EVOLUTION PETROLEUM CORP
Form 10-K
September 25, 2009
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended June 30, 2009

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

For the transition period from to

Commission File Number 001-32942

EVOLUTION PETROLEUM CORPORATION

(Exact name of registrant as specified in its charter)

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

2500 CityWest Blvd., Suite 1300, Houston, Texas 77042

(Address of principal executive offices and zip code)

(713) 935-0122

(Registrant s telephone number, including area code)

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

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: ¨ No: x

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: x 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: o No: o

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

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 o
Non-accelerated filer o	Smaller reporting company x

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates on December 31, 2008, the last business day of the registrant s most recently completed second fiscal quarter, based on the closing price on that date of $1.20 on the NYSE Amex was $15,748,620.

The number of shares outstanding of the registrant s common stock, par value $0.001, as of September 23, 2009, was 26,993,138.

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EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

2009 ANNUAL REPORT ON FORM 10-K

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This Form 10-K and the information referenced herein contain forward-looking statements within the meaning of the Private Securities Litigations Reform Act of 1995, Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. The words plan, expect, project, estimate, assume, believe, anticipate, intend, budget, forecast, predict and other similar expressions are intended to identify forward-looking statements. These statements appear in a number of places and include statements regarding our plans, beliefs or current expectations, including the plans, beliefs and expectations of our officers and directors. When considering any forward-looking statement, you should keep in mind the risk factors that could cause our actual results to differ materially from those contained in any forward-looking statement. Important factors that could cause actual results to differ materially from those in the forward-looking statements herein include the timing and extent of changes in commodity prices for oil and natural gas, operating risks and other risk factors as described in our 2008 Annual Report on Form 10-K for the year ended June 30, 2008 as filed with the Securities and Exchange Commission. Furthermore, the assumptions that support our forward-looking statements are based upon information that is currently available and is subject to change. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages. All forward-looking statements attributable to Evolution Petroleum Corporation are expressly qualified in their entirety by this cautionary statement.

We use the terms, EPM, Company, we, us and our to refer to Evolution Petroleum Corporation.

GLOSSARY OF SELECTED PETROLEUM TERMS

The following abbreviations and definitions are terms commonly used in the crude oil and natural gas industry and throughout this prospectus:

BBL. A standard measure of volume for crude oil and liquid petroleum products; one barrel equals 42 U.S. gallons.

BCF. Billion Cubic Feet of natural gas at standard temperature and pressure.

BOE. Barrels of oil equivalent. BOE is calculated by converting 6 MCF of natural gas to 1 BBL of oil.

BTU or British Thermal Unit. The standard unit of measure of energy equal to the amount of heat required to raise the temperature of one pound of water 1 degree Fahrenheit. One Bbl of crude is typically 5.8 MMBTU, and one standard MCF is typically 1 MMBTU.

CO_2. Carbon dioxide, a gas that can be found in naturally occurring reservoirs, typically associated with ancient volcanoes, and also is a major byproduct from manufacturing and power production, also utilized in enhanced oil recovery through injection into an oil reservoir.

EOR. Enhanced Oil Recovery projects involve injection of heat, miscible or immiscible gas, or chemicals into oil reservoirs, typically following full primary and secondary waterflood recovery efforts, in order to gain incremental recovery of oil from the reservoir.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geologic structural feature and/or stratigraphic feature.

Farmout. Sale or transfer of all or part of the operating rights from the working interest owner (the assignor or farmout party), to an assignee (the farmin party) who assumes all or some of the burden of development, in return for an interest in the property. The assignor may retain an overriding royalty or any other type of interest. For Federal tax purposes, a farmout may be structured as a sale or lease, depending on the specific rights and carved out interests retained by the assignor.

Gross Acres or Gross Wells. The total acres or number of wells participated in, regardless of the amount of working interest owned.

Horizontal Drilling Involves drilling horizontally out from an existing vertical well bore, thereby potentially increasing the area and reach of the well bore that is in contact with the reservoir.

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Hydraulic Fracturing Involves pumping a fluid with or without particulates into a formation at high pressure, thereby creating fractures in the rock and leaving the particulates in the fractures to ensure that the fractures remain open, thereby potentially increasing the ability of the reservoir to produce oil or gas.

LOE. Means lease operating expense(s), a current period expense incurred to operate a well.

MBOE. One thousand barrels of oil equivalent.

MCF. One thousand cubic feet of natural gas at standard conditions, being approximately sea level pressure and 60 degrees Fahrenheit temperature. Standard pressure in the state of Louisiana is deemed to be 15.025 psi by regulation, but varies in other states.

MMBTU. One million British thermal units.

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

Net Acres or Net Wells. The sum of the fractional working interests owned in gross acres or gross wells.

NGL. Natural gas liquids, being the combination of ethane, propane, butane and natural gasolines that can be removed from natural gas through processing, typically through refrigeration plants that utilize low temperatures, or through J-T plants that utilize compression, temperature reduction and expansion to a lower pressure.

NYMEX. New York Mercantile Exchange.

Operator. An oil and gas joint venture participant that manages the joint venture, pays venture costs and bills the venture s non-operators for their share of venture costs. The operator is also responsible to market all oil and gas production, except for those non-operators who take their production in-kind.

Overriding Royalty. A royalty interest that is created out of the operating or working interest. Unlike a royalty interest, an overriding royalty interest terminates with the operating interest from which it was created or carved out of. See royalty interest .

Permeability. The measure of ease with which a fluid can move through a reservoir.

Porosity. (of sand or sandstone). The relative volume of the pore space (or open area) compared to the total bulk volume of the reservoir.

Proved Developed Reserves. Proved Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as proved developed reserves only after testing by pilot project or after the operation of an installed program has confirmed through production responses that increased recovery will be achieved.

Proved Developed Nonproducing Reserves (PDNP). Proved Reserves that have been developed and no material amount of capital expenditures are required to bring on production, but production has not yet been initiated due to timing, markets, or lack of third party completed connection to a gas sales pipeline.

Proved Developed Producing Reserves (PDP). Proved Reserves that have been developed and production has been initiated.

Proved Reserves. Estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

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Proved Undeveloped Reserves (PUD). Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled.

Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Proved undeveloped reserves may not include estimates attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

PSI, or pounds per square inch, a measure of pressure. Pressure is typically measured as psig , or the pressure in excess of standard atmospheric pressure.

Present Value. When used with respect to oil and gas reserves, present value means the estimated future net revenues computed by applying current prices of oil and gas reserves (with consideration of price changes only to the extent provided by contractual arrangements) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet presented, less estimated future expenditures (based on current costs to be incurred in developing and producing the proved reserves) computed using a discount factor and assuming continuation of existing economic conditions.

Productive Well. A well that is producing oil or gas or that is capable of production.

PV-10. Means the present value, discounted at 10% per annum, of future net revenues (estimated future gross revenues less estimated future costs of production, development, and asset retirement costs) associated with proved reserves and is not necessarily the same as market value. PV-10 does not include estimated future income taxes.

