBOE negative revision in our remaining Phase V eastern area site and a 197 MBOE negative revision in NGL plant reserves, all three due to the reduced SEC oil price applied. The Phase VI eastern development patterns removed from our proved undeveloped reserves had significantly lower recoverable reserves and higher costs than the other Phase V eastern patterns we retained.

The reserves report reflects the conveyance, effective July 1, 2016, of a 0.2226% overriding royalty interest to the operator of Delhi as part of the litigation settlement agreement.

Our cost of purchased CO_2 in the Delhi field, the largest component of operating costs and the majority of our operating costs, is directly tied to the price of oil sold from the field. Therefore this major operating cost has dropped commensurate with the price of crude. Also, we have been successful in realizing a substantial reduction in aggregate CO_2 injection rate without impacting oil production rates. Gross injection rates for the year ended June 30, 2016 averaged 74 MMCF/D, a decline of 30% compared to the 106 MMCF/D during fiscal 2015 post-reversion period. We have also seen significant reductions in most categories of lease operating expenses, including decreased workover costs, lower power costs due to lower usage and lower contract labor and chemical costs. The combined effect of this has resulted in six sequential quarters of lower Delhi lifting costs per BOE from approximately $19 per BOE to approximately $12 per BOE.

Probable reserve volumes at Delhi were 4.5 MMBOE, compared to 9.3 MMBOE in the prior year. There were a number of projects included in probable reserves in the prior year which are not considered economic in the current price environment. A lesser portion of these revisions resulted from changes to the operators' long-term development plans for the field. Possible reserves volumes at Delhi were 2.7 MMBOE, compared to 3.0 MMBOE in the prior year.

Gross production at Delhi in the fourth quarter of fiscal 2016 was 6,964 barrels of oil per day (“BOPD”), up 1% from the third fiscal quarter’s 6,918 BOPD. Production volumes net to the Company were 1,841 BOPD and 1,829 BOPD, respectively. We expect production from the field to average approximately 7,000 BOPD until potential additional volumes are realized from the NGL recovery plant startup in late calendar 2016.

The construction and installation of the NGL plant is approximately 90% complete, with the plant startup scheduled to occur in November 2016. The plant has a total estimated cost of approximately $24.6 million net to Evolution, of which approximately $21.5 million had been incurred as of June 30, 2016. As previously discussed, the methane produced from the plant will be used to generate electricity and other power requirements for the field, which will substantially reduce operating costs. The NGL plant should also increase the efficiency of the CO_2 flood and is expected to result in incremental production of crude oil.

Remaining estimated capital expenditures amount to $8.12 per BOE for Phase V included in proved undeveloped reserves. Given the geology of the Delhi field, no remaining estimated capital expenditures are required to develop our probable or possible reserves as these reserves reflect incremental quantities associated with a greater percentage recovery of hydrocarbons in place than the recovery quantities assumed for proved reserves. Looking forward, the timing of plans for continued development of the eastern part of the Delhi field is dependent on the operator’s plans for capital allocation within their portfolio. We continue to believe that this high quality and economically viable project will be executed as planned, subject to oil price volatility.

GARP® - Artificial Lift Technology

As a result of a strategic review, Company management recommended and the Board approved a transfer of a majority interest in our GARP® oilfield technology operations to a new unaffiliated entity, led by our former SVP of Operations, who invented the technology, effective December 31, 2015. Evolution retained a minority equity interest in the new company and have the option to convert part of our funding into a substantially increased equity stake in the future. In addition, the Company retains a 5% royalty on all future gross revenues associated with the

GARP® technology. The three Evolution employees who had primary responsibilities for our GARP® operations, including our former SVP of Operations, a GARP® sales engineer and a field superintendent, have become full-time employees of the new company and have ceased to be employees of Evolution. The separation of this operation is expected to reduce the Company's ongoing general and administrative costs by approximately $1 million per year. The combined costs of severance and other related expenses resulted in a one-time restructuring charge in the second fiscal quarter ended December 31, 2015.

Other Fields

During fiscal 2016, we operated, produced and sold crude oil, natural gas and natural gas liquids from three legacy wells in the Giddings field area in central Texas. Due to declining production and depressed commodity prices, two wells have now been temporarily abandoned, and one well bore was returned to the previous operator per contractual agreement, as of August 2016. The financial impact of these wells were immaterial to our full year financial results. There are no current year reserves associated with these wells compared to 30 MBOE of proved reserves at June 30, 2015.

In October 2014, we closed on the sale of all of our remaining noncore mineral interests and assets in the Mississippi Lime project for cash proceeds of approximately $389,165, net of customary closing adjustments. This transaction completes the process of divesting of all of our non-core oil and gas properties. No reserves were associated with these assets as of June 30, 2015 or 2014.

Liquidity and Capital Resources

We have historically funded our operations through cash available from operations. Our primary sources of cash in fiscal 2016 were from funds generated from the sale of oil and natural gas production and the litigation settlement. A portion of these cash flows were used to fund our capital expenditures. While we will continue to develop our properties near term, such development will be more limited while commodity prices remain low and unstable. The Company will manage any development activity in the context of its operating cash flow and existing working capital.

On April 11, 2016, the Company entered into a new credit agreement with MidFirst Bank (the "Facility"). The Facility replaces the Company's previous unsecured credit facility which was set to expire on April 29, 2016 and was terminated in early April. The Facility provides a senior secured revolving credit facility with an initial borrowing base of $10.0 million (the "Borrowing Base") and a maximum borrowing amount of $50.0 million. The Facility matures on April 11, 2019, and is secured by substantially all of the Company's assets.

The Borrowing Base is subject to periodic redeterminations and further adjustments from time to time. The Borrowing Base will be redetermined semi-annually on each May 15 and November 15, beginning November 15, 2016. The Borrowing Base will also be reduced in certain circumstances such as the sale or disposition of certain oil and gas properties of the Company or its subsidiaries and cancellation of certain hedging positions. With the recent volatility in commodity prices, our borrowing base and related commitments under the Facility could be reduced in the future.

The Facility allows for Eurodollar Loans and Base Rate Loans, each as defined in the Facility. The interest rate on each Eurodollar Loan will be the lesser of (1) the adjusted LIBOR for the applicable interest period plus 275 basis points or (2) the Maximum Rate, as defined. The annual interest rate on each Base Rate Loan is the lesser of (1) the Prime Rate plus 100 basis points or (2) the Maximum Rate.

The Facility contains certain covenants, which, among other things, require the maintenance of (i) a total leverage ratio of not more than 3.0 to 1.0, (ii) a debt service coverage ratio of not less than 1.1 to 1.0 and (iii) a consolidated tangible net worth of not less than $40 million, each as defined in the Facility. The Facility also contains other affirmative and negative covenants and events of default. As of June 30, 2016, the Company was in compliance with all covenants contained in the Facility, and no amounts were outstanding under the Facility.

We had $34.1 million and $20.1 million in cash and cash equivalents at June 30, 2016 and June 30, 2015, respectively.

During our fiscal year ended June 30, 2016, we financed our operations and capital spending with net cash generated from operations and cash on hand. At June 30, 2016, our working capital was $28.6 million, compared to working capital of $14.4 million at June 30, 2015. The $14.2 million working capital increase is primarily due to a $13.9 million increase in cash.

Cash Flows from Operating Activities

For the year ended June 30, 2016, cash flows provided by operating activities were $30.7 million, reflecting $28.9 million provided by operations before $1.8 million provided by other working capital changes. Of the $28.9 million provided before working capital changes, approximately $24.7 million resulted from net income and $4.2 million was attributable to non-cash expenses and gains.

For the year ended June 30, 2015, cash flows provided by operating activities were $10.4 million, reflecting $10.9 million provided by operations before $0.5 million used by other working capital changes. Of the $10.9 million provided before working capital changes, approximately $5.0 million resulted from net income and $5.9 million was attributable to non-cash expenses.

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

Cash Flows from Investing Activities

For the year ended June 30, 2016, investing activities used $17.6 million of cash, consisting primarily of capital expenditures of approximately $21.1 million for Delhi field partially offset by $3.7 million of derivative settlement payments received.

For the year ended June 30, 2015, investing activities used $5.0 million of cash, consisting primarily of capital expenditures of approximately $4.9 million for Delhi field, $0.3 million for artificial lift technology together with $0.2 million of other assets comprised primarily of GARP® patent costs, partially offset by $0.4 million of proceeds received for the sale of properties in the Mississippi Lime project in October 2014.

For the year ended June 30, 2014, cash paid for oil and gas capital expenditures was $1.3 million, primarily for development activities related to GARP® wells in Giddings and continuing costs for wells drilled in the Mississippi Lime during the prior year. We received approximately $0.5 million of proceeds from asset sales, including $0.4 million from the December sale of our South Texas properties, and $0.3 million of cash from the maturity of a certificate of deposit.

Oil and gas capital expenditures incurred, which includes accrued expenditures and other noncash items, were $19.7 million, $11.2 million, and $1.2 million, respectively, for the years ended June 30, 2016, 2015, and 2014. These amounts can be reconciled to cash capital expenditures on their respective cash flow statements by adjusting them for related non-cash items presented at Note 13 - Supplemental Cash Flow Information.

Cash Flows from Financing Activities

For the year ended June 30, 2016, financing activities provided $0.9 million of cash from $9.6 million of tax benefits related to stock-based compensation partially offset by $7.2 million of dividend payments to common and preferred shareholders and $1.4 million of treasury stock acquisitions primarily attributable to the Company's share buyback program. The tax benefits included a $1.5 million cash refund received from the State of Louisiana for carryback of stock-based compensation deductions to previously filed returns.

During the year ended June 30, 2015, we used $9.2 million in cash for financing activities, reflecting $9.8 million of common stock dividend payments, $0.7 million of preferred stock dividends and $0.3 million of treasury stock acquired through the surrender of shares by certain officers and employees in satisfaction of payroll liabilities related to stock-based compensation and open market purchases under our stock repurchase program, partially offset by cash inflows of $1.6 million from a tax benefit related to stock-based compensation and $0.1 million from stock option exercises.

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

Capital Budget

Delhi Field

During fiscal 2016, our net share of capital expenditures was approximately $19.0 million, all which was incurred at Delhi and primarily for the NGL plant. There have been and will continue to be recurring maintenance capital expenditures required for a field of this size. These expenditures are generally for testing and strengthening of well bore integrity, including previously plugged wells, drilling and completion of monitoring wells and larger projects to recomplete or workover wells which may be capitalized instead of being charged to operating expenses.

Known capital expenditures over the next fiscal year are expected to total approximately $3.1 million, net to our working interest, primarily for the remaining costs of the NGL plant. There will likely be additional maintenance capital expenditures, but the amount of these is not expected to be material to our financial position and cannot be estimated accurately at this time.

After completion of the NGL plant, there are two remaining capital projects to exploit the eastern part of the Delhi field. The first phase of this project was underway in the fall of 2014, immediately after reversion of our working interest. However, based on the decline in oil prices, the operator significantly reduced its capital budget and suspended work on this phase. The resumption of this project is dependent on prevailing oil prices, the availability of capital for such projects and the relative economics of this project versus other projects in the operator's portfolio. We believe this Phase V project, which has an estimated cost of $11.5 million net to our working interest, has favorable economics, even in this lower price environment, and expect the expansion of the CO_2 flood to resume within the next two years. Phase VI has less favorable economics and will require a significant increase in oil prices or other improvements to the economics of the project before it is expected to move forward. The economics of both projects will be improved subsequent to the completion and startup of the NGL recovery plant in late calendar 2016.

Liquidity Outlook

Our current liquidity position is very strong, with $28.6 million of working capital, which is significantly in excess of our expected capital needs and we also expect positive cash flow in the future. Our future liquidity will be impacted by changes in the realized prices we receive for the oil, natural gas and natural gas liquids we produce and the costs associated with that production. Commodity prices are market driven and historically volatile, and they are likely to continue to be volatile. In June 2015, the Company began using derivative instruments to reduce its exposure to oil price volatility for a portion of its near-term forecasted production in order to achieve a more predictable level of cash flows to support the Company's capital expenditure and dividend programs. Costless collars and swaps used by the Company to manage risk are designed to establish floor prices on anticipated future oil production. While the use of these derivative instruments limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. Our future revenues, cash flow, profitability, access to capital and future rate of growth are significantly impacted by the prices we receive for our production.

Funding for our anticipated capital expenditures over the next two fiscal years is expected to be met from cash flows from operations and current working capital. Our preference is to remain debt free under our current operating plans, but we have access to a senior secured credit facility for oil and gas development as required. In addition we have an effective shelf registration statement with Securities and Exchange Commission. We may choose to evaluate new growth opportunities through acquisitions or other transactions. In that event, we would expect to use our internal resources of cash, working capital and borrowing capacity under our credit facility. It may also be advantageous for us to consider issuing additional equity as part of any potential transaction, but we have no specific plans to do so at this time.

The Board of Directors instituted a cash dividend on our common stock in December 2013 and have since paid eleven consecutive quarterly dividends and have declared the twelfth dividend for payment on September 30, 2016. In addition, in May 2015, we established a stock repurchase plan to allow us acquire up to $5.0 million of our common stock over time. During fiscal 2016, we spent $1.2 million on stock repurchases. Return of free cash flow in excess of our operating and capital requirements to our shareholders through cash dividends and repurchases of our common stock remains a priority of our financial strategy, and it is our near term goal to increase our dividends over time as appropriate.

