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:

	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%

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

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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.

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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