Royalty or Royalty Interest. The mineral owner s share of oil or gas production (typically between 1/8 and 1/4), free of costs, but subject to severance taxes unless the lessor is a government. In certain circumstances, the royalty owner bears a proportionate share of the costs of making the natural gas saleable, such as processing, compression and gathering. A royalty interest that is coterminous with an operating or working interest is an overriding royalty interest.

Shut-in Well. A well that is not on production, but has not yet been plugged and abandoned. Wells may be shut-in in anticipation of future utility as a producing well, plugging and abandonment or other use.

Standardized Measure. The standardized measure is an estimate of future net cash flows associated with proved reserves, discounted at 10% per annum. Future net cash flows is calculated by reducing future net revenues by estimated future income tax expenses and discounting at 10% per annum. The standardized measure and PV-10 are calculated in the same exact fashion, except that the standardized measure includes future estimated income taxes discounted at 10% per annum. The determination of discounted future net cash flows under the standardized measure is in accordance with the regulations of the SEC and the Financial Accounting Standards Board.

Working Interest. The interest in the oil and gas in place which is burdened with the cost of development and operation of the property. Also called the operating interest.

Workover. A remedial operation on a completed well to restore, maintain or improve the well s production.

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Item 1. Business

General

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

Our petroleum operations began in September of 2003. We acquire established crude oil and natural gas resources and exploit them through the application of conventional and specialized technology, with the objective of increasing production, ultimate recoveries, or both.

Our team is broadly experienced in oil and gas operations, development, acquisitions and financing. We follow a strategy of outsourcing most of our property accounting, human resources, administrative and non-core functions.

Our principal executive offices are located at 2500 City West Blvd, Suite 1300, Houston, Texas 77042, and our telephone number is (713) 935-0122. We maintain a website at www.evolutionpetroleum.com, but information contained on our website does not constitute part of this document.

Our stock is traded on the NYSE Amex under the ticker symbol EPM . Prior to July 17, 2006, our stock was quoted on the OTC Bulletin Board under the symbol NGSY.OB . Prior to May 26, 2004, our stock was quoted on the OTC Bulletin Board under the symbol RLYI.OB .

At June 30, 2009, we had eleven full-time employees, not including contract personnel and outsourced service providers.

Corporate History of Reverse Merger

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

On May 26, 2004, Old NGS merged into a wholly owned subsidiary of Reality. Reality was thereafter renamed Natural Gas Systems, Inc. (NGS) and adopted a June 30 fiscal year end. As part of the merger, the officers and directors of Reality resigned, the officers and directors of Old NGS became the officers and directors of NGS, and the crude oil and natural gas business of Old NGS became that of NGS. Concurrently with the listing of NGS shares on the NYSE Amex (formerly American Stock Exchange) during July 2006, NGS was renamed Evolution Petroleum Corporation to avoid confusion with similar names traded on the NYSE Amex and to better reflect our business model.

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

Business Strategy

We are a petroleum company engaged primarily in the acquisition, exploitation and development of properties for the production of crude oil and natural gas. We acquire known, underdeveloped oil and natural gas resources and exploit them through the application of capital and technology to increase production, ultimate recoveries, or both.

Our strategy is intended to generate scalable development opportunities at normally pressured depths, exhibiting relatively low completion risk, generally longer and more predictable production lives, less expenditures on infrastructure and lower operational risks.

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Within this overall strategy, we pursue three specific initiatives:

I Enhanced oil recovery (EOR), using miscible and immiscible gas flooding;

II Conventional redevelopment of bypassed primary resources within mature oil and natural gas fields utilizing modern technology and our expertise; and

III Unconventional gas resource development, using modern stimulation and completion technologies.

Our strategy is intended to generate scalable development opportunities at normally pressured depths, exhibiting relatively low completion risk, generally more predictable production lives, less expenditures on infrastructure and lower operational risks. We believe that the benefits of this approach include:

- Reduced exposure to the risk of whether resources are present;
- Reduced capital expenditures per net BOE for infrastructure, such as roads, water handling facilities and pipelines;
- Large inventory of development opportunities, which provides a more predictable future stream of drilling activity and production, as well as potentially reducing risks from short-term oil and natural gas price volatility;
- Reduced operational risks and costs associated with lower pressures and lower temperatures; and
- Control of operations, development timing and technology selection.

Our long term strategy and primary focus continue to be the increase in share value through the identification and exploitation of our petroleum resources, and converting them into proved reserves through our expertise and technology.

Near term, our focus is on (i) selective low cost development activities to optimize current production and upgrade reserve categories, (ii) emphasizing long term share value over near term earnings during the current period of low natural gas prices, and (iii) using internally generated funds and our working capital to accomplish these objectives.

Enhanced Oil Recovery (EOR) Property

Our EOR Initiative targets the use of miscible and immiscible gas flooding to achieve economic redevelopment and production of tertiary crude oil resources. Field candidates are likely to have already completed primary and secondary recovery operations, generally through water flooding.

Delhi Field

The Delhi Holt Bryant Unit in the Delhi Field in Louisiana is currently our most significant asset.

- The Delhi Holt Bryant Unit is currently being redeveloped with an EOR project utilizing CO_2 technology by a subsidiary of Denbury Resources Inc. as Operator;

- On May 5, 2009, the Operator reported that the 78 mile Delta Pipeline from Tinsley Field to the Delhi Field had been completed and tested; and

- On August 4, 2009, the Operator publicly announced that CO_2 injection is expected to commence by the fourth quarter of calendar 2009, with initial oil production response expected by mid-calendar 2010.

We believe that the Delhi Holt Bryant Unit is a strong candidate for a CO_2-EOR project due to its favorable rock characteristics, large unproven reserves remaining in place, low cost of drilling due to a relatively shallow depth and

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relatively close location to naturally occurring CO_2 reserves approximately 100 miles east of the Delhi Field. We base our belief on (i) our internal analyses of CO_2 pilot tests successfully completed in the Delhi Holt Bryant Unit by a prior field operator, (ii) our analysis of favorable analogous comparisons to successful full scale projects in the same or similar geological formation, (iii) a competitive offering process, wherein we solicited multiple major participants with CO_2-EOR expertise, funding and operating abilities, leading to confidential competitive offers made to us in writing, (iv) our qualitative assessment that the competitive offers were based on the CO_2-EOR potential of the Unit and not on the relatively minor associated proved reserves existing at that time, and (v) the buyer s willingness to commit a portion of its proved CO_2 reserves and a $100 million minimum future investment, subject to penalties for non-performance, in a CO_2 project in the Unit.