Results of Operations

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

	Year Ended June 30,		
	2016	2015	2014
Oil and gas production:			
Crude oil revenues	$26,130,762	$27,761,291	$17,460,392
NGL revenues	7,885	37,227	117,166
Natural gas revenues	2,895	26,601	95,950
Total revenues	$26,141,542	$27,825,119	$17,673,508
Crude oil volumes (Bbl)	658,041	450,713	169,783
NGL volumes (Bbl)	491	1,358	3,516
Natural gas volumes (Mcf)	1,620	7,981	26,655
Equivalent volumes (BOE)	658,802	453,401	177,742
Equivalent volumes per day (BOE/D)	1,800	1,242	487
Crude oil price per Bbl	$39.71	$61.59	$102.84
NGL price per Bbl	16.06	27.41	33.32
Natural gas price per Mcf	1.79	3.33	3.60
Equivalent price per BOE	$39.68	$61.37	$99.43
Production costs (a)	$9,062,179	$9,335,244	$1,193,573
Production costs per BOE	$13.76	$20.59	$6.72
Oil and gas DD&A (b)	$4,906,123	$3,220,990	$1,192,370
Oil and gas DD&A per BOE	$7.45	$7.10	$6.71
Artificial lift technology services:			
Services revenues	$207,960	$16,146	$—
Cost of service	70,932	20,369	—
Depreciation and amortization expense	$238,475	$374,371	$—

(a) Includes ad valorem and production taxes of $294,689, $49,848, and $44,599 in for the years ended June 30, 2016, 2015, and 2014, respectively.

(b) Excludes depreciation and amortization expense of artificial lift technology services below and excludes non-operating asset depreciation of $20,522, $20,376, and $36,315 for the years ended June 30, 2016, 2015, and 2014, respectively.

Year ended June 30, 2016 compared with the Year ended June 30, 2015

Net Income Available to Common Stockholders. For the year ended June 30, 2016, we generated net income to common shareholders of $24.0 million, or $0.73 per diluted share, on total revenues of $26.3 million. This compares to net income of $4.3 million, or $0.13 per diluted share, on total revenues of $27.8 million for the year-ago period. The $19.7 million earnings increase resulted from $28.1 million from the Delhi field litigation settlement, $1.1 million from an insurance recovery, and $3.5 million of derivative gains, partially offset by $6.1 million of higher income taxes, $1.5 million of lower revenue, and $5.4 million of higher operating expenses (which includes a $1.3 million non-recurring restructuring charge).

Oil and Gas Production. Revenues decreased $1.7 million to $26.1 million primarily as a result of a 35% decline in realized prices from $61.37 per equivalent barrel in the year-ago period to $39.68 per barrel in the current period, partially offset by a 45% increase in production volumes. The year-ago period did not include a full twelve months of net production and revenues or production costs as reversion of our working interest did not occur until November 1, 2014. Delhi oil production and revenues comprise virtually all of our revenues. Delhi gross production of 6,778 BOPD was 12% higher that the average gross production of 6,038 BOPD in the year-ago period as a result of production enhancement and conformance operations in the field.

Production Costs. Production costs for the current period decreased $0.2 million to $9.1 million from $9.3 million in the prior year period due to a $0.6 million decrease for the Company's operated wells as a result of workover expense in the prior year, partially offset by $0.4 million increase at the Delhi field. The year-ago period did not include a full twelve months of net production costs as reversion of our Delhi working interest did not occur until November 1, 2014. Delhi production costs for the current period were $8.9 million of which $4.1 million was for CO_2 costs, compared to $8.5 million, of which $5.1 million was for CO_2 costs, in the year-ago period. Average gross injection volumes decreased from 105,848 Mcf per day in the post-reversion prior year period to 73,762 Mcf per day for the year ended June 30, 2016. For the year ended June 30, 2016, production costs were $13.76 per BOE on total production volumes. Production costs were $18.90 per BOE calculated solely on our Delhi working interest volumes, which includes $8.66 per working interest BOE for CO_2 costs. These latter production costs per BOE exclude production volumes from our royalty interests in the Delhi field, which bear no production costs, and are therefore higher than the rates per BOE on our total production volumes.

Artificial Lift Technology Services. Service revenues were $0.2 million for the year ended June 30, 2016 as a result of current year installations at third party wells. Prior year service revenues and costs were negligible.

Cost of Artificial Lift Technology Services. Cost of technology services were $0.1 million for the year ended June 30, 2016 as a result of current year project activity.

General and Administrative Expenses (“G&A”). G&A expenses increased $2.8 million, or 45%, to $9.1 million for the year ended June 30, 2016 from the year-ago period, as a result of a $1.7 million increase in litigation costs and $0.8 million of stock compensation expense. Total litigation costs for the current year were approximately $2.7 million. In June, 2016, we relocated our office to substantially smaller and less expensive premises. This cost savings will be reflected in future operations.

Restructuring charge. Effective December 31, 2015, we recognized a $1.3 million restructuring charge related to the separation of our GARP® artificial lift technology operations. Approximately $0.6 million of the charge consists of the impairment of assets used in that operation and $0.6 million was associated with accrued personnel termination costs to be paid from January 2016 through June 2017. Such termination costs also include approximately $0.1 million of non-cash stock compensation expense from the accelerated vesting of restricted stock. As a result of the restructuring, future annual overhead cost savings are estimated to be approximately $1.0 million per year.

Other Income and Expenses. During the year ended June 30, 2016, the Company realized gains of $28.1 million from the Delhi field litigation settlement, $3.4 million of gains on derivatives and $1.1 million from an insurance recovery at the Delhi field.

Depletion & Amortization Expense (“DD&A”). DD&A increased $1.5 million, or 43% to $5.2 million for the current period compared to $3.6 million for the year-ago period as a result of $1.7 million of higher amortization of the full cost pool, partially offset by $0.1 million of lower depreciation on artificial lift technology. Compared to the prior year, production volumes increased 45% to 0.7 million BOE and the amortization rate increased 5% to $7.45 per BOE. Compared to the prior year, the higher amortization rate was due to an 18% decrease in our pool of unamortized costs, partially offset by a 13% decline in proved reserves BOE.

Year ended June 30, 2015 compared with the Year ended June 30, 2014

Net Income Available to Common Shareholders. For the year ended June 30, 2015, we generated net income of $4.3 million or $0.13 per diluted share on total revenues of $27.8 million. This compares to net income of $2.9 million, or $0.09 per diluted share, on total revenues of $17.7 million for the prior fiscal year. Earnings increased by $1.4 million, reflecting $10.2 million of higher revenue together with $2.1 million of lower G&A and $1.3 million of restructuring expenses in the prior year, partially offset by $8.1 million of higher production costs, $2.4 million of increased DD&A and $1.6 million of higher income taxes.

Oil and Gas Production. Revenues increased to $27.8 million primarily as a result of a 155% increase in production volumes from the prior fiscal year due to the November 1, 2014 reversion of our Delhi working interest, partially offset by a 38% decline in realized prices from $99.43 per equivalent barrel to $61.37 per barrel in the current period. Delhi oil production and revenues comprise virtually all of our fiscal 2015 revenues. The $10.2 million revenue increase was due to a $10.7 million increase at Delhi, offset by a $0.5 million decline at our operated properties reflecting previous Mississippi Lime and South Texas divestitures. Delhi gross production decreased 0.6% from 6,078 BOPD in the prior year to 6,038 BOPD in the current year.

Production Costs. Production costs for the current period increased $ 8.1 million to $9.3 million from $1.2 million in the prior year period due to a $8.5 million increase at the Delhi field, partially offset by a $0.4 million decrease for the Company's operated wells reflecting the divestitures of non core properties. There were no Delhi production costs in the prior fiscal year as those revenues were derived solely from our mineral and overriding royalty interests, which bear no operating expenses. The current period does not include a full twelve months of net production costs as reversion of our Delhi working interest did not occur until November 1, 2014. Of the $8.5 million of Delhi production costs incurred in the current year, $5.1 million was for CO2 costs. For the year end June 30, 2015, production costs were $20.59 per BOE on total production volumes. From our November 1, 2014 working interest reversion to June 30, 2015, production costs were $29.89 per BOE calculated solely on our Delhi working interest volumes, which includes $17.72 per working interest BOE for CO_2 costs. These latter production costs per BOE exclude production volumes from our royalty interests in the Delhi field, which bear no production costs, and are therefore higher than the rates per BOE on our total production volumes.

General and Administrative Expenses (“G&A”). G&A expenses decreased $2.1 million, or 25%, to $6.3 million during the year ended June 30, 2015 from $8.4 million in the prior year primarily due to fiscal 2014 non-recurring charges of $0.8 million related to stock option exercises and $0.6 million related to the retirement of our chief financial officer, a $0.6 million decrease in personnel-related costs as a result of our December 2013 restructuring, and a $0.7 million decline in accrued incentive compensation, partially offset by $0.4 million of higher legal expenses. This fiscal 2014 restructuring charge of $1.3 million consisted of $0.9 million of termination benefits and $0.4 million non-cash charge for accelerated restricted stock vesting for terminated employees.

Restructuring Charges. The Company recorded $1.3 million of restructuring expense in December 2013 primarily reflecting $956,000 of termination benefits to be paid from January to December 2014 and $376,000 of non-cash stock compensation expense for accelerated restricted stock vesting for terminated employees. All restructuring obligations had been satisfied by December 31, 2014. See Note 8 - Restructuring.

Depletion & Amortization Expense (“DD&A”). DD&A increased $2.4 million, or 194%, to $3.6 million for the year ended June 30, 2015 from $1.2 million for the prior year due to $2.0 million increase in amortization of our full cost oil and gas property cost pool and a $0.3 million impairment charge for GARP® equipment installations on three under performing wells of a third party customer. The remaining expense increase was primarily the result of higher depreciation of artificial lift equipment placed in service during fiscal 2015. The $2.0 million increase in full cost pool depletion was primarily due to higher volume generated from the reversionary working interest. For fiscal 2015 the depletion rate was $7.10 per BOE compared to $6.71 in the prior year. The increase in rate was impacted by a higher estimated cost for the Delhi field NGL plant at June 30, 2015.

Other Economic Factors

Inflation. Although the general inflation rate in the United States, as measured by the Consumer Price Index and the Producer Price Index, has been relatively low in recent years, the oil and gas industry has experienced unusually volatile price movements in commodity prices, vendor goods and oilfield services. Prices for drilling and oilfield services, oilfield equipment, tubulars, labor, expertise and other services greatly impact our lease operating expenses and our capital expenditures. During fiscal 2016, we have seen some declines in operating and capital costs as a result of lower demand and excess supply of good and services in the industry. Product prices, operating costs and development costs may not always move in tandem.

Known Trends and Uncertainties. General worldwide economic conditions, as well as economic conditions for the oil and gas industry specifically, 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 for oil gas decreases or there is a continuing excess supply in the future, it may put downward pressure on crude oil and natural gas prices, thereby lowering our revenues and working capital going forward.

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, 2016, we are obligated to make under our contractual obligations and commitments. We expect to fund these contractual obligations with cash on hand and cash generated from operations.

	Payments Due by Period				
	Total	Less than 1 Year	1 - 3 Years	3 - 5 Years	More than 5 Years
Contractual Obligations					
Operating lease	$220,292	$80,235	$140,057	—	—
Other Obligations					
Asset retirement obligations	962,196	201,896	—	—	760,300
Total obligations	$1,182,488	$282,131	$140,057	$ —	$760,300

As discussed at Note 6 – Property and Equipment, we have a $3.1 million capital expenditure commitment related to the completion of the NGL plant at the Delhi Field which we expect to fund in the first quarter of fiscal 2017.

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, 2016, we had no unevaluated properties costs.

Estimates of Proved Reserves. The estimated quantities of proved oil and natural gas reserves have a significant impact on the underlying financial statements. The estimated quantities of proved reserves are used to calculate depletion expense, and the estimated future net cash flows associated with those proved reserves is the basis in determining impairment under the quarterly ceiling test calculation. The process of estimating oil and natural gas reserves is very complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering and economic data. Estimated reserves are often subject to future revisions, which could be substantial, based on the availability of additional information, including reservoir performance, additional development activity, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that the reported reserve estimates represent the most accurate assessments possible, including the hiring of independent engineers to prepare our reserve estimates, the subjective decisions and variances in available data for the properties make these estimates generally less precise than other estimates included in our financial statements. Material revisions to reserve estimates and / or significant changes in commodity prices could substantially affect our estimated future net cash flows of our proved reserves, affecting our quarterly ceiling test calculation and could significantly affect our depletion rate. A 10% decrease in commodity prices used to determine our proved reserves and Standardized Measure as of June 30, 2016 would not have resulted in an impairment of our oil and natural gas properties. Holding all other factors constant, a reduction in the Company's proved reserve estimates at June 30, 2016 of 5%, 10% and 15% would affect depreciation, depletion and amortization expense by approximately $248,000, $524,000 and $831,000, respectively.