According to published reports and field records, the Delhi Field was discovered in the mid-1940 s and was extensively developed by various operators including the Sun Oil and Murphy Oil companies through the drilling and completion of approximately 450 wells, most within the first few years after discovery. According to DeGolyer & MacNaughton, the independent reservoir engineering firm engaged by us to review the project, the Delhi Field has produced approximately 192 million barrels of crude oil and substantial amounts of natural gas to date. Much of the natural gas production was processed to remove natural gas liquids and re-injected for pressure maintenance. Beginning in the late 1950 s, the field was unitized to conduct a pressure maintenance project through the injection of water into the producing reservoir in down dip injection wells (unitization is the process of combining multiple leases into a single ownership entity in order to simplify operations and equitably distribute royalties when common operations are conducted over multiple leases). Drilling operations resulted in primarily 40-acre spacing across the unit s 13,636 acres. A few wells were drilled below the targeted Tuscaloosa and Paluxy formations. The water injection pressure maintenance operations did not utilize a more traditional and effective five spot flood pattern water flood that generally results in a more complete reservoir sweep and oil recovery.

At the time we began our oil and natural gas operations in late September 2003, we purchased essentially all of the working interests and an 80% net revenue interest in the Delhi Field (from the surface to the top of the Massive Anhydride formation, but excepting the Mengel Unit), for approximately $2.8 million, including the assumption of a plugging and abandonment reclamation bond. All but 43 wells in Richland, Franklin and Madison Parishes, Louisiana had been plugged and abandoned and production averaged approximately 18 BOPD with no natural gas being sold due to a lack of natural gas processing and transportation facilities. The best producing well was immediately lost during a periodic sand wash work-over when water from a lower reservoir broke through along the casing exterior and into the producing reservoir.

In October of 2003, we applied an unproven lateral re-entry technology that resulted in no increase in production. In December 2003, we initiated a conventional development program based on re-completion of wells to other reservoirs and restoring non-producing wells to producing status. During 2004, we refurbished a gas injection line, converting it to a gas gathering and sales line, and placed a gas processing plant in the field to begin natural gas production in July of 2004. During 2005, we began a five well development drilling program aimed at reaching mostly proved undeveloped reserves left in primary attic positions. The culmination of these activities caused production to increase from 18 BOPD to a monthly average rate of 145 BOEPD during our peak production month in late 2005.

Concurrent with these activities, we completed internal studies indicating that the reservoirs in the Delhi Holt Bryant Unit, the dominant oil producing reservoirs, had substantial remaining recoverable oil in place. Based on positive CO_2 pilots conducted by Sun Oil in 1985, and favorable rock characteristics shown in multiple cores taken throughout the Delhi Field, we began discussions in late 2004 with potential industry partners skilled in CO_2-EOR recovery methods,.

During this time we also began to acquire royalty and overriding royalty interests that ultimately aggregated 7.4%.

With positive industry reception, and following extended negotiations with three candidates as prospective partners, we accelerated our redevelopment plan in June 2006 by selling a major portion of our Delhi Field interests, in the form of a Farmout, to Denbury Onshore LLC, a subsidiary of the Operator for all of our working interests in the Delhi Holt Bryant Unit and its proved reserves and 75% of our working interests in certain other depths of the Delhi Field (the Delhi Farmout). Important aspects of this transaction include:

- We received approximately $50 million in cash (pre-tax) to redeploy to other projects and repay all of our then outstanding debt.

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- We retained significant participating interests through a reversionary working interest of 25% (20% revenue interest net to us). We expect the value of these interests (along with the separately acquired royalty and overriding royalty interests aggregating 7.4%) will substantially exceed the $50 million cash component of the Delhi Farmout, subject to future oil prices, operating expenses, anticipated EOR performance and project completion by the Operator.

- The Operator committed to install a CO_2-EOR project in the Holt Bryant Unit and expend a minimum additional $100 million on the project over the first 6-1/2 years, subject to penalty payments to us for shortfalls in such expenditures (as of June 2009, the Operator had reported qualifying expenditures substantially in excess of its $100 million minimum capital expenditure obligation). All capital expenditures related to the project are borne by the Operator prior to payout.

- The Operator is the dominant CO_2-EOR operator on the Gulf Coast, currently operating a large number of CO_2-EOR projects and owns naturally occurring CO_2 reserves that we believe to be sufficient to meet the needs of the Delhi project and which have been dedicated to the Delhi project.

- Our reversionary working interest in the CO_2-EOR project is based on a defined $200 million threshold, subject only to expansion of the project through acquisitions, and our reversionary working interest occurs when cumulative project revenues less direct operating costs in the field reach the threshold.

- We further retained a 25% working interest (20% net revenue interest) in certain other depths outside of the Holt Bryant Unit within the Delhi Field, and believe that additional development potential may exist in the shallower depths.

In accordance with SEC rules, our independent reservoir engineer may not consider the assignment of proved reserve status for our EOR resources at Delhi until either (i) first EOR production response occurs, projected by the Operator to occur by mid-year calendar 2010, or (ii) our adoption of the SEC s Modernization rules that are scheduled to become effective on January 1, 2010, which would allow consideration of current technology and other supporting factors before first EOR production response.

Conventional Redevelopment Property

Our Conventional Redevelopment Initiative targets the economic development or redevelopment of primary petroleum resources previously bypassed by industry in mature, historically productive formations, generally due to inadequate technology or commodity prices. This includes development and commercialization of specialized technology for recovering incremental reserves of oil and gas.

Following the closing of our Delhi Farmout in June 2006, we began the process of identifying new Conventional Redevelopment projects. In selecting our candidates:

- We leveraged our staff s extensive experience, gained over many years while employed at UPRC, Anadarko Petroleum Corporation and Columbia Gas Systems in the pioneering of horizontal drilling practices adapted to further develop and produce the Austin Chalk and Georgetown formations in the Giddings Field in central Texas;

- We sought projects that could provide substantial early revenues, production and net cash flows prior to future expected production from the Delhi Field; and

- We sought exposure to both crude oil and natural gas opportunities.

Giddings Field

We began leasing activities in the Giddings Field in December 2006 and acquired 20,899 and 19,069 gross and net acres, respectively, of which 4,299 net acres are developed as of June 30, 2009. In late calendar 2007, we initiated a redevelopment drilling program in the Giddings Field targeting the Austin Chalk and Georgetown formations. As of June 30, 2009, we have placed ten wells into production, including seven wells that were re-entered and re-drilled, one new well that was drilled and two wells that were restored to production through a workover. Our total proved reserves from our properties in the Giddings

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Field are 3,012,445 BOE as of June 30, 2009, down 25% since June 30, 2008, due to a 70% decline in natural gas and a 50% decline in crude oil prices during fiscal 2009. Despite these declines, our total investment of approximately $26 million to date has generated substantial cash flows from 167,136 BOE of production, and we retain a PV-10 of over $35 million plus additional unproved acreage that we believe has significant potential.

Neptune Project

During fiscal 2009, we completed the leasing of 1,503 net acres in our Neptune oil project in South Texas. We believe that previous drilling and production in this field by another operator have established proved reserves and additional potential on infill spacing. We also may apply our specialized oil/water completion technology to further enhance recovery. As of June 30, 2009, we recognized four infill (or downspaced) well locations, with 47,595 Bbls of proved undeveloped reserves from approximately 40 net acres of our holdings. We have identified up to 79 prospective infill drilling locations in the balance of our leasehold.

Tullos Field

On March 3, 2008, we completed the sale of our properties in the Tullos Field, located in LaSalle and Winn Parishes in Louisiana, for gross cash proceeds of approximately $4.6 million.

Producing about 100 gross and 79 net barrels of oil production per day from over 150 producing wells at the time of our divestiture, the Tullos Field required a disproportionate amount of staff effort and vendor services, thereby adversely affecting our ability to develop other projects utilizing our expertise and working capital, particularly in the Giddings Field. The field produced large volumes of water associated with the oil production after being downsized to only two acre spacing. Furthermore, we believe that the potential upside in the Tullos Field was substantially less than that offered in our other projects, where the cash proceeds from the sale of our properties in the Tullos Field could be expected to yield a much higher return. Last, we had completed the testing of our oil-on-water completion technology utilizing the one well we drilled in the Tullos Field and determined that the potential of that technology could be best realized in other fields with greater potential (see Neptune Project).

Unconventional Natural Gas Resource Property

Our Unconventional Natural Gas Resource Initiative targets the use of modern stimulation and completion technologies for the economic development and production of tight gas formations.

Woodford Shale Projects in Oklahoma

Following the closing of our Delhi Farmout in June 2006, we began the process of identifying unconventional natural gas resource projects. We chose two projects in the shallow portion of the Woodford Shale trend in Oklahoma. In choosing these two:

- We are concentrating on projects with relatively low unit development costs that could economically compete with other major gas fields in the region;

- We are leveraging our staff s expertise in both vertical and horizontal drilling and completion of tight gas formations, a prerequisite to successfully exploiting and developing these resources;

- We are focusing on well known gas shale formations;

- We have considered that these projects require large amounts of capital over long periods of time, thereby providing reinvestment opportunities to absorb the substantial cash flows we expect from our other projects, particularly Delhi; and

- We are adding natural gas exposure to balance our substantial crude oil exposure.

We began actively acquiring leases in these two projects in May 2007. At June 30, 2009, we had acquired approximately 24,120 and 17,617 gross and net acres, respectively, across the two projects.

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During the fourth quarter of our 2009 fiscal year, we initiated a program of drilling three wells and re-entering three wells utilizing air drilling in order to test two distinct gas bearing shale formations and one oil sand reservoir. We took one full core in the Woodford Shale, the full results of which are pending. Low pressure acid fractures resulted in commercial gas production in both gas shale formations and the company has initiated a long term production test of both gas shale formations following a pending treatment with a larger hydraulic fracturing with sand proppant.

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. Since March 2005 and into 2008, we sold all of our operated crude oil production to Plains Marketing LP, a crude oil purchaser, at competitive field prices. In January of 2008, we also began selling crude oil to Teppco Crude Oil, LLC, a crude oil gathering, transportation, storage and marketing company. Our agreements with both Plains Marketing LP and Teppco Crude Oil, LLC are under a normal (thirty day evergreen) sales contracts. Subsequent to June 30, 2009, we amended our contracts to sell essentially all of our crude oil to Teppco Crude Oil, LLC. We believe that other crude oil purchasers are readily available.

We sell our natural gas and natural gas liquids from our properties in the Giddings Field, under the terms of normal evergreen sales contracts at competitive prices with DCP Midstream, LP, ETC Texas Pipeline, LTD., and Copano Field Services/Upper Gulf Coast, L.P. Gas sold to DCP and ETC is processed for removal of natural gas liquids, and we receive the proceeds from the sale of the NGL product less a fee and certain operating expenses. The price of natural gas sold to Copano is adjusted upward for the high BTU content. We have no other business relationships with our crude oil, natural gas or natural gas liquids purchasers.

The following table sets forth purchasers of our oil and natural gas that accounted for more than 10% of total revenues for 2009, 2008, and 2007.

	Year Ended June 30,		
Customer	**2009**	**2008**	**2007**
Plains Marketing L.P.	40%	67%	98%
ETC Texas Pipeline, LTD.	36%	26%	
DCP Midstream, LP	16%		

Market Conditions

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

Over the past 25 years, crude oil price fluctuations have been extremely volatile, with crude oil prices varying from less than $10, to in excess of $140 per barrel. Worldwide factors such as geopolitical, macroeconomic, supply and demand, refining capacity, petrochemical production and derivatives trading, among others, influence prices for crude oil. Local factors also influence prices for crude oil and include quality differences, regulation and transportation issues unique to certain producing regions and reservoirs.

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

Competition

The oil and natural gas industry is highly competitive for prospects, acreage and capital. Our competitors include major

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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 us. 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

Crude oil and natural gas drilling and production operations are regulated by various federal, state and local agencies. These agencies issue binding rules and regulations that carry penalties, often substantial, for failure to comply. These regulations and rules require monthly, semiannual and annual reports on production amounts and water disposal amounts, and govern most aspects of operations, drilling and abandonment, as well as crude oil spills. We anticipate the aggregate burden of federal, state and local regulation will continue and potentially increase. We also believe that our present operations materially comply with applicable regulations. To date, such regulations have not had a material effect on our operations, or the costs thereof, other than as described further in Item 3. Legal Proceedings . We do not believe that capital expenditures related to environmental control facilities or other regulatory matters will be material in the near term. We cannot predict what subsequent legislation or regulations may be enacted or what effect it will have on our operations or business.

Insurance

We maintain insurance on our 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 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 our aviation liability insurance coverage is limited to $1 million.

Item 1A. Risk Factors

Risks related to the Company

Operating results from oil and natural gas production may decline.

In the near term, our production is totally dependent on only ten wellbores at our Giddings Field. The targeted reservoirs in the Giddings Field typically experience flush initial production, followed by steep harmonic decline rates that steadily flatten to much shallower decline rates. While the newly drilled producing wells in the Giddings Field substantially increased our net production above historic levels, without further development activities in the Giddings Field, Delhi or our other properties, or without acquisitions of producing properties, our net production of oil and natural gas will decline significantly over time, which could have a material adverse affect on our financial condition.

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

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

Our CO_2-EOR project in the Delhi Field, operated by Denbury Resources Inc., requires significant amounts of CO_2 reserves, the source of which may become unavailable or be curtailed. The Operator controls the operations and CO_2 for the project, and as a result, we have a limited ability to control or influence the development and ultimate success of the project. In order to deliver sufficient quantities of CO_2 from the Operator s reserves from its Jackson Dome Field in Mississippi, a pipeline has been constructed to the Delhi Field. However, substantial capital remains to be invested to fully develop the EOR project and meet all pipeline regulatory requirements. The Operator s failure to manage these and other technical, strategic and logistical risks may render ultimate enhanced recoveries from the planned CO_2-EOR project, if any, to fall short of our expectations in volume and or timing.

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The existing well bores we are re-entering in the Giddings Field may have been originally drilled as far back as the 1980 s. As such, they contain older casing that could be more subject to failure, or the well files, if available, may be incomplete or incorrect. Such problems can result in the complete loss of a well or a much higher drilling and completion cost. Our proved undeveloped locations in the Giddings Field are direct offsets to current or previously producing wells, and there may be unusually long fractures that will connect our well to another producing or depleted well, thus reducing the potential recovery, increasing our drilling costs, or delaying production due to recovery of drilling fluid lost during drilling into the depleted fractures.