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

Valuation of Deferred Tax Assets. We make certain estimates and judgments in determining our income tax expense for financial reporting purposes. These estimates and judgments occur in the calculation of certain tax assets and liabilities that arise from differences in the timing and recognition of revenue and expense for tax and financial reporting purposes. Our federal and state income tax returns are generally not prepared or filed before the consolidated financial statements are prepared or filed; therefore, we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits, and net operating loss carry backs and carry forwards. Adjustments related to these estimates are recorded in our tax provision in the period in which we file our income tax returns. Further, we must assess the likelihood that we will be able to recover or utilize our deferred tax assets (primarily our net operating loss). If recovery is not likely, we must record a valuation allowance against such deferred tax assets for the amount we would not expect to recover, which would result in an increase to our income tax expense. As of June 30, 2016, 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. 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, 2016.

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. We use derivative instruments to

manage our exposure to commodity price risk from time to time based on our assessment of such risk. We primarily utilize swaps and costless collars to reduct the effect of price changes on a portion of our future oil production. We do not enter into derivative instruments for trading purposes.

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

We have audited the accompanying consolidated balance sheets of Evolution Petroleum Corporation and subsidiaries (the "Company") as of June 30, 2016 and 2015, 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, 2016. 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 audits 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, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended June 30, 2016, 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, 2016, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013, and our report dated September 9, 2016 expressed an unqualified opinion on the effectiveness of Evolution Petroleum Corporation's internal control over financial reporting.

Hein & Associates LLP
Houston, Texas
September 9, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Evolution Petroleum Corporation

We have audited Evolution Petroleum Corporation's internal control over financial reporting as of June 30, 2016, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013. 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, 2016, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013.

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, 2016 and 2015, 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, 2016 and our report dated September 9, 2016 expressed an unqualified opinion.

Hein & Associates LLP
Houston, Texas
September 9, 2016

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Evolution Petroleum Corporation and Subsidiaries
Consolidated Balance Sheets

	June 30, 2016	June 30, 2015
Assets		
Current assets		
Cash and cash equivalents	$34,077,060	$20,118,757
Receivables	2,638,188	3,122,473
Deferred tax asset	105,321	82,414
Derivative assets, net	14,132	—
Prepaid expenses and other current assets	251,749	369,404
Total current assets	37,086,450	23,693,048
Property and equipment, net of depreciation, depletion, and amortization		
Oil and natural gas properties—full-cost method of accounting, of which none were excluded from amortization	59,970,463	45,186,886
Other property and equipment, net	28,649	276,756
Total property and equipment, net	59,999,112	45,463,642
Other assets	365,489	726,037
Total assets	$97,451,051	$69,882,727
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable	$5,809,107	$8,173,878
Accrued liabilities and other	2,097,951	855,373
Derivative liabilities, net	—	109,974
State and federal taxes payable	621,850	190,032
Total current liabilities	8,528,908	9,329,257
Long term liabilities		
Deferred income taxes	11,840,693	11,242,551
Asset retirement obligations	760,300	715,767
Deferred rent	—	18,575
Total liabilities	21,129,901	21,306,150
Commitments and contingencies (Note 18)		
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, 2016 and 2015, 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 and outstanding 32,907,863 and 32,845,205 shares as of June 30, 2016 and 2015, respectively	32,907	32,845
Additional paid-in capital	47,171,563	36,847,289
Retained earnings	29,116,363	11,696,126
Total stockholders' equity	76,321,150	48,576,577
Total liabilities and stockholders' equity	$97,451,051	$69,882,727

See accompanying notes to consolidated financial statements.

Evolution Petroleum Corporation and Subsidiaries
Consolidated Statements of Operations

	Years Ended June 30,		
	2016	2015	2014
Revenues			
Crude oil	$26,130,762	$27,761,291	$17,460,392
Natural gas liquids	7,885	37,227	117,166
Natural gas	2,895	26,601	95,950
Artificial lift technology services	207,960	16,146	—
Total revenues	26,349,502	27,841,265	17,673,508
Operating costs			
Production costs	9,062,179	9,335,244	1,193,573
Cost of artificial lift technology services	70,932	20,369	—
Depreciation, depletion and amortization	5,165,120	3,615,737	1,228,685
Accretion of discount on asset retirement obligations	49,054	34,866	41,626
General and administrative expenses*	9,079,597	6,256,783	8,388,291
Restructuring charges	1,257,433	(5,431)	1,293,186
Total operating costs	24,684,315	19,257,568	12,145,361
Income from operations	1,665,187	8,583,697	5,528,147
Other			
Gain on settled derivative instruments, net	3,315,123	—	—
Gain (loss) on unsettled derivative instruments, net	124,106	(109,974)	—
Delhi field litigation settlement	28,096,500	—	—
Delhi field insurance recovery related to pre-reversion event	1,074,957	—	—
Interest and other income	26,211	35,991	30,256
Interest (expense)	(70,943)	(73,636)	(69,092)
Income before income tax provision	34,231,141	8,436,078	5,489,311
Income tax provision	9,570,779	3,444,221	1,891,998
Net income attributable to the Company	24,660,362	4,991,857	3,597,313
Dividends on preferred stock	674,302	674,302	674,302
Net income attributable to common shareholders	$23,986,060	$4,317,555	$2,923,011
Earnings per common share			
Basic	$0.73	$0.13	$0.09
Diluted	$0.73	$0.13	$0.09
Weighted average number of common shares outstanding			
Basic	32,810,375	32,817,456	30,895,832
Diluted	32,861,231	32,924,018	32,564,067

* General and administrative expenses for the years ended June 30, 2016, 2015 and 2014 included non-cash stock-based compensation expense of $1,750,209, $943,653, and $1,352,322, respectively. These years also included litigation expenses of $2,729,755, $1,015,105, and $300,564, respectively.

See accompanying notes to consolidated financial statements.

Evolution Petroleum Corporation and Subsidiaries
Consolidated Statements of Cash Flows

	Years Ended June 30,		
	2016	2015	2014
Cash flows from operating activities			
Net income attributable to the Company	$24,660,362	$4,991,857	$3,597,313
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	5,211,494	3,664,373	1,272,778
Impairments included in restructuring charge	569,228	—	—
Stock-based compensation	1,750,209	943,653	1,352,322
Stock-based compensation related to restructuring	59,339	—	376,365
Accretion of discount on asset retirement obligations	49,054	34,866	41,626
Settlement of asset retirement obligations	—	(223,564)	(315,952)
Deferred income taxes	575,235	1,422,489	1,344,812
Deferred rent	—	(17,145)	(17,145)
(Gain) loss on derivative instruments, net	(3,439,229)	109,974	—
Noncash (gain) on Delhi field litigation settlement	(596,500)	—	—
Write-off of deferred loan costs	50,414	—	—
Changes in operating assets and liabilities:			
Receivables	484,285	(1,665,261)	507,592
Prepaid expenses and other current assets	24,754	378,049	(480,899)
Accounts payable and accrued expenses	822,730	551,452	663,645
Income taxes payable	431,818	190,032	(233,548)
Net cash provided by operating activities	30,653,193	10,380,775	8,108,909
Cash flows from investing activities			
Derivative settlements received	3,633,831	—	—
Proceeds from asset sales	—	398,242	542,347
Development of oil and natural gas properties	(21,095,901)	(4,890,909)	(966,931)
Acquisitions of oil and natural gas properties	—	—	(59,315)
Capital expenditures for technology and other equipment	(6,883)	(313,059)	(312,890)
Maturities of certificates of deposit	—	—	250,000
Other assets	(161,345)	(236,559)	(202,017)
Net cash used by investing activities	(17,630,298)	(5,042,285)	(748,806)
Cash flows from financing activities			
Proceeds from the exercise of stock options	51,000	141,600	3,252,801
Acquisitions of treasury stock	(1,357,185)	(333,841)	(1,655,251)
Common stock dividends paid	(6,565,823)	(9,833,642)	(9,723,833)
Preferred stock dividends paid	(674,302)	(674,302)	(674,302)
Deferred loan costs	(168,972)	(94,075)	(63,535)
Tax benefits related to stock-based compensation	9,650,657	1,633,946	509,096
Other	33	67	6,850
Net cash provided (used) by financing activities	935,408	(9,160,247)	(8,348,174)
Net increase (decrease) in cash and cash equivalents	13,958,303	(3,821,757)	(988,071)
Cash and cash equivalents, beginning of year	20,118,757	23,940,514	24,928,585
Cash and cash equivalents, end of year	$34,077,060	$20,118,757	$23,940,514

See accompanying notes to consolidated financial statements.

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Evolution Petroleum Corporation and Subsidiaries
Consolidated Statement of Changes in Stockholders' Equity
For the Years Ended June 30, 2016, 2015 and 2014

	Preferred		Common Stock					
	Shares	Par Value	Shares	Par Value	Additional Paid-in Capital	Retained Earnings	Treasury Stock	Total Stockholders' Equity
Balance, June 30, 2013	317,319	$ 317	28,608,969	$29,410	$31,813,239	$24,013,035	$(1,019,840)	$54,836,161
Issuance of restricted common stock	—	—	39,732	40	(40)	—	—	—
Exercise of warrants	—	—	905,391	905	(905)	—	—	—
Exercise of stock options	—	—	3,299,367	3,299	3,868,108	—	—	3,871,407
Forfeitures of restricted stock	—	—	(51,099)	(51)	51	—	—	—
Acquisition of treasury stock	—	—	(186,714)	—	—	—	(2,273,857)	(2,273,857)
Retirements of treasury stock	—	—	—	(988)	(3,292,709)	—	3,293,697	—
Stock-based compensation	—	—	—	—	1,728,687	—	—	1,728,687
Tax benefits related to stock-based compensation	—	—	—	—	509,096	—	—	509,096
Net income	—	—	—	—	—	3,597,313	—	3,597,313
Common stock cash dividends	—	—	—	—	—	(9,723,833)	—	(9,723,833)
Preferred stock cash dividends	—	—	—	—	—	(674,302)	—	(674,302)
Recovery of short swing profits	—	—	—	—	6,850	—	—	6,850
Balance, June 30, 2014	317,319	317	32,615,646	32,615	34,632,377	17,212,213	—	51,877,522
Issuance of restricted common stock	—	—	213,466	214	(147)	—	—	67
Exercise of stock options	—	—	87,000	87	141,513	—	—	141,600
Acquisition of treasury stock	—	—	(70,907)	—	—	—	(504,124)	(504,124)
Retirements of treasury stock	—	—	—	(71)	(504,053)	—	504,124	—
Stock-based compensation	—	—	—	—	943,653	—	—	943,653
	—	—	—	—	1,633,946	—	—	1,633,946

Tax benefits related to stock-based compensation								
Net income	—	—	—	—	—	4,991,857	—	4,991,857
Common stock cash dividends	—	—	—	—	—	(9,833,642)	—	(9,833,642)
Preferred stock cash dividends	—	—	—	—	—	(674,302)	—	(674,302)
Balance, June 30, 2015	317,319	317	32,845,205	32,845	36,847,289	11,696,126	—	48,576,577
Issuance of restricted common stock	—	—	272,098	272	(239)	—	—	33
Exercise of stock options	—	—	50,000	50	127,450	—	—	127,500
Forfeitures of restricted stock	—	—	(40,758)	(41)	41	—	—	—
Acquisition of treasury stock	—	—	(218,682)	—	—	—	(1,263,402)	(1,263,402)
Retirements of treasury stock	—	—	—	(219)	(1,263,183)	—	1,263,402	—
Stock-based compensation	—	—	—	—	1,809,548	—	—	1,809,548
Tax benefits related to stock-based compensation	—	—	—	—	9,650,657	—	—	9,650,657
Net income attributable to the Company	—	—	—	—	—	24,660,362	—	24,660,362
Common stock cash dividends	—	—	—	—	—	(6,565,823)	—	(6,565,823)
Preferred stock cash dividends	—	—	—	—	—	(674,302)	—	(674,302)
Balance, June 30, 2016	317,319	$ 317	32,907,863	$32,907	$47,171,563	$29,116,363	$—	$76,321,150

See accompanying notes to consolidated financial statements.