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

Our limited operating history and newness of our production makes it difficult to predict future results and increases the risk of an investment in our company.

We commenced our crude oil and natural gas operations in late 2003 and have a limited operating history, particularly in our currently producing fields. All of our current production is the result of recent drilling activities, thus our future production retains substantial variability. Therefore, we face all the risks common to companies in their early stage of development, including uncertainty of funding sources, high initial expenditure levels and uncertain revenue streams, an unproven business model, and difficulties in managing growth. Our prospects must be considered in light of the risks, expenses, delays and difficulties frequently encountered in establishing a new business. Any forward-looking statements in this report do not reflect any possible effects on us from the outcome of these types of uncertainty. Prior to the Delhi Farmout, we had incurred significant losses since the inception of our oil and natural gas operations and we have since resumed incurring losses, except for the quarter ended June 30, 2008, in which we recognized positive operating income. We cannot assure future profitability or success. While members of our management team have previously carried out or been involved with acquisition and production activities in the crude oil and natural gas industry while employed by us and other companies, we cannot assure you that our intended acquisition targets and development plans will lead to the successful development of crude oil and natural gas production or additional revenue.

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

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

Our proprietary technology may not be awarded patent protection and may not result in a commercial service or product.

We have developed and field tested certain artificial lift technology that we hope to commercialize and from which we expect to generate material value. Our success in commercializing the technology will depend upon additional positive field tests, acceptance by industry and our ability to defend the technology from competitors through confidentiality and/or patent protection. Although our patent is pending, there is no assurance that a patent will be awarded or that we will have the ability to exercise patent defense against competitors.

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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 carrying value of proved reserves of crude 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 generally requires pricing future revenues at the un-escalated prices in effect as of the end of our fiscal quarter and requires a write down of the carrying value for accounting purposes if the ceiling is exceeded, even if prices declined for only a short period of time. 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 at the end of any fiscal 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 charge to our earnings but would not impact our cash flow from operating activities.

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

Our estimated proved reserves, revenues, profitability, operating cash flow and future rate of growth are highly dependent on the prices of crude oil, natural gas and NGLs, which are affected by numerous factors beyond our control. Historically, these prices have been very volatile and are likely to remain volatile in the future. A significant and extended downward trend in commodity prices would have a material adverse effect on our revenues, profitability and cash flow, and could result in a reduction in the carrying value of our oil and natural gas properties and the amounts of our estimated proved oil and natural gas reserves. To the extent that we have not hedged our production with derivative contracts or fixed-price contracts, any significant and extended decline in oil and natural gas prices may adversely affect our financial position.

We may be unable to acquire and develop the additional oil and natural gas reserves that are required in order to sustain our business operations.

In general, the volumes of production from crude oil and natural gas properties decline as reserves are depleted with the rate of decline depending on reservoir characteristics. Except to the extent we acquire properties containing proved reserves or conduct successful development activities, or both, our proved reserves will decline. Our future crude oil and natural gas production is, therefore, highly dependent upon our level of success in finding or acquiring additional reserves. Due to the Delhi Farmout, the sale of our properties in the Tullos Field and the decline characteristics of our Giddings wells, our near-term future growth and financial condition are dependent on our ability to develop additional oil and natural gas reserves.

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

The crude oil and natural gas business involves numerous operating hazards such as well blowouts, mechanical failures, explosions, uncontrollable flows of crude oil, natural gas or well fluids, fires, formations with abnormal pressures, hurricanes, flooding, pollution, releases of toxic gas and other environmental hazards and risks. We could suffer substantial losses as a result of any of these events. While we carry general liability, control of well, and operator s extra expense coverage typical in our industry, we are not fully insured against all risks incident to our business.

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

The loss of key personnel could adversely affect us.

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

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

We depend to a large extent on the services of skilled technical personnel to lease, drill, complete, operate and maintain our crude oil and natural gas fields. We do not have the resources to perform all of these services and therefore we outsource many of our requirements. Additionally, as our production increases, so does our need for such services. Generally, we do not have long-term agreements with our drilling and maintenance service providers. Accordingly, there is a risk that any of our service providers could discontinue servicing our crude oil and natural gas fields for any reason. Although we believe that we could establish alternative sources for most of our operational and maintenance needs, any delay in locating, establishing relationships, and training our sources could result in production shortages and maintenance problems, with a resulting loss of revenue to us. We also rely on third-party carriers for the transportation and distribution of our production, the loss of any of which could have a material adverse affect on our operations.

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

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

- our ability to identify and acquire new development or acquisition projects;
- our ability to develop existing properties;
- our ability to continue to retain and attract skilled personnel;
- the results of our development program and acquisition efforts;
- the success of our technologies;
- hydrocarbon prices;
- drilling, completion and equipment prices;
- our ability to successfully integrate new properties; and
- our access to capital.

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

We face strong competition from larger oil and gas companies.

Our competitors include major integrated crude oil and natural gas companies and numerous independent crude oil and natural gas companies, individuals and drilling and income programs. Many of our competitors are large, well-established companies with substantially larger operating staffs and greater capital resources than we have. 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.

The crude oil and natural gas reserves included in this report 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. The reserves discussed in this report 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 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

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reserves based on risk of recovery, and estimates of the future net cash flows expected there from prepared by different engineers or by the same engineers but at different times, may vary substantially. Accordingly, reserve estimates may be subject to downward or upward adjustment. Actual production, revenue and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material. The information regarding discounted future net cash flows included in this report should not be considered as the current market value of the estimated crude oil and natural gas reserves attributable to our properties. As required by the SEC, the estimated discounted future net cash flows from proved reserves are based on prices 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.

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. The unavailability or lack of capacity of such services and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. A shut-in or delay or discontinuance could adversely affect our financial condition. In addition, federal and state regulation of crude oil and natural gas production and transportation could affect our ability to produce and market our crude oil and natural gas on a profitable basis.

Risks Relating to the Oil and Gas Industry

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

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

- unexpected drilling conditions;
- pressure fluctuations or irregularities in formations;
- equipment failures or accidents;
- inability to obtain leases on economic terms, where applicable;
- adverse weather conditions;

- compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs or crews and the delivery of equipment.

Drilling or re-working is a highly speculative activity. Even when fully and correctly utilized, modern well completion techniques such as Hydraulic Fracturing and Horizontal Drilling do not guarantee that we will find crude oil and/or natural gas in our wells. Our future drilling activities may not be successful and, if unsuccessful, such failure would have an adverse affect on our future results of operations and financial condition. We cannot assure you that our overall drilling success rate or our drilling success rate for activities within a particular geographic area will not decline. We may identify and develop prospects through a number of methods, some of which do not include Horizontal Drilling or Hydraulic Fracturing, and some of which may be unproven. The drilling and results for these prospects may be particularly uncertain. Our drilling schedule and costs may vary from our capital budget. The final determination with respect to the drilling of any scheduled or budgeted prospects will be dependent on a number of factors, including, but not limited to:

- the results of previous development efforts and the acquisition, review and analysis of data;

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

We cannot assure you that these projects can be successfully developed or that the wells discussed will, if drilled, encounter reservoirs of commercially productive crude oil or natural gas. There are numerous uncertainties in estimating quantities of proved reserves, including many factors beyond our control.

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

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

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

It is extremely difficult to predict future crude oil and natural gas price movements with any certainty. Declines in crude oil and natural gas prices may materially adversely affect our financial condition, liquidity, ability to finance planned capital expenditures and results of operations. Further, crude oil and natural gas prices do not move in tandem. Because approximately 31% of our reserves at July 1, 2009 are crude oil reserves and 34% are natural gas liquids reserves, we are heavily impacted by movements in crude oil prices, which also influence natural gas liquids prices.

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

Our business plan to redevelop mature crude oil and natural gas resources requires third party oilfield service vendors and various materials such as steel tubulars, which we do not control. Long lead times and spot shortages may prevent us from, or delay us in, maintaining or increasing the production volumes we expect. In addition, if costs for such services and materials increase, it may render certain or all of our projects uneconomic, as compared to the earlier prices we may have assumed when deciding to redevelop newly purchased or existing properties. Further adverse economic outcomes may result from the long lead times often necessary to execute and complete our redevelop plans.

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

Crude oil and natural gas operations are subject to extensive federal, state and local government regulations, which may be

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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 affect on us.

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

President Obama s Proposed Fiscal Year 2010 Budget includes proposed legislation that would, if enacted into law, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether any such changes will be enacted or how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could negatively affect our financial condition and results of operations.

We could be adversely affected by continued recession in the United States or global economy.

The current recessionary economic environment has resulted in lower demand for oil and natural gas, resulting in a decline of commodity prices. If the current recessionary environment continues, reduced demand for petroleum products and lower realized prices, particularly for natural gas, may continue and result in continued or increased operating losses. These factors could negatively impact our operations and may limit our growth.

Risks Associated with Our Stock

Our stock prices has been and may continue to be very volatile.

Our common stock is thinly traded and the market price has been, and is likely to continue to be, highly volatile. For example, during the year prior to June 30, 2009, our stock price as traded on the NYSE Amex ranged from $1.00 to $6.05. The variance in our stock price makes it extremely difficult to forecast with any certainty the stock price at which an investor may be able to buy or sell shares of our common stock. The market price for our common stock could be subject to wide fluctuations as a result of factors that are out of our control, such as:

- actual or anticipated variations in our results of operations;
- naked short selling of our common stock and stock price manipulation;
- changes or fluctuations in the commodity prices of crude oil and natural gas;
- general conditions and trends in the crude oil and natural gas industry; 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 5.9 million shares or approximately 21% of our outstanding common stock. Our former Chairman, and current director of the Board, Mr. Laird Q. Cagan, is a Managing Director of Cagan McAfee Capital Partners, LLC (CMCP). Mr. Eric McAfee, also a Managing Director of

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CMCP, currently owns or controls, directly or indirectly, approximately 4.7 million shares, or approximately 18% of our outstanding common stock, but is neither an officer, employee nor a member of our board of directors. Collectively, the two managing directors of CMCP currently own or control, directly or indirectly, approximately 5.0 million shares, or approximately 18% of our outstanding common stock. Institutional affiliates, including JVL Advisors LLC and Peninsula Capital Management, LP, collectively own approximately 6.4 million shares or approximately 24% of our outstanding common stock. As a result, these holders, could exercise effective control over matters submitted to our stockholders for approval (including the election and removal of directors and any merger, consolidation or sale of all or substantially all of our assets). This concentration of ownership may have the effect of delaying, deferring or preventing a change in control of our company, impede a merger, consolidation, takeover or other business combination involving our company or discourage a potential acquirer from making a tender offer or otherwise attempting to obtain control of our company, which in turn could have an adverse effect on the market price of our common stock.

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

Our common stock is currently thinly traded on the NYSE Amex. In the year prior to June 30, 2009, the actual trading volume in our common stock ranged from zero traded shares of common stock to a high of 523,581 shares of common stock traded, with only 55 days exceeding a trading volume of 50,000 shares. On most days, this trading volume means there is limited liquidity in our shares of common stock. Selling our shares is more difficult because smaller quantities of shares are bought and sold and news media coverage about us is limited. These factors result in a limited trading market for our common stock and therefore holders of our stock may be unable to sell shares purchased, should they desire to do so.

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

Small, relatively unknown companies can achieve visibility in the trading market through research and reports that industry or securities analysts publish. However, to our knowledge, only three independent analysts cover our company. The lack 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 would dilute existing stockholders.

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

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

We do not plan to pay any cash dividends on our common stock.

We have not paid any dividends on our common stock to date and do not anticipate that we will be paying dividends in the foreseeable 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, our anticipated capital requirements and other factors that our board of directors may think are relevant. However, we currently intend for the foreseeable future to follow a policy of retaining all of our earnings, if any, to finance the development and expansion of our business and, therefore, do not expect to pay any dividends on our common stock in the foreseeable future.

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Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Company Location

Our corporate headquarters are located at 2500 CityWest Boulevard, Suite 1300, Houston, Texas. We entered into sublease agreement, effective on March 1, 2007, to rent approximately 8,400 square feet of Class A office space in the Westchase District area in West Houston. The current monthly base rent is $11,507 with the base rent escalating to a monthly base rate of $13,251 in August 2011. The sublease expires by its term on July 1, 2016. Prior to March 1, 2007, we occupied a leased headquarters containing 2,259 square feet in an office building located on the west side of Houston, Texas. In April 2007, this lease expired.

Estimated Proved Oil and Natural Gas Reserves and Future Revenues

We engaged W. D. Von Gonten & Co. (Von Gonten) to prepare an independent report of our proved reserves as of July 1, 2009 (the Reserve Report). Von Gonten also previously prepared independent reports for all of our proved reserves at July 1, 2008, July 1, 2007, July 1, 2006, July 1, 2005, July 1, 2004 and January 1, 2004. Crude oil and natural gas reserves and the estimates of the present value of future net revenues were determined based on current prices and costs.

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

Denominated in equivalent barrels using a six Mcf of gas and 42 gallons of natural gas liquids to one barrel of oil conversion ratio, we recognized proved reserves of 3,060,040 and 4,018,233 at July 1, 2009 and 2008, respectively. Of our proved reserves, natural gas represented 35%, natural gas liquids represented 34%, and crude oil represented 31% as of July 1, 2009, as compared to natural gas of 43%, natural gas liquids of 33% and crude oil of 24% of total proved reserves at July 1, 2008.

The decrease in proved reserves was primarily due to decline in natural gas prices, partially offset by proved reserve additions related to the leasing, redevelopment and drilling activities in our properties in the Giddings Field and our Neptune oil project in South Texas.