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EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 – Organization and Basis of Preparation
Nature of Operations. Evolution Petroleum Corporation ("EPM") and its subsidiaries (the "Company", "we", "our" or "us"), is an independent petroleum company headquartered in Houston, Texas and incorporated under the laws of the State of Nevada. We are engaged primarily in the development of oil and gas reserves within known oil and gas resources utilizing conventional and proprietary technology.
Principles of Consolidation and Reporting. Our consolidated financial statements include the accounts of EPM and its wholly-owned subsidiaries. All significant intercompany transactions have been eliminated in consolidation. The consolidated financial statements for the previous year include certain reclassifications that were made to conform to the current presentation. Such reclassifications have no impact on previously reported net income or stockholders' equity. As a result of the separation of our GARP® artificial lift technology operations discussed in Note 8, previously reported revenues for the Delhi field and our artificial lift technology operations have been reclassified as appropriate to crude oil, natural gas liquids, natural gas and artificial lift technology service revenues. Before the reclassification, artificial lift technology revenues included crude oil, natural gas liquids and gas revenues produced by certain of the Company's operated wells that utilized the technology, together with service revenues derived from the use of the Company's technology in third party wells. Previously reported production costs for our artificial lift technology operations have been reclassified as appropriate to oil and gas production costs and cost of artificial lift technology services.
Use of Estimates. The preparation of financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities at the dates of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Significant estimates include reserve quantities and estimated future cash flows associated with proved reserves, which significantly impact depletion expense and potential impairments of oil and natural gas properties, income taxes and the valuation of deferred tax assets, stock-based compensation and commitments and contingencies. We analyze our estimates based on historical experience and various other assumptions that we believe to be reasonable. While we believe that our estimates and assumptions used in preparation of the consolidated financial statements are appropriate, actual results could differ from those estimates.
Note 2 – Summary of Significant Accounting Policies
Cash and Cash Equivalents. We consider all highly liquid investments, with original maturities of 90 days or less when purchased, to be cash and cash equivalents.
Account Receivable and Allowance for Doubtful Accounts. Accounts receivable consist of joint interest owner obligations due within 30 days of the invoice date, accrued revenues due under normal trade terms, generally requiring payment within 30 days of production, and other miscellaneous receivables. No interest is charged on past-due balances. Payments made on accounts receivable are applied to the earliest unpaid items. We establish provisions for losses on accounts receivables if it is determined that collection of all or a part of an outstanding balance is not probable. Collectibility is reviewed regularly and an allowance is established or adjusted, as necessary, using the specific identification method. As of June 30, 2016 and 2015, no allowance for doubtful accounts was considered necessary.
Oil and Natural Gas Properties. We use the full cost method of accounting for our investments in oil and natural gas properties. Under this method of accounting, all costs incurred in the acquisition, exploration and development of oil and natural gas properties, including unproductive wells, are capitalized. This includes any internal costs that are directly related to property acquisition, exploration and development activities but does not include any costs related to production, general corporate overhead or similar activities. Gain or loss on the sale or other disposition of oil and natural gas properties is not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves.

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

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

Limitation on Capitalized Costs. Under the full-cost method of accounting, we are required, at the end of each fiscal quarter, to perform a test to determine the limit on the book value of our oil and natural gas properties (the "Ceiling Test"). If the capitalized costs of our oil and natural gas properties, net of accumulated amortization and related deferred income taxes, exceed the "Ceiling", this excess or impairment is charged to expense and reflected as additional accumulated depreciation, depletion and amortization or as a credit to oil and natural gas properties. The expense may not be reversed in future periods, even though higher oil and natural gas prices may subsequently increase the Ceiling. The Ceiling is defined as the sum of: (a) the present value, discounted at 10 percent, and assuming continuation of existing economic conditions, of 1) estimated future gross revenues from proved reserves, which is computed using oil and natural gas prices determined as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period (with consideration of price changes only to the extent provided by contractual arrangements including hedging arrangements pursuant to SAB 103), less 2) estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves; plus (b) the cost of properties not being amortized (pursuant to Reg. S-X Rule 4-10 (c)(3)(ii)); plus (c) the lower of cost or estimated fair value of unproven properties included in the costs being amortized; net of (d) the related tax effects related to the difference between the book and tax basis of our oil and natural gas properties. Our Ceiling Tests did not result in an impairment of our oil and natural gas properties during the years ended June 30, 2016, 2015 or 2014.
Other Property and Equipment. Other property and equipment includes leasehold improvements, data processing and telecommunications equipment, office furniture and equipment, and oilfield service equipment related to our artificial lift technology operations. These items are recorded at cost and depreciated over expected lives of the individual assets or group of assets, which range from three to seven years. The assets are depreciated using the straight-line method, except for oilfield service equipment related to our artificial lift technology operations, which is depreciated using a method which approximates the timing and amounts of expected revenues from the contract. Realization of the carrying value of other property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Assets are determined to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset, including disposal value, if any, is less than the carrying amount of the asset. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. Repairs and maintenance costs are expensed in the period incurred.
Deferred Financing Costs. The Company capitalizes costs incurred in connection with obtaining financing. These costs are included in other assets on the Company's consolidated balance sheet and are amortized over the term of the related financing using the straight-line method, which approximates the effective interest method.
Asset Retirement Obligations. An asset retirement obligation associated with the retirement of a tangible long-lived asset is recognized as a liability in the period incurred, with an associated increase in the carrying amount of the related long-lived asset, our oil and natural gas properties. The cost of the tangible asset, including the asset retirement cost, is depleted over the useful life of the asset. The initial recognition or subsequent revision of asset retirement cost is considered a level 3 fair value measurement. The asset retirement obligation is recorded at its estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligation discounted at our credit-adjusted risk-free interest rate. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value. If the estimated future cost of the asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the long-lived asset. Revisions to estimated asset retirement obligations can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimated timing of abandonment.
Fair Value of Financial Instruments. Our financial instruments consist of cash and cash equivalents, certificates of deposit, accounts receivable, accounts payable and derivative instruments. Except for derivatives, the carrying amounts of these approximate fair value due to the highly liquid nature of these short-term instruments. The fair

values of the Company’s derivative assets and liabilities are based on a third-party industry-standard pricing model that uses market data obtained from third-party sources, including quoted forward prices for oil and gas, discount rates and volatility factors.

Stock-based Compensation. Estimated grant date fair value of stock-based compensation awards is determined to provide the basis for future compensation expense. Service-and performance-based Restricted Stock and Contingent Restricted Stock awards are valued using the market price of our common stock on the grant date. For market-based awards, which reflect future returns of our common stock, the fair value and expected vesting period are determined using a Monte Carlo simulation based on the historical volatility of the Company's total return compared to the historical volatilities of the other companies comprising a benchmark index. We used the Black-Scholes option-pricing model to determine grant date fair value of our past Stock Option and Incentive Warrant awards. For service-based awards stock-based compensation equal to grant date fair value is recognized ratably over the requisite service period as the award vests. A performance-based award vests upon attaining the award's operational goal and requires that the recipient remain an employee of the Company upon vesting. Stock-based compensation expense equal to grant date fair value is recognized ratably over the expected vesting period when it is deemed probable, for accounting purposes, that the performance goal will be achieved. The expected vesting period may be deemed to be shorter than the remainder of the award’s term. For a market-based award stock-based compensation expense equal to grant date fair value is recognized ratably over the expected vesting period, so long as the award holder remains an employee of the Company. Total compensation expense is independent of vesting or expiration of the awards, except for termination of service.

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

Revenue Recognition - Artificial Lift Technology. Our artificial lift technology operations have generated revenues under contractual arrangements. Under these contracts, we were required to bear part or all of the incremental installation and capital costs for the technology. We evaluated the substance of each contractual arrangement and recognized revenues over the life of the contract as the earnings process is determined to be complete. We likewise charge our costs, including both capital expenditures and operating expenses, to operating costs in a manner which either matches these costs to the timing of expected revenues, where appropriate, or charges these costs to the accounting period in which they were incurred where it is not appropriate to capitalize or defer them to match with revenues.

Derivative Instruments. The Company uses derivative transactions to reduce its exposure to oil price volatility. All derivative instruments are recorded on the consolidated balance sheet as either an asset or liability measured at fair value. The Company nets its derivative instrument fair value amounts executed with the same counterparty pursuant to a ISDA master agreement, which provides for net settlement over the term of the contract and in the event of default or termination of the contract. Although the derivative instruments provide an economic hedge of the Company’s exposure to commodity price volatility, because the Company elected not to meet the criteria to qualify its derivative instruments for hedge accounting treatment, net gains and losses as a result of changes in the fair value of derivative instruments are recognized as gain or (loss) on derivatives in the consolidated statements of operations in the period in which the changes occur. The net cash flows resulting from the payments to and receipts from the counterparty as a result of derivative settlements are classified as cash flows from investing activities. The Company does not intend to enter into derivative instruments for speculative or trading purposes.

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, consisting of leasehold improvements, office and computer equipment, vehicles and artificial lift equipment is depreciated as described above in Other Property and Equipment.

Intangible Assets - Intellectual Property. The Company has capitalized the external costs, consisting primarily of legal costs, related to securing its patents and trademarks. The costs related to patents were amortized over the remaining patent life which was less than the expected useful life of each patent. Trademarks have a perpetual life and were not amortized.

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. 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 contingent 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. Potentially dilutive common shares are excluded from the computation if their effect is anti-dilutive.
Recent Accounting Pronouncements.
In August 2015, the FASB issued Accounting Standards Update 2015-14, which defers the effective date of ASU 2014-09 Revenue from Contracts with Customers (Topic 606) (" ASU 2014-09") one year, and would allow entities the option to early adopt the new revenue standard as of the original effective date. Issued in May 2014, ASU 2014-09 provided guidance on revenue recognition on contracts with customers to transfer goods or services or on contracts for the transfer of nonfinancial assets. ASU 2014-09 requires that revenue recognition on contracts with customers depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. For public companies, ASU 2014-09 would have been effective for fiscal years, and interim periods within those years, beginning after December 15, 2017. The standard provided for either the retrospective or cumulative effect transition method. The Company is currently assessing the impact of the adoption of ASU 2014-09 will have on its consolidated financial statements, if any.
In November 2015, the FASB issued ASU No. 2015-17, “Balance Sheet Classification of Deferred Taxes” as part of their simplification initiatives. The standard requires that deferred tax liabilities and assets be classified as noncurrent in a classified statement of financial position. The update is effective for public company annual reporting periods beginning after December 15, 2016, and may be adopted prospectively or retrospectively with early adoption permitted. The Company plans to early adopt this standard the first quarter of year ended June 30, 2017 and does not believe that adoption of this update will have a material impact on our results of operations, financial position or cash flows.

On February 25, 2016, the FASB issued ASU 2016-02, Leases (“ASU 2016-02”), which relates to the accounting for leasing transactions. This standard requires a lessee to record on the balance sheet the assets and liabilities for the rights and obligations created by leases with lease terms of more than 12 months. In addition, this standard requires both lessees and lessors to disclose certain key information about lease transactions. This standard will be effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. We are evaluating the impact the adoption of ASU 2016-02 will have on our condensed consolidated financial statements.

On March 30, 2016, the FASB issued ASU 2016-09, Compensation - Stock Compensation: Improvements to Employee Share-Based Payment Accounting (“ASU 2016-09”), which relates to the accounting for employee share-based payments. This standard addresses several aspects of the accounting for share-based payment award transactions, including: (a) income tax consequences; (b) classification of awards as either equity or liabilities; and (c) classification on the statement of cash flows. This standard will be effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years. The Company plans to early adopt this standard during the first quarter of the year ended June 30, 2017. The adoption of this standard will result in all excess tax benefits or deficiencies being recognized as tax expense or benefit in the reporting period they occur regardless of whether the benefit reduces taxes payable in the current period. On the statement of cash flows excess tax benefits or deficiencies will be classified along with other income tax as an operating activity and cash paid by the Company when directly withholding shares for tax withholding purposes will continue to be classified as a financing activity. The Company is in the process of evaluating the impact of this accounting standard on its consolidated financial statements, but does not expect the impact of adoption to be material.

Note 3 – Delhi Field Litigation Settlement

On June 24, 2016, Evolution Petroleum Corporation, together with its subsidiaries NGS Sub Corp. and Tertiaire Resources Company (collectively, “Evolution”), entered into a settlement agreement with Denbury Resources, Inc. and Denbury Onshore, LLC, a subsidiary of Denbury Resources Inc. (together with Denbury Onshore, "Denbury"), to resolve all outstanding disputes and claims between the parties, including claims related to the litigation between Evolution and Denbury with respect to the Delhi field in northeastern Louisiana. The Delhi field litigation between the parties has been dismissed by the Court with prejudice. In connection with this settlement, the Company recognized a $28.1 million settlement gain consisting of a $27.5 million cash payment made by Denbury together with its conveyance to Evolution of a 23.9% working interest in the Mengel Sand Interval, a separate interval within the boundaries of the Delhi field which is not currently producing and for which we estimated a Level 2 fair value of $596,500. In addition, effective July 1, 2016, Denbury will be credited with an additional 0.2226% overriding royalty interest in the Delhi field to remedy a previous dispute regarding the interests conveyed in the original transaction between the parties. See Note 18 — Commitments and Contingencies.

Note 4 – Receivables

As of June 30, 2016 and June 30, 2015 our receivables consisted of the following:

	June 30, 2016	June 30, 2015
Receivables from oil and gas sales	$2,637,593	$3,122,155
Other	595	318
Total receivables	$2,638,188	$3,122,473

Note 5 – Prepaid Expenses and Other Current Assets

As of June 30, 2016 and June 30, 2015 our prepaid expenses and other current assets consisted of the following:

	June 30, 2016	June 30, 2015
Prepaid insurance	$168,681	$178,994
Prepaid federal and state income taxes	—	22,542
Equipment inventory (a)	—	81,538
Retainers and deposits	30,568	26,978
Other prepaid expenses	52,500	59,352
Prepaid expenses and other current assets	$251,749	$369,404

(a) As discussed in Note 8, our equipment inventory was determined to have no future value in use for our operations and negligible market value and was charged to restructuring costs as part of the separation of our artificial lift technology operations.

Note 6 – Property and Equipment

As of June 30, 2016 and June 30, 2015, our oil and natural gas properties and other property and equipment consisted of the following:

	June 30, 2016	June 30, 2015
Oil and natural gas properties:		
Property costs subject to amortization	$77,408,353	$57,718,653
Less: Accumulated depreciation, depletion, and amortization	(17,437,890)	(12,531,767)
Unproved properties not subject to amortization	—	—
Oil and natural gas properties, net	59,970,463	45,186,886
Other property and equipment:		
Furniture, fixtures and office equipment, at cost	228,752	287,680
Artificial lift technology equipment, at cost	7,000	319,994
Less: Accumulated depreciation	(207,103)	(330,918)
Other property and equipment, net	$28,649	$276,756

As of June 30, 2016 and 2015, all oil and gas property costs were being amortized.

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During the year ended June 30, 2016, the Company incurred capital expenditures of $19.0 million for the Delhi field, including approximately $16.4 million for the NGL plant project which is currently under construction. We have incurred $21.5 million on a cumulative basis for the NGL plant out of a total authorized commitment of $24.6 million, with a remaining balance of approximately $3.1 million.

As described in Note 3 – Delhi Field Litigation Settlement, we received a 23.9% working interest in the Mengel Interval (currently non-producing) having an estimated fair value of $596,500.

On December 31, 2015, as described in Note 8 — Restructuring, we transferred our residual artificial lift technology equipment to new entity not controlled by the Company. We recorded a charge of $210,392 to expense most of the remaining capitalized costs of artificial lift equipment installed in the wells of a third-party customer. Under our installation contracts, we had funded the majority of the incremental equipment and installation costs in exchange for 25% of the net profits from production, as defined, for as long as the technology remains in the wells. During the year ended ended June 30, 2015, we incurred $217,733 of costs related to installing our artificial lift technology on third party wells and recorded an impairment charge of $275,682 reflecting the unrecovered installation costs, net of estimated salvage value. During the year ended June 30, 2014, we incurred $377,943 of installation costs. Impairment charges are included in depreciation, depletion and amortization expense on the consolidated statement of operations. On October 24, 2014, we sold all of our remaining mineral interest and assets in the Mississippi Lime project for proceeds of $389,165 and the buyer's assumption of all abandonment liabilities. On December 1, 2013, we sold our producing assets and undeveloped reserves in the Lopez Field in South Texas in return for proceeds of $402,500 and the buyer's assumption of all abandonment liabilities. The net proceeds from these sales of our properties, including the reduction of asset retirement obligations, were recognized as a reduction of the cost of oil and gas properties.

Note 7 – Other Assets

As of June 30, 2016 and June 30, 2015 our other assets consisted of the following:

	June 30, 2016	June 30, 2015
Royalty rights	108,512	—
Less: Accumulated amortization of royalty rights	(6,782)	—
Investment in Well Lift Inc., at cost	108,750	—
Deferred loan costs	168,972	337,078
Less: Accumulated amortization of deferred loan costs	(13,963)	(147,057)
Trademarks	—	44,803
Patent costs	—	538,276
Less: Accumulated amortization of patent costs	—	(47,063)
Other assets, net	$365,489	$726,037

During the year ended June 30, 2016, our previous negotiations to obtain a new expanded secured credit facility were curtailed due to market conditions. As a result, the Company determined that $50,414 of deferred legal fees related to the proposed facility were unlikely to be utilized and were charged to expense. In addition, $107,196 of deferred costs incurred for title work in the Delhi field was charged to capitalized costs of oil and gas properties. Our existing unsecured credit facility expired in April 2016 and its associated deferred loan costs of $179,468 had been completely amortized. Contemporaneous with that facility's expiration, we entered into a secured credit facility provided by another financial institution, incurring $168,972 of deferred loan costs. Total amortization of costs related to our credit facilities for the year ended June 30, 2016 was $46,374.

See Note 8 – Restructuring for discussion of transactions associated with the separation of our artificial lift technology operations.

The company accounts for its investment in Well Lift Inc. ("WLI") using the cost method under which any return of capital reduces cost and any dividends paid are recorded as income. This investment is considered a level 3 fair value measurement and its value will be evaluated for impairment periodically and when management identifies any events or changes in circumstances that might have a significant adverse effect on the fair value of the investment.

Note 8 – Restructuring

Separation of GARP® Artificial Lift Technology Operations

During the quarter ended December 31, 2015, we conducted a strategic review of our GARP® artificial lift technology operations and consummated a plan to separate and transfer these operations to a new entity controlled by the inventor of the technology, our former Senior Vice President of Operations, and certain former employees of the Company. We invested $108,750 in common and preferred stock of the new entity, WLI. We own 17.5% of WLI and our former employees that previously had primary responsibility for our GARP® operations own the balance of the common stock. Our preferred stock is convertible at our option into common stock which would result in our ownership of 42.5% of WLI, based on the current capital structure of WLI. The company has no contractual exposure to losses of WLI, nor does it have any obligation or agreement to provide additional funding or support to WLI if it is needed. In connection with this transaction, three employees of the Company were terminated. We accrued a restructuring charge based on agreements with the employees covering salary and benefit continuation and an acceleration of vesting of equity awards in exchange for release from liabilities and other provisions including agreements not to compete. At December 31, 2015, we recorded a personnel restructuring charge of $688,205 consisting of $59,339 in stock-based compensation and $628,866 of accrued separation and benefits expense. Our current estimate of remaining restructuring obligations as of June 30, 2016 is as follows:

Type of Cost	December 31, 2015	Payments	Adjustments to Cost	June 30, 2016
Salary expense	$ 530,387	$(176,796)	$ —	$353,591
Payroll taxes and benefits expense	98,479	(32,582)	—	65,897
Accrued liability for restructuring costs	$ 628,866	$(209,378)	$ —	$419,488

Other Restructuring Impairments

Also in connection with the December 2015 separation of GARP®, we and WLI entered into an agreement under which we transferred our technology assets, including our patents and trademarks, to WLI in exchange for a perpetual royalty of 5% on all future gross revenues associated with the GARP® technology. We reduced the carrying value of these exchanged technology assets to our estimate of their expected discounted net present value, which was $108,512. This estimate was based on the recent financial results from our artificial lift technology operations and the current depressed state of the oil and gas industry and the potential upside cases were assigned relatively low probabilities for accounting purposes. This resulted in an impairment charge of $469,395. In addition, we transferred certain inventory and minor fixed assets to WLI which had no further use in our operations and were deemed to have negligible market or salvage value. This resulted in impairments of $92,901 to equipment inventory and $6,932 to fixed assets, respectively. These impairments total $569,228 and are included in restructuring charges.

Restructuring of Oil and Gas Operations

On November 1, 2013, we undertook an initiative to refocus our business that resulted in an adjustment of our workforce with less emphasis on engineering and greater emphasis on sales and marketing. In exchange for severance and non-compete agreements with the terminated employees, we recorded a restructuring charge of $1,332,186 representing $376,365 of stock-based compensation from the accelerated vesting of equity awards and $955,821 of estimated severance compensation and benefits to be paid during the twelve months ended December 31, 2014. All of the Company's obligations under these agreements had been fulfilled at December 31, 2014, extinguishing the liability. Our disposition of the accrued restructuring charges is reflected in the following schedule:

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Type of Cost	Balance at December 31, 2013	Payments	Adjustment to Cost	June 30, 2015
Salary expense	$ 615,721	$(615,721)	$—	$ —
Incentive compensation costs	185,525	(185,525)	—	—
Payroll taxes and benefits expense	154,575	(110,144)	(44,431)	—
Accrued liability for restructuring costs	$ 955,821	$(911,390)	$(44,431)	$ —

Note 9 – Accrued Liabilities and Other

As of June 30, 2016 and June 30, 2015 our other current liabilities consisted of the following:

	June 30, 2016	June 30, 2015
Accrued incentive and other compensation	$999,172	$578,910
Accrued restructuring charges	419,488	—
Asset retirement obligations due within one year	201,896	57,223
Accrued royalties, including suspended accounts	49,580	75,164
Accrued franchise taxes	62,834	94,885
Payable for settled derivatives	318,708	—
Accrued - other	46,273	49,191
Accrued liabilities and other	$2,097,951	$855,373

Note 10 –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, 2016 and 2015:

	Years Ended 2016	2015
Asset retirement obligations—beginning of period	$772,990	$352,215
Liabilities incurred (a)	28,505	564,019
Liabilities settled	—	(137,604)
Liabilities sold	—	(52,526)
Accretion of discount	49,054	34,866
Revisions to previous estimates	111,647	12,020
Asset retirement obligations — end of period	962,196	772,990
Less: current asset retirement obligations	(201,896)	(57,223)
Long-term portion of asset retirement obligations	$760,300	$715,767

(a) Liabilities incurred during fiscal 2015 relate to our share of the estimated abandonment costs of the wells and facilities in the Delhi field subsequent to the reversion of our working interest.

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Note 11 – Stockholders' Equity
Common Stock
Commencing in December 2013, the Board of Directors initiated a quarterly cash dividend on our common stock at a quarterly rate of $0.10 per share and subsequently adjusted this rate to $0.05 per share during the quarter ended March 31, 2015. We paid cash dividends of $6,565,823, $9,833,642 and $9,723,833 from retained earnings to our common shareholders during the years ended June 30, 2016, 2015 and 2014, respectively.
On May 12, 2015, the Board of Directors approved a share repurchase program covering up to $5 million of the Company's common stock. Since commencement in June 2015, we have repurchased 265,762 shares at an average price of $6.05 per share, for total cost of $1,609,008. This includes 202,390 shares purchased during the year ended June 30, 2016, at an average price of $5.80, for total cost of $1,173,899. Under the program's terms, shares are repurchased only on the open market and in accordance with the requirements of the Securities and Exchange Commission. Such shares are initially recorded as treasury stock, then subsequently canceled. The timing and amount of repurchases depends upon several factors, including financial resources and market and business conditions. There is no fixed termination date for this repurchase program, and it may be suspended or discontinued at any time. We have not repurchased any shares since December 2015.
During the year ended June 30, 2014, we issued (i) 1,568,832 shares of our common stock upon the exercise of incentive stock options (ISOs), receiving cash proceeds totaling $3,252,801, and (ii) 2,635,696 of our common shares upon cashless exercises of nonqualified stock options ("NQSOs") and incentive warrants, all being exercised on a net basis, except for 50,956 of previously acquired shares owned by option holders that were swapped in payment of the exercise price. The weighted average cost of these swapped shares was $12.14.
In fiscal 2014, we retired 801,889 shares of treasury stock acquired in previous fiscal years at a cost of $1,019,840 and 186,714 treasury shares acquired during fiscal 2014 from employees and directors at an average cost of $12.18 per share or $2,273,857. The shares acquired in 2014 were received in satisfaction of payroll tax liabilities from the exercise of stock options and vesting of restricted stock (requiring cash outlays by us) and 50,956 shares were received from option holders in cashless stock option exercises, using stock previously owned by the option holder.
Series A Cumulative Perpetual Preferred Stock
At June 30, 2016, there were 317,319 shares of the Company’s 8.5% Series A Cumulative (perpetual) Preferred Stock outstanding. The Series A Cumulative Preferred Stock cannot be converted into our common stock and there are no sinking fund or redemption rights available to the holders thereof. Effective July 1, 2014, we can redeem this preferred stock at any time for the stated liquidation value of $25.00 per share plus accrued dividends. With respect to dividend rights and rights upon our liquidation, winding-up or dissolution, the Series A Preferred Stock ranks senior to our common stockholders, 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 through its Dividend Committee. We paid dividends of $674,302 to holders of our Series A Preferred Stock during each of the years ended June 30, 2016, 2015, and 2014.

Tax Treatment of Dividends to Recipients

Based on our current projections for the fiscal year ending June 30, 2016, we expect all preferred and common dividends for this fiscal year will be treated for tax purposes as qualified dividend income to the recipients. For the fiscal year ended June 30, 2015, 100% of cash dividends on preferred stock were treated as qualified dividend income. For the same period, approximately 86% of cash dividends on common shares were treated as a return of capital to stockholders and the remainder of 14% were treated as qualified dividend income. For fiscal year ended June 30, 2014, all cash dividends on preferred and common stock were treated for tax purposes as a return of capital to our shareholders.

Note 12—Stock-Based Incentive Plan

Under the terms of the Evolution Petroleum Corporation Amended and Restated 2004 Stock Plan (the "Plan"), we have granted option awards to purchase common stock (the "Stock Options"), restricted common stock awards ("Restricted Stock"), contingent restricted common stock awards ("Contingent Restricted Stock") and/or unrestricted fully vested common stock, to employees, directors, and consultants of the Company. The Plan authorizes the issuance of 6,500,000 shares of common stock prior to its expiration on October 24, 2017 and 282,133 shares remain available for grant as of June 30, 2016.