The following table sets forth our estimated proved reserves as of July 1, 2009. See Note 17 to the consolidated financial statements, where additional reserve information is provided. The NYMEX spot prices used to calculate estimated revenues were $69.89 per barrel of crude oil and $3.885 per MMbtu of natural gas as of June 30, 2009. The price of natural gas liquids utilized was based on the historical price received versus the NYMEX basis oil price. Pricing differentials were applied to all properties, on an individual property basis, in order to reflect prices actually received at the wellhead. 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.

July 1, 2009

	Proved Developed Producing	Proved Developed Non-producing	Proved Undeveloped	Total Proved Reserves
Crude Oil (Bbls)	104,731		841,217	945,948
NGLs (Bbls)	141,372		912,922	1,054,294
Natural gas (Mcf)	1,106,028		5,252,760	6,358,788
Total (BOE)	430,441		2,629,599	3,060,040
Estimated future net revenues	$ 9,714,324		$ 48,480,128	$ 58,194,452
Estimated future net revenues discounted at 10% (PV-10)	$ 7,640,456		$ 28,185,766	$ 35,826,222

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The following table sets forth our estimated proved reserves as of July 1, 2008. See Note 17 to the consolidated financial statements, where additional reserve information is provided. The unadjusted NYMEX spot prices used to calculate estimated future net revenues were $140.00 per barrel of crude oil and $13.095 per MMBTU of natural gas as of June 30, 2008. The price of natural gas liquids utilized was based on the historical price received versus the NYMEX basis oil price. Pricing differentials were applied to all properties, on an individual property basis, in order to reflect prices actually received at the wellhead. 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.

July 1, 2008

	Proved Developed Producing	Proved Developed Non-producing	Proved Undeveloped	Total Proved Reserves
Crude Oil (Bbls)	96,167		855,874	952,041
NGLs (Bbls)	98,416	11,300	1,200,744	1,310,460
Natural gas (Mcf)	485,701	75,300	9,973,390	10,534,391
Total (BOE)	275,533	23,850	3,718,850	4,018,233
Estimated future net revenues	$ 23,317,256	$ 1,504,919	$ 241,476,331	$ 266,298,506
Estimated future net revenues discounted at 10% (PV-10)	$ 17,423,119	$ 1,372,766	$ 141,457,021	$ 160,252,906

Estimated future net revenues discounted at 10% or PV-10 is a financial measure that is not recognized by accounting principles generally accepted in the United States of America (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. We believe that PV-10 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 of discounted future net cash flows as defined under GAAP.

The following table provides a reconciliation of PV-10 to the Standardized Measure of discounted future net cash flows as shown in Note 17 of the consolidated financial statements.

	For the Years Ended June 30 2009	2008
Estimated future net revenues	$ 58,194,452	$ 266,298,506
10% annual discount for estimated timing of future cash flows	(22,368,230)	(106,045,600)
Estimated future net revenues discounted at 10% (PV-10)	35,826,222	160,252,906
Estimated future income tax expenses discounted at 10%	(12,276,431)	(63,180,265)
Standardized Measure of discounted future net cash flows	$ 23,549,791	$ 97,072,641

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Sales Volumes, Average Sales Prices and Average Production Costs

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

	Year Ended June 30, 2009			Year Ended June 30, 2008			Year Ended June 30, 2007		
Product	**Volume**		**Price**	**Volume**		**Price**	**Volume**		**Price**
Crude oil (Bbls)	36,026	$	76.26	29,466	$	99.03	28,800	$	64.82
Natural gas liquids (Bbls)	44,125	$	36.83	10,639	$	63.02			
Natural gas (Mcf)	323,301	$	5.33	69,051	$	9.67			

Average production costs, including production taxes, per unit of production (using a six to one conversion ratio of Mcf s to barrels) were approximately $11, $25 and $49 per BOE for the years ended June 30, 2009, 2008 and 2007, respectively.

The increases in volumes were attributable to the development of our properties in the Giddings Field, which accounted for almost 100 percent of our production during the year ended June 30, 2009. Our production in the Giddings Field began late in the third fiscal quarter of the year ended June 30, 2008. Our properties in the Tullos Field, which were sold on March 3, 2008, accounted for 35% of total sales volumes for the year ended June 30, 2008, and almost 100 percent of our production for the year ended June 30, 2007.

Productive Wells and Developed Acreage

Our developed acreage at June 30, 2009 totaled 4,299 net acres in the Giddings Field, consisting of a 100% working interest in ten producing wells.

Our developed acreage at June 30, 2008 totaled 3,469 net acres, all of which is in the Giddings Field, consisting of a 100% working interest in seven producing wells. Proved undeveloped acreage included twenty-seven proved drilling locations.

At June 30, 2007, we owned working interests in 260 net and gross wells consisting of 158 crude oil wells, 23 salt water disposal wells and 93 shut-in wells with uncertain future utility, all located in the Tullos Field in Louisiana. Our properties in the Tullos Field were sold on March 3, 2008.

Undeveloped Acreage

Proved undeveloped acreage includes twenty-one proved drilling locations in the Giddings Field and four newly added proved drilling locations in our Neptune oil project in South Texas.

The reduction of six proved locations from the 27 proved locations as of the end of fiscal 2008 includes two wells drilled and placed on production, two locations that were consolidated into one, and five locations that became uneconomic due to much lower natural gas wellhead prices at year end 2009. The reductions were partially offset by the addition of two proved locations. Additional drilling locations are associated with our acreage, but require further leasing, step out drilling, and/or an increase in commodity prices before being considered for inclusion in our proved reserves.

As of June 30, 2009, we held approximately 55,952 gross and 37,340 net undeveloped acres in the Gulf Coast and Mid-Continent regions of the United States, as follows:

Field/Area	**Gross Acreage**	**Net Acreage**
Giddings Field, Texas	16,600	14,811
Woodford, Oklahoma	24,120	17,617
Neptune (Lopez Field), South Texas	1,596	1,503
Delhi Field, Louisiana *	13,636	3,409
Total	55,952	37,340

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* Includes from the surface of the Earth to the top of the Massive Anhydride, less and except the Delhi Holt Bryant CO_2 and Mengel Units. With respect to the Delhi Holt Bryant Unit, currently scheduled for CO_2-EOR operations within this same acreage, we currently own royalty and overriding royalty interests aggregating approximately 7.4%. Separately, we own a 25% working interest (20% net revenue interest) that will revert to us, as, if and when payout occurs, as defined. We are not the operator of the Delhi CO_2-EOR project.

For more complete information regarding current year activities, including crude oil and natural gas production, refer to Management s Discussion and Analysis of Financial Condition and Results of Operations.

Item 3. Legal Proceedings

None.

Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of our security holders, through solicitation of proxies or otherwise, during the fourth quarter ended June 30, 2009.

PART II

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

Common Stock

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

We initiated trading of our common stock on the OTC Bulletin Board in May 2004, under the symbol NGSY . On July 17, 2006 we qualified for trading on the American Stock Exchange. The American Stock Exchange was acquired by the NYSE Euronext (NYX) in 2008 and is now known as NYSE Amex. The following table shows, for each quarter of fiscal year 2009 and 2008, the high and low sales prices for EPM as reported by the NYSE Amex.

NYSE Amex

2009:		**High**		**Low**
Fourth quarter ended June 30, 2009	$	3.13	$	1.85
Third quarter ended March 31, 2009	$	1.99	$	1.17
Second quarter ended December 31, 2008	$	3.06	$	1.00
First quarter ended September 30, 2008	$	6.05	$	2.60

2008:		**High**		**Low**
Fourth quarter ended June 30, 2008	$	7.15	$	4.08
Third quarter ended March 31, 2008	$	5.85	$	3.40
Second quarter ended December 31, 2007	$	5.60	$	2.90
First quarter ended September 30, 2007	$	3.24	$	2.12

Holders

As of June 30, 2009, there were 26,530,317 shares of common stock issued and outstanding, held by approximately 2,386 holders of record.

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Dividends

We have never declared or paid any cash dividends with respect to our common stock. We anticipate that we will retain future earnings for use in the operation and expansion of our business and do not anticipate paying cash dividends on the common stock in the foreseeable future. Any future determination with regard to the payment of dividends will be at the discretion of the board of directors and will be dependent upon our future earnings, financial condition, applicable dividend restrictions and capital requirements and other factors deemed relevant by the board of directors.

Securities Authorized For Issuance Under Equity Compensation Plans

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)		Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	4,448,320(1)	$	1.90	1,006,461
Equity compensation plans not approved by security holders	1,385,558(2)	$	1.53	
Total	5,833,878	$	1.81	1,006,461

(1) On May 26, 2004, we, as Reality Interactive, Inc., executed an Agreement and Plan of Merger with Natural Gas Systems, Inc., a Delaware corporation (the Merger). In connection with the Merger, we assumed the obligations of 600,000 stock options under our acquired subsidiary s 2003 Stock Option Plan. As of June 30, 2009, 500,000 shares remain issuable upon exercise of stock options under the 2003 Stock Option Plan and no further options shall be issued there-under. As of June 30, 2009, there were 3,948,320 shares of common stock issuable upon exercise of outstanding stock options and 545,219 shares of common stock issued directly under the 2004 Stock Plan, leaving 1,006,461 shares of common stock available for issuance.

(2) In addition to assuming certain obligations listed in footnote 1 above, in connection with the Merger, we also assumed outstanding warrants to purchase shares of common stock issued in connection with arranging the merger and in connection with capital raising. Total warrants outstanding as of June 30, 2009 related to these activities were 348,058 with a weighted average exercise price of $1.46. Also included were 1,037,500 warrants with a weighted average exercise price of $1.56 issued in connection with employment and or compensation arrangements, including a warrant to purchase 287,500 shares of common stock in connection with Mr. Herlin s employment agreement with the Company, a warrant to purchase 200,000 shares in connection with Mr. Mazzanti s employment agreement with the Company, a warrant to purchase 400,000 shares of common stock in connection with Mr. Herlin s annual performance incentives, including warrants in lieu of cash bonus, and a warrant to purchase 150,000 shares of common stock in connection with Sterling McDonald s annual performance incentives, including warrants in lieu of cash bonus.

Recent Sales of Unregistered Securities

None.

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Item 6. Selected Financial Data

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

	Year Ended June 30				
	2009	2008	2007	2006 (as restated)	2005
Income Statement Data					
Revenues	$ 6,095,183	$ 4,256,128	$ 1,866,878	$ 2,861,414	$ 1,635,187
Lease operating expense	$ 1,281,989	$ 1,255,787	$ 1,352,907	$ 1,698,044	$ 853,052
Production taxes	$ 158,794	$ 90,252	$ 62,426	$ 86,562	$ 68,386
Depreciation, depletion, and amortization	$ 2,461,162	$ 903,214	$ 291,150	$ 407,467	$ 260,124
Accretion expense	$ 37,601	$ 20,196	$ 17,319	$ 27,716	$ 21,824
General and administrative expense (G&A) (excluding stock-based compensation)	$ 3,490,466	$ 3,705,751	$ 2,878,107	$ 2,279,518	$ 1,513,663
G&A: Stock-based compensation	$ 2,405,900	$ 1,791,486	$ 1,613,493	$ 546,567	$ 707,117
Gain from sale of oil and natural gas properties	$	$	$	$ 45,325,468	$
Income (loss) from operations	$ (3,740,729)	$ (3,510,558)	$ (4,348,524)	$ 43,141,008	$ (1,788,979)
Other income (expense), net	$ 122,272	$ 854,130	$ 1,899,460	$ (2,434,867)	$ (375,592)
Income tax provision (benefit)	$ (1,016,864)	$ (1,085,454)	$ (638,853)	$ 15,007,775	$
Net income (loss)	$ (2,601,593)	$ (1,570,974)	$ (1,810,211)	$ 25,698,366	$ (2,164,571)
Earnings (loss) per common share - Basic	$ (0.10)	$ (0.06)	$ (0.07)	$ 1.03	$ (0.09)
Earnings (loss) per common share - Diluted	$ (0.10)	$ (0.06)	$ (0.07)	$ 1.01	$ (0.09)
Cash Flows Data					
Operating Activities:					
Before changes in operating assets and liabilities	$ 3,070,310	$ 3,740,878	$ (11,865,115)	$ (3,893,417)	$ (1,096,624)
Changes in operating assets and liabilities	2,884,468	(4,597,678)	(2,626,933)	3,156,213	19,089
Cash provided by (used in) operating activities	5,954,778	(856,800)	(14,492,048)	(737,204)	(1,077,535)
Investing Activities:					
Development of oil and natural gas properties	(8,063,465)	(11,187,291)	(417,964)	(2,611,369)	(503,394
Acquisition of oil and natural gas properties	(2,603,098)	(8,789,501)	(1,918,757)	(1,448,239)	(1,554,149)
Proceeds from sale of oil and natural gas properties		4,452,450	155,378	49,993,134	
Purchases of certificates of deposit	(1,757,312)				
Cash in qualified intermediary account for like-kind exchanges			34,662,368	(34,662,368)	
Other	(33,350)	(93,596)	(120,050)	551,467	(721,080)
Cash provided by (used in) investing activities	(12,457,225)	(15,617,938)	32,360,975	11,822,625	(2,778,623)
Financing Activities:					

Purchase of treasury stock	(882,022)				
Payments on notes payable				(5,634,654)	(1,725,167)
Proceeds from notes payable				1,003,563	3,526,754
Equity transactions	130	76	(15,532)	890,529	4,235,428
Other	3,823				
Cash provided by (used in) financing activities	(878,069)	76	(15,532)	(3,740,562)	6,037,015
Increase (decrease) in cash and cash equivalents	$ (7,380,516)	$ (16,474,662)	$ 17,853,395	$ 7,344,859	$ 2,180,857

	June 30, 2009	June 30, 2008	June 30, 2007	June 30, 2006 (as restated)	June 30, 2005
Balance Sheet Data					
Total current assets	$ 8,873,786	$ 17,801,070	$ 28,921,518	$ 10,321,359	$ 3,212,558
Total assets	$ 37