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Stock Options and Incentive Warrants

No Stock Options have been granted since August 2008 and all compensation costs attributable to Stock Options have been recognized in prior periods. No Incentive Warrants have been granted since February 2006. All compensation costs attributable to these awards have been recognized in prior periods and all remaining awards were exercised in November 2013. The following summary presents information regarding outstanding Stock Options as of June 30, 2016, and the changes during the period:

	Number of Stock Options	Weighted Average Exercise Price	Aggregate Intrinsic Value(1)	Weighted Average Remaining Contractual Term (in years)
Stock Options outstanding at July 1, 2015	91,061	$ 2.50		
Exercised	(50,000)	2.55		
Expired	(5,830)	4.02		
Stock Options outstanding at June 30, 2016	35,231	$ 2.19	$ 115,558	1.2
Vested at June 30, 2016	35,231	$ 2.19	$ 115,558	1.2
Exercisable at June 30, 2016	35,231	$ 2.19	$ 115,558	1.2

(1) Based upon the difference between the market price of our common stock on the last trading date of the period ($5.47 as of June 30, 2016) and the Stock Option exercise price of in-the-money Stock Options.

For the year ended June 30, 2016, there were 50,000 Stock Options exercised with an aggregate intrinsic value of $131,000. For the year ended June 30, 2015, there were 87,000 Stock Options exercised, with an aggregate intrinsic value of $501,810. For the year ended June 30, 2014, there were 4,644,759 Stock Options and Incentive Warrants exercised with an aggregate intrinsic value of $47,504,114.

No stock options vested during the years ended June 30, 2016, 2015, and 2014.

Restricted Stock and Contingent Restricted Stock

Prior to August 28, 2014, all Restricted Stock grants contained a four-year vesting period based solely on service. Restricted Stock which vests based solely on service is valued at the fair market value on the date of grant and are amortized over the service period.

In August 2014 and in December 2015, the Company awarded grants of both Restricted Stock and Contingent Restricted Stock as part of its long-term incentive plan. Such grants, which expire after four years if unvested, contain service-based, performance-based and market-based vesting provisions. The common shares underlying the Restricted Stock grants were issued on the date of grant, whereas the Contingent Restricted Stock are reserved from the Plan, but will be issued only upon the attainment of specified performance-based or market-based vesting provisions.

Performance-based grants vest upon the attainment of earnings, revenue and other operational goals and require that the recipient remain an employee of the Company through the vesting date. The Company recognizes compensation expense for performance-based awards ratably over the expected vesting period based on the grant date fair value when it is deemed probable, for accounting purposes, that the performance criteria will be achieved. The expected vesting period may be deemed to be shorter than the four-year term. As of June 30, 2016, certain performance-based awards were not considered probable of vesting for accounting purposes and no compensation expense has been recognized with regard to these awards. If these awards are later determined to be probable of vesting, cumulative compensation expense would be recorded at that time and amortization would continue over the remaining expected vesting period.

Market-based awards entitle employees to vest in a fixed number of shares when the three-year trailing total return on the Company’s common stock exceeds the corresponding total returns of various quartiles of companies comprising the SIG Exploration and Production Index (NASDAQ EPX) during defined measurement periods. The fair value and expected vesting period of these awards were determined using a Monte Carlo simulation based on the historical volatility of the Company's total return compared to the historical volatilities of the other companies in the index. During the fiscal year ended June 30, 2016, we granted market-based awards with fair values ranging from $2.93 to $5.07, all with an expected vesting period of 3.83 years, based on the various quartiles of comparative market performance. During the fiscal year ended June 30, 2015, we granted market-based awards with fair values ranging from $4.26 to $8.40 and with expected vesting periods of 3.30 years to 2.55 years, based on the various quartiles of comparative market performance. Compensation expense for market-based awards is recognized over the expected vesting period using the straight-line method, so long as the award holder remains an employee of the Company. Total compensation expense is based on the fair value of the awards at the date of grant and is independent of vesting or expiration of the awards, except for termination of service.

In December 2015, one employee resigned and three others left the Company when we restructured our artificial lift technology operations. As a result 31,467 restricted shares and 14,212 contingent restricted shares were forfeited. Also in connection with the restructuring, at the Company's request in February 2016, certain employees agreed to voluntarily relinquish 31,307 restricted performance-based shares and 15,654 contingent performance-based shares in exchange for 22,016 shares of service-based restricted stock subject to vesting in three annual tranches ending on August 28, 2018.
Unvested Restricted Stock awards at June 30, 2016 consisted of the following:

Award Type	Number of Restricted Shares	Weighted Average Grant-Date Fair Value
Service-based awards	224,515	$ 7.08
Performance-based awards	89,079	7.17
Market-based awards	93,254	5.50
Unvested at June 30, 2016	406,848	$ 6.74

The following table sets forth the Restricted Stock transactions for the year ended June 30, 2016:

	Number of Restricted Shares	Weighted Average Grant-Date Fair Value	Unamortized Compensation Expense at June 30, 2016	Weighted Average Remaining Amortization Period (Years)
Unvested at July 1, 2015	262,227	$ 9.37	$ —	
Service-based awards granted	164,610	5.84		
Performance-based awards granted	64,752	6.09		
Market-based awards granted	64,752	4.58		
Vested	(86,719)	8.73		
Forfeited	(62,774)	9.72		
Unvested at June 30, 2016	406,848	$ 6.74	$ 1,536,125	2.6

During the years ended June 30, 2016, 2015, and 2014, there were 86,719, 91,306, and 277,198 shares of Restricted Stock that vested with a total grant date fair value of $757,229, $766,970, and $1,796,243, respectively.

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Unvested Contingent Restricted Stock awards at June 30, 2016 consisted of the following:

Award Type	Number of Contingent Restricted Shares	Weighted Average Grant-Date Fair Value
Performance-based awards	44,542	$ 7.17
Market-based awards	46,630	3.34
Unvested at June 30, 2016	91,172	$ 5.21

The following table summarizes Contingent Restricted Stock activity:

	Number of Restricted Stock Units	Weighted Average Grant-Date Fair Value	Unamortized Compensation Expense at June 30, 2016 (1)	Weighted Average Remaining Amortization Period (Years)
Unvested at July 1, 2015	56,286	$ 8.20		
Performance-based awards granted	32,376	6.09		
Market-based awards granted	32,376	2.93		
Forfeited	(29,866)	$ 9.33		
Unvested at June 30, 2016	91,172	$ 5.21	$ 107,219	2.8

(1) Excludes $122,268 of potential future compensation expense for performance-based awards for which vesting is not considered probable at this time for accounting purposes.

Stock-based Compensation Expense

For the years ended June 30, 2016, 2015, and 2014, we recognized stock-based compensation expense related to Restricted Stock, Contingent Restricted Stock grants, and Stock Option grants of $1,809,548, $943,653, and $1,728,687, respectively. Included in these amounts are stock-based compensation expense of $59,339 for the year ended June 30, 2016 and $376,365 for the year ended June 30, 2014 that were reflected in restructuring charges.

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Note 13 – Supplemental Disclosure of Cash Flow Information
Our supplemental disclosures of cash flow information for the years ended June 30, 2016, 2015, and 2014 are as follows:

	June 30, 2016	2015	2014
Income taxes paid	$540,000	$220,000	$755,941
Income tax refunds	1,556,999	331,733	—
Non-cash transactions:			
Increase (decrease) in accrued purchases of property and equipment	(2,250,048)	5,422,566	(183,766)
Deferred loan costs charged to oil and gas property costs	107,196	—	—
Oil and natural gas property costs attributable to the recognition of asset retirement obligations	140,151	576,039	66,976
Mengel working interest acquired in Delhi Field litigation settlement	596,500	—	—
Royalty rights acquired through non-monetary exchange of patent and trademark assets	108,512	—	—
Previously acquired Company shares swapped by holders to pay stock option exercise price	$76,500	$—	$618,606
Accrued purchases of treasury stock	(170,283)	170,283	—

Note 14 – Income Taxes
We file a consolidated federal income tax return in the United States and various combined and separate filings in several state and local jurisdictions.
There were no unrecognized tax benefits nor any accrued interest or penalties associated with unrecognized tax benefits during the years ended June 30, 2016, 2015 and 2014. 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, 2013 through June 30, 2015 for federal tax purposes and for the years ended June 30, 2011 through June 30, 2015 for state tax purposes.
The components of our income tax provision (benefit) are as follows:

	June 30, 2016	June 30, 2015	June 30, 2014
Current:			
Federal	$8,731,290	$1,413,296	$386,018
State	264,254	608,436	161,168
Total current income tax provision	8,995,544	2,021,732	547,186
Deferred:			
Federal	541,891	1,282,059	1,319,727
State	33,344	140,430	25,085
Total deferred income tax provision	575,235	1,422,489	1,344,812
	$9,570,779	$3,444,221	$1,891,998

The following table presents the reconciliation of our income taxes calculated at the statutory federal tax rate, currently 34%, to the income tax provision in our financial statements. The effective tax rate for 2016 is less than the statutory rate primarily due to the benefit derived from statutory depletion in excess of tax basis. The effective tax rates for 2015 and 2014 exceed the statutory rate as a result of state income taxes, primarily in the state of Louisiana, with smaller adjustments related to stock-based compensation and other permanent differences.

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	June 30, 2016	June 30, 2015	June 30, 2014
Income tax provision (benefit) computed at the statutory federal rate	$11,638,588	$2,868,267	$1,866,366
Reconciling items:			
Depletion in excess of basis	(2,242,620)	—	—
State income taxes, net of federal tax benefit	196,415	595,708	189,081
Permanent differences related to stock-based compensation	—	—	(155,817)
Other permanent differences	(21,604)	(19,754)	(7,632)
Income tax provision	$9,570,779	$3,444,221	$1,891,998

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 to the expected reversal date of the temporary difference or the expected utilization date for tax attribute carryforwards.

	Asset (Liability)		
	June 30, 2016	June 30, 2015	June 30, 2014
Deferred tax assets:			
Non-qualified stock-based compensation	$553,182	$173,647	$134,469
Net operating loss carry-forwards	386,808	400,288	427,249
AMT credit carry-forward*	—	701,254	701,254
Other	130,947	91,113	165,775
Gross deferred tax assets	1,070,937	1,366,302	1,428,747
Valuation allowance	(292,446)	(292,446)	(292,446)
Total deferred tax assets	778,491	1,073,856	1,136,301
Deferred tax liability:			
Oil and natural gas properties	(12,513,863)	(12,233,993)	(10,873,949)
Total deferred tax liability	(12,513,863)	(12,233,993)	(10,873,949)
Net deferred tax liability	$(11,735,372)	$(11,160,137)	$(9,737,648)

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* In fiscal 2016 we used our total AMT credit carry-forward of $901,545. Our previous deferred tax asset above did not include $200,291 of AMT credit carry-forward associated with the tax benefit related to stock-based compensation.

The above assets and liabilities are present on the balance sheet as follows:

	June 30, 2016	June 30, 2015	June 30, 2014
Current deferred tax asset	$ 105,321	$ 82,414	$ 159,624
Non-current deferred tax liability	11,840,693	11,242,551	9,897,272
Net liability	11,735,372	11,160,137	9,737,648

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As of June 30, 2016, we had a federal tax loss carryforward of approximately $1.2 million that we acquired through the reverse merger in May 2004. The majority of the tax loss carryforwards from the reverse merger expired without being utilized. We will be able to utilize a maximum of $0.3 million of these carryforwards in equal annual amounts of $39,648 through 2023 and the balance is not able to be utilized based on the provisions of IRC Section 382. We have recorded a valuation allowance for the portion of our net operating loss that is limited by IRC Section 382.

During fiscal 2016 we utilized the remaining amount of $25.3 million of net operating losses ("NOL's") created primarily from tax deductions in excess of book deductions related to the exercise of non-qualified stock options and incentive warrants in fiscal 2014. NOL's related to such stock-based awards had not affected our future tax provision for financial reporting purposes, nor had it been recognized as a deferred tax asset for these future benefits. In fiscal 2016, 2015 and 2014, we recognized a tax benefit for utilization of these NOL's to offset cash taxes that would otherwise have been payable as an increase in additional paid in capital, in amounts of $9,650,657, $1,633,946 and $509,096 respectively.

In late September 2015, we received a $1.5 million refund payment of cash taxes paid to the State of Louisiana over a three-year period ended June 30, 2014. We also received $57,467 from the State of Louisiana for interest on the refund and recorded it as a reduction of current income tax expense. This carryback of tax losses resulted from the exercise of stock options and incentive warrants in fiscal 2014 and, accordingly, we recognized this benefit as an increase in additional paid-in capital for financial reporting purposes. This carryback utilized approximately $19.1 million of an estimated $24.2 million net loss for state tax purposes. The remaining balance of this net loss carryforward in Louisiana was utilized in the tax return for the year ended June 30, 2015.

In addition, as of June 30, 2016, the Company has an estimated carryforward of percentage depletion in excess of basis of approximately $5.0 million. These future deductions are limited to 65% of taxable income in any period.

Note 15 – Related Party Transactions

On June 30, 2011, we entered into a Technology Assignment Agreement with the Company’s Senior Vice President of Operations to acquire exclusive, perpetual, non-cancelable rights to the patented artificial lift technology he developed while employed by the Company. Under the agreement, he was paid a fee when the technology was employed. For the years ended June 30, 2016, 2015 and 2014, we made payments of $0, $26,579 and $10,113, respectively, under the agreement, while he served as an officer of the Company. Our obligations with respect to this agreement were terminated in December 2015 in connection with the transfer of our artificial lift technology operations to Well Lift Inc.

Note 16 – Net Income Per Share

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

	June 30, 2016	2015	2014
Numerator			
Net income attributable to common shareholders	$23,986,060	$4,317,555	$2,923,011
Denominator			
Weighted average number of common shares – Basic	32,810,375	32,817,456	30,895,832
Effect of dilutive securities:			
Contingent restricted stock grants	9,378	4,422	—
Stock Options	41,478	102,140	1,668,235
Total weighted average dilutive securities	50,856	106,562	1,668,235
Weighted average number of common shares and dilutive potential common shares used in diluted EPS	32,861,231	32,924,018	32,564,067
Net income per common share – Basic	$0.73	$0.13	$0.09
Net income per common share – Diluted	$0.73	$0.13	$0.09

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The following were reflected in the calculation of diluted earnings per share as of June 30, 2016:

Outstanding Potential Dilutive Securities	Weighted Average Exercise Price	Outstanding at June 30, 2016
Contingent Restricted Stock grants	$ —	91,172
Stock Options	2.19	35,231
Total	$ 0.61	126,403

The following were reflected in the calculation of diluted earnings per share as of June 30, 2015:

Outstanding Potential Dilutive Securities	Weighted Average Exercise Price	Outstanding at June 30, 2015
Contingent Restricted Stock grants	$ —	56,286
Stock Options	$ 2.50	91,061
Total	$ 1.55	147,347

The following were reflected in the calculation of diluted earnings per share as of June 30, 2014:

Outstanding Potential Dilutive Securities	Weighted Average Exercise Price	Outstanding at June 30, 2014
Stock Options	$ 2.08	178,061

Note 17 – Credit Agreements

Senior Secured Credit Agreement

On April 11, 2016, the Company entered into a new three-year, senior secured reserve-based credit facility ("Facility") in an amount up to $50 million. The Facility replaces the Company's previous unsecured credit facility which was set to expire on April 29, 2016 and was terminated in early April. The initial borrowing base under the Facility was set at $10 million and the Company has no outstanding borrowings. Proceeds from the Facility may be used for the acquisition and development of oil and gas properties and for letters of credit and other general corporate purposes. Availability of borrowings under the Facility is subject to semi-annual borrowing base redeterminations.

The Facility included a placement fee of 0.50% on the initial borrowing base, amounting to $50,000, and carries a commitment fee of 0.25% per annum on the undrawn portion of the borrowing base. Any borrowings under the Facility will bear interest, at the Company’s option, at either Libor plus 2.75% or the Prime Rate, as defined, plus 1.00%. The Facility contains financial covenants including a requirement that the Company maintain, as of the last day of each fiscal quarter, (a) a maximum total leverage ratio of not more than 3.00 to 1.00, (b) a debt service coverage ratio of not less than 1.10 to 1.00, and (c) a consolidated tangible net worth of not less than $40 million, all as defined under the Facility.

In connection with this agreement, the Company incurred $168,972 of debt issuance costs. Such costs were capitalized in Other Assets and are being amortized to expense. The unamortized balance in debt issuance costs related to the Facility was $155,009 as of June 30, 2016.

Unsecured Revolving Credit Agreement

On February 29, 2012, the Company and a commercial bank entered into an unsecured credit agreement with a four year term. The agreement had provided $5 million of availability, which the Company never utilized. The original expiration date was extended to April 29, 2016. In connection with this agreement, the Company had incurred $179,468 of debt issuance costs. Such costs had been capitalized in Other Assets and have been completely amortized to expense.

Note 18 – Commitments and Contingencies

On December 13, 2013, Evolution Petroleum Corporation and its wholly-owned subsidiaries, Tertiaire Resources Company and NGS Sub. Corp. (collectively, “Evolution”) filed a lawsuit in the 133rd Judicial District Court of Harris County,

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Texas, against Denbury Onshore, LLC (“Denbury”) alleging breaches of certain 2006 agreements between the parties regarding the Delhi field in northeast Louisiana. On June 24, 2016, Evolution entered into a settlement agreement with Denbury to resolve all outstanding disputes and claims between the parties, including claims related to the pending litigation between Evolution and Denbury with respect to the Delhi field. Pursuant to the settlement, the parties dismissed with prejudice all such claims between them with respect to such litigation. In addition to clarifying certain aspects of the parties' ongoing relationship, the settlement resolves (a) claims by Evolution in connection with the June 2013 incident at the Delhi field involving a release of well fluids (the “June 2013 Incident”); (b) disputes regarding the occurrence, determination, timing, nature and terms of “payout” and Evolution's related reversionary interest in the Delhi Field; and (c) any claims by Denbury related to the purchase by Denbury of its original Delhi field interest from the Company. Under the terms of the settlement, Evolution retains any and all rights under its existing agreements with Denbury regarding indemnification for any costs which are asserted or arise subsequent to the effective date of the settlement and which relate to periods prior to reversion of its working interest, including any such costs related to the June 2013 Incident. See Note 3 — Delhi Field Litigation Settlement.

On December 3, 2013, our wholly owned subsidiary, NGS Sub Corp., was served with a lawsuit filed in the 8th Judicial District Court of Winn Parish, Louisiana by Cecil M. Brooks and Brandon Hawkins, residents of Louisiana, alleging that in 2006 a former subsidiary of NGS Sub Corp. improperly disposed of water from an off-lease well into a well located on the plaintiffs’ lands in Winn Parish. The plaintiffs requested monetary damages and other relief. NGS Sub Corp. divested its ownership of the property in question along with its ownership of the subsidiary in 2008 to a third party. The district court granted our exception of no right of action and dismissed certain claims against NGS Sub Corp. The plaintiffs subsequently filed an amended petition naming NGS Sub Corp. and the Company as defendants. NGS Sub Corp. and the Company have denied the plaintiffs’ claims. Various pretrial motions filed on behalf of multiple parties were recently decided by the court and discovery is in process. We will continue to vigorously defend all claims by plaintiffs and consider the likelihood of a material loss to the Company in this matter to be remote.

Lease Commitments. We had a non-cancelable lease for office space that expired on July 31, 2016. Late in fiscal 2016, the Company entered into a new non-cancelable office space with a three year term ending on May 31, 2019. Future minimum lease commitments as of June 30, 2016 under these operating leases are as follows:

For the fiscal year ended June 30,	
2017	$80,235
2018	73,073
2019	66,984
Total	$220,292

Rent expense for the years ended June 30, 2016, 2015, and 2014 was $182,626, $175,103, and $174,229, respectively.

Capital Expenditures. See Note 6 for discussion of capital projects in progress and expected remaining capital commitments.

Note 19 – Concentrations of Credit Risk

Major Customers. We market all of our oil and natural gas production from the properties we operate. We do not currently market our share of crude oil production from Delhi. Although we have the right to take our working interest production at Delhi in-kind, we are currently selling our oil under the Delhi operator's agreement with Plains Marketing L.P. for the delivery of our oil to a pipeline at the field. The majority of our operated gas, oil and condensate production is sold to 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, 2016, 2015, and 2014. The loss of our purchaser at the Delhi field or disruption to pipeline transportation from the field could adversely affect our net realized pricing and potentially our near-term production levels. The loss of any of our other purchasers would not be

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expected to have a material adverse effect on our operations.

	Year Ended June 30,		
Customer	2016	2015	2014
Plains Marketing L.P. (includes Delhi production)	99 %	99 %	96 %
Enterprise Crude Oil LLC	— %	— %	2 %
Flint Hills	— %	— %	1 %
ETC Texas Pipeline, LTD.	— %	— %	1 %
All others	1 %	1 %	— %
Total	100%	100%	100%

Accounts Receivable. Substantially all of our accounts receivable result from oil and natural gas sales to third parties in the oil and natural gas industry. Our concentration of customers in this industry may impact our overall credit risk.

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 20 – Retirement Plan

We have a Company sponsored 401(k) Retirement Plan ("Plan") which covers all full-time employees. We currently match 100% of employees' contributions to the Plan, to a maximum of the first 6% of each participant's eligible compensation, with Company contributions fully vested when made. Our matching contributions to the Plan totaled $88,348, $85,676, and $116,873 for the years ended June 30, 2016, 2015, and 2014, respectively.

Note 21 – Derivatives

In early June 2015, the Company began using derivative instruments to reduce its exposure to crude oil price volatility for a substantial portion of its near-term forecasted production. The Company's objectives for this program were to achieve a more predictable level of cash flows to support the Company’s capital expenditure program and to provide better financial visibility for the payment of dividends on common stock. The Company uses both fixed price swap agreements and costless collars to manage its exposure to crude oil price risk. While these derivative instruments are intended to limit the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. The Company does not intend to enter into derivative instruments for speculative or trading purposes.

The Company accounts for derivatives under the provisions of ASC 815 Derivatives and Hedging ("ASC 815") under which the Company records the fair value of the instruments on the balance sheet at each reporting date, with changes in fair value recognized in income. Given cost and complexity considerations, the Company did not elect to use cash flow hedge accounting provided under ASC 815. Under cash flow hedge accounting, the effective portion of the change in fair value of the derivative instruments would be deferred in other comprehensive income and not recognized in earnings until the underlying hedged item impacts earnings.

These derivative instruments can result in both fair value asset and liability positions held with each counterparty. These positions are offset to a single net fair value asset or liability at the end of each reporting period. The Company nets its fair value amounts of derivative instruments executed with the same counterparty pursuant to ISDA master agreements, which provide for net settlement over the term of the contract and in the event of default or termination of the contract. The fair value derivative instruments where the Company is in a net asset position with its counterparty as of June 30, 2016 totaled $14,132. Refer to Note 22–Fair Value Measurement for derivative asset and derivative liability balances before offsetting.

The Company monitors the credit rating of its counterparties and believes it does not have significant credit risk. Accordingly, we do not currently require our counterparties to post collateral to support the net asset positions of our

derivative instruments. As such, the Company is exposed to credit risk to the extent of nonperformance by the counterparties to its derivative instruments.
For the year ended June 30, 2016, the Company recorded in the consolidated statement of operations a gain on derivative

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instruments of $3,439,229 consisting of a realized gain of $3,315,123 on settled derivatives and an unrealized gain of $124,106 on unsettled derivatives. For the year ended June 30, 2015, the Company recorded in the consolidated statement of operations a net unrealized loss on unsettled derivatives of $109,974.

The following sets forth a summary of the Company’s crude oil derivative positions at average NYMEX WTI prices as of June 30, 2016.

Period	Type of Contract	Volumes (in Bbls./day)	Weighted Average Floor Price per Bbl.	Weighted Average Ceiling Price per Bbl.	Weighted Average Collar Spread per Bbl.
Months of July 2016 through September 2016	Costless Collar	600	$45.00	$55.00	$10.00

Subsequent to June 30, 2016, the Company's July and August collars expired without settlement as the respective NYMEX prices for those months fell between the floor and ceiling prices.

Note 22 – Fair Value Measurement

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

The three levels are defined as follows:

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

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

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

Fair Value of Derivative Instruments. The following table summarize the location and amounts of the Company’s assets and liabilities measured at fair value on a recurring basis as presented in the consolidated balance sheets as of June 30, 2016. All items included in the tables below are Level 2 inputs within the fair value hierarchy:

	June 30, 2016		
Asset (Liability)	Gross Amounts Recognized	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts Presented in the Consolidated Balance Sheets
Current derivative assets	$45,263	$ (31,131)	$ 14,132
Current derivative liabilities	(31,131)	31,131	—
Total	$14,132	$ —	$ 14,132

The fair values of the Company’s derivative assets and liabilities are based on a third-party industry-standard pricing model that uses market data obtained from third-party sources, including quoted forward prices for oil and gas, discount rates and volatility factors. The fair values are also compared to the values provided by the counterparty for reasonableness and are adjusted for the counterparties credit quality for derivative assets and the Company’s credit quality for derivative liabilities. To date, adjustments for credit quality have not had a material impact on the fair values.

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Note 23 – Supplemental Disclosures about Oil and Natural Gas Producing Properties (unaudited)
Costs incurred for oil and natural gas property acquisition, exploration and development activities
The following table summarizes costs incurred and capitalized in oil and natural gas property acquisition, exploration and development activities. Property acquisition costs are those costs incurred to lease property, including both undeveloped leasehold and the purchase of reserves in place. Exploration costs include costs of identifying areas that may warrant examination and examining specific areas that are considered to have prospects containing oil and natural gas reserves, including costs of drilling exploratory wells, geological and geophysical costs and carrying costs on undeveloped properties. Development costs are incurred to obtain access to proved reserves, including the cost of drilling. Exploration and development costs also include amounts incurred due to the recognition of asset retirement obligations of $140,151, $576,039 and $66,976 during the years ended June 30, 2016, 2015, and 2014, respectively.

	For the Years Ended June 30,		
	2016	2015	2014
Oil and Natural Gas Activities			
Property acquisition costs:			
Proved property	$—	$—	$—
Unproved property (a)	596,500	—	47,344
Exploration costs	—	—	757,423
Development costs	19,093,200	10,975,637	18,566
Total costs incurred for oil and natural gas activities	$19,689,700	$10,975,637	$823,333

(a) As described in Note 3 — Delhi Field Litigation Settlement, we received a 23.9% working interest in the non-producing Mengel Interval with an estimated fair value of $596,500. This cost is included in properties subject to amortization.

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, 2016, 2015, and 2014, which requires the application of the previous 12 months unweighted arithmetic average first-day-of-the-month price, and current costs held constant throughout the projected reserve life, when estimating whether reserve quantities are economical to produce.
Proved oil and natural gas reserves are estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and natural gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. There are uncertainties inherent in estimating quantities of proved oil and natural gas reserves, projecting future production rates, and timing of development expenditures. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered.

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

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

	Crude Oil (Bbls)	Natural Gas Liquids (Bbls)	Natural Gas (Mcf)	BOE
Proved developed and undeveloped reserves:				
June 30, 2013	12,782,755	979,885	22,797	13,766,440
Revisions of previous estimates (a)	(1,919,052)	1,269,588	2,412,677	(247,350)
Improved recovery, extensions and discoveries	17,146	32,731	498,044	132,884
Sales of minerals in place	(184,722)	—	—	(184,722)
Production (sales volumes)	(169,783)	(3,516)	(26,655)	(177,742)
June 30, 2014	10,526,344	2,278,688	2,906,863	13,289,510
Revisions of previous estimates (b)	(64,074)	156,195	(2,894,703)	(390,330)
Improved recovery, extensions and discoveries	—	—	—	—
Sales of minerals in place	—	—	—	—
Production (sales volumes)	(450,294)	(1,288)	(7,221)	(452,786)
June 30, 2015	10,011,976	2,433,595	4,939	12,446,394
Revisions of previous estimates (c)	(765,385)	(198,233)	(3,319)	(964,171)
Improved recovery, extensions and discoveries	—	—	—	—
Sales of minerals in place	—	—	—	—
Production (sales volumes)	(658,041)	(491)	(1,620)	(658,802)
June 30, 2016	8,588,550	2,234,871	—	10,823,421
Proved developed reserves:				
June 30, 2013	10,077,522	8,539	22,797	10,089,861
June 30, 2014	7,858,224	32,164	481,042	7,970,562
June 30, 2015	7,347,231	1,572	4,939	7,349,626
June 30, 2016	7,168,249	—	—	7,168,249
Proved undeveloped reserves:				
June 30, 2013	2,705,233	971,346	—	3,676,579
June 30, 2014	2,668,120	2,246,524	2,425,821	5,318,948
June 30, 2015	2,664,745	2,432,023	—	5,096,768
June 30, 2016	1,420,301	2,234,871	—	3,655,172

(a) Significant reserve revisions occurred in the Delhi field during fiscal 2014. As a result of a fluid release event in the field, 1,817,224 BBLs of oil reserves were reclassified from proved to probable category based on the operator's decision to defer CO_2 injections in certain parts of the field. There was a positive revision of 1,679,481 BOE, which was comprised of 1,275,178 BBLs of natural gas liquids and 2,425,821 MCF of natural gas as a result of an improved design for the NGL plant in the Delhi field. The plant was expected to significantly increase recoveries of these products, particularly natural gas, which were not previously planned to be extracted from the injection volumes.

(b) The 2,894,703 negative fiscal 2015 revision for natural gas primarily reflects a 2,246,524 MCF negative revision for the Delhi field NGL plant together with a 452,786 MCF negative revision at the Giddings Field for a well that was lost due to mechanical issues. The NGL plant revision resulted from a decision during the current fiscal year to use the methane production internally to reduce field operating costs rather than selling it into the market. The 156,195 BBL positive natural gas liquids revision primarily reflects 185,499 BBL positive revision for better recovery from the redesigned NGL plant, partly offset by a 29,304 BBL negative revision due to the lost Giddings well.

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

(c) The negative revision results primarily from the removal of proved undeveloped reserves in the far eastern part of the Delhi field, referred to as Test Site 6, which were deemed uneconomic under the lower SEC price case utilized at the end of the period.

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, Extractive Activities - Oil and Gas ("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, 2016, 2015, and 2014 are as follows:

	For the Years Ended June 30,		
	2016	2015	2014
Future cash inflows	$383,491,193	$807,030,282	$1,193,515,075
Future production costs and severance taxes	(179,182,565)	(309,225,333)	(475,387,931)
Future development costs	(16,595,047)	(49,691,006)	(46,154,178)
Future income tax expenses	(45,713,438)	(123,888,665)	(195,581,510)
Future net cash flows	142,000,143	324,225,278	476,391,456
10% annual discount for estimated timing of cash flows	(64,042,824)	(165,028,739)	(250,313,784)
Standardized measure of discounted future net cash flows	$77,957,319	$159,196,539	$226,077,672

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

	Year Ended June 30,					
	2016		2015		2014	
	Oil (Bbl)	Gas (MMBtu)	Oil (Bbl)	Gas (MMBtu)	Oil (Bbl)	Gas (MMBtu)
NYMEX prices used in determining future cash flows	$42.91	n/a	$71.88	$ 3.44	$100.37	$ 4.10

There were no natural gas reserves in 2016. The NGL prices utilized for future cash inflows were based on historical prices received, where available. For the Delhi NGL plant, we utilized historical prices for the expected mix and net pricing of natural gas liquid products projected to be produced by the plant.

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:

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

	For the Years Ended June 30,		
	2016	2015	2014
Balance, beginning of year	$159,196,539	$226,077,672	$307,220,699
Net changes in sales prices and production costs related to future production	(120,832,747)	(88,043,095)	(73,439,526)
Changes in estimated future development costs	74,991	(9,585,405)	9,848,614
Sales of oil and gas produced during the period, net of production costs	(17,079,363)	(18,538,016)	(16,479,934)
Net change due to extensions, discoveries, and improved recovery	—	—	775,574
Net change due to revisions in quantity estimates	(18,821,014)	(9,391,321)	(23,757,788)
Net change due to sales of minerals in place	—	—	(3,150,277)
Development costs incurred during the period	16,327,883	7,785,095	—
Accretion of discount	21,870,650	31,974,540	45,896,187
Net change in discounted income taxes	36,598,239	34,157,767	58,073,450
Net changes in timing of production and other (a)	622,141	(15,240,698)	(78,909,327)
Balance, end of year	$77,957,319	$159,196,539	$226,077,672

(a) Due to the June 2013 fluid release event in the Delhi field, the operator expressed plans to produce the Delhi field at lower production rates. The decision to produce these reserves at lower rates over a longer period of time did not materially change the total quantities expected to be recovered, but resulted in a significant reduction in the discounted value of these reserves as of June 30, 2014.

Note 24 – Selected Quarterly Financial Data (Unaudited)

The following table presents summarized quarterly financial information for the years ended June 30, 2016 and 2015:

2016	First	Second (1)	Third	Fourth (2)
Revenues	$7,379,406	$6,622,927	$5,106,735	$7,240,434
Operating income (loss)	1,846,498	(454,987)	(681,147)	954,823
Net income (loss) available to common shareholders	$2,923,652	$654,697	$(298,183)	$20,705,894
Basic net income (loss) per share	$0.09	$0.02	$(0.01)	$0.63
Diluted net income (loss) per share	$0.09	$0.02	$(0.01)	$0.63

2015	First	Second (3)	Third	Fourth
Revenues	$4,004,827	$7,708,067	$7,064,689	$9,063,682
Operating income	1,840,866	2,162,294	1,245,990	3,334,547
Net income available to common shareholders	$960,435	$1,071,342	$566,011	$1,719,767
Basic net income per share	$0.03	$0.03	$0.02	$0.05
Diluted net income per share	$0.03	$0.03	$0.02	$0.05

(1) Includes $1.3 million restructuring charge.
(2) Includes gain on settlement of Delhi field litigation of $28.1 million.
(3) Impacted by the November 1, 2014 reversion of the Company's 23.9% working interest and 19.0% net revenue interest in the Delhi field.

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

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

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

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

Management's Report on Internal Control Over Financial Reporting

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

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Under the supervision and with the participation of management, including the Chief Executive Officer and the Chief Financial Officer, an evaluation was conducted on the effectiveness of the Company's internal control over financial reporting based on criteria established in the Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013. Management concluded that the Company maintained effective internal control over financial reporting as of June 30, 2016.

The effectiveness of our internal control over financial reporting at June 30, 2016 has been audited by Hein & Associates LLP, the independent registered public accounting firm that also audited our financial statements. Their report is included in Item 8. "Financial Statements" of this Annual Report on form 10-K under the heading Report of Independent Registered Public Accounting Firm on internal control over financial reporting.

Changes in Internal Control Over Financial Reporting

There has been no change in the Company's internal control over financial reporting during the fourth quarter ended June 30, 2016 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 2016 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 2016 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 2016 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 2016 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 2016 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.

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

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

(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.

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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.

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/ RANDALL D. KEYS
Randall D. Keys
President and Chief Executive Officer
(Principal Executive Officer)

Date: September 9, 2016

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 9, 2016	/s/ ROBERT S. HERLIN Robert S. Herlin	Executive Chairman of the Board
September 9, 2016	/s/ RANDALL D. KEYS Randall D. Keys	President and Chief Executive Officer (Principal Executive Officer)
September 9, 2016	/s/ DAVID JOE David Joe	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
September 9, 2016	/s/ RODERICK SCHULTZ Roderick Schultz	Chief Accounting Officer (Principal Accounting Officer)
September 9, 2016	/s/ EDWARD J. DIPAOLO Edward J. DiPaolo	Lead Director
September 9, 2016	/s/ GENE STOEVER Gene Stoever	Director
September 9, 2016	/s/ WILLIAM DOZIER William Dozier	Director
September 9, 2016	/s/ KELLY W. LOYD Kelly W. Loyd	Director

INDEX OF EXHIBITS

MASTER EXHIBIT INDEX

EXHIBIT NUMBER	DESCRIPTION
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	Specimen form of the Company's Common Stock Certificate (Previously filed as an exhibit to Form S-3 on June 19, 2013)
4.2	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)
4.3	2004 Stock Plan (Previously filed as an exhibit to the Company's Definitive Information Statement on Schedule 14C on August 9, 2004)
4.4	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)
4.5	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)
4.6	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)
4.7	Form of Restricted Stock Agreement (Previously filed as an exhibit to Form 8-K on May 15, 2009)
4.8	Form of Contingent Performance Stock Grant under the Evolution Petroleum Corporation Amended and Restated 2004 Stock Plan (Previously filed as an exhibit to the Company's Quarterly Report on Form 10-Q on November 7, 2014)
4.9	Majority Voting Policy for Directors (Previously filed as an exhibit to the Company's Current Report on Form 8-K on October 31, 2012)
10.1	Executive Employment Agreement of Robert S. Herlin, dated April 4, 2005 (Previously filed as an exhibit to Form 8-K on April 8, 2005)
10.2	Executive Employment Agreement of Daryl V. Mazzanti, dated June 23, 2005 (Previously filed as an exhibit to Form 8-K on June 29, 2005)
10.3	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)
10.4	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)
10.5	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)
10.6	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)
10.7	Settlement Agreement, dated June 24, 2016, by and among Denbury Onshore, LLC, Denbury Resources Inc., NGS Sub Corp., Tertiaire Resources Company, and the Company (Filed herein)
10.8	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)

10.9	Technology Assignment Agreement dated June 30, 2011 between Evolution Petroleum Corporation and Daryl Mazzanti (Previously filed as an exhibit to Form 10-K on September 11, 2015)
10.10	Credit Agreement dated April 11, 2016 between Evolution Petroleum Corporation and MidFirst Bank (Previously filed as an exhibit to Form 8-K on April 15, 2016)

EXHIBIT NUMBER	DESCRIPTION
14.1	Code of Business Conduct and Ethics for Natural Gas Systems, Inc. (Previously filed as an exhibit to Form 8-K on May 4, 2006)
21.1	List of Subsidiaries of Evolution Petroleum Corporation (Filed herein)
23.1	Consent of Hein & Associates, LLP (Filed herein)
23.2	Consent of DeGolyer and MacNaughton (Filed herein)
23.3	Consent of W.D. Von Gonten & Co. (Filed herein)
31.1	Certification of Chief Executive Officer Pursuant to Rule 15D-14 of the Securities Exchange Act of 1934, as Amended as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (Filed herein)
31.2	Certification of President and Chief Financial Officer 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 Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Filed herein)
32.2	Certification of President and Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Filed herein)
99.1	Audit Committee Charter of the Board of Directors of Natural Gas Systems, Inc. (Previously filed as an exhibit to Form 8-K on May 4, 2006)
99.2	Compensation Committee Charter of the Board of Directors of Natural Gas Systems, Inc. (Previously filed as an exhibit to Form 8-K on May 4, 2006)
99.3	Nominating Committee Charter of the Board of Directors of Natural Gas Systems, Inc. (Previously filed as an exhibit to Form 8-K on May 4, 2006)
99.4	The summary of DeGolyer and MacNaughton's Report as of June 30, 2016, on oil and gas reserves (SEC Case) dated August 26, 2016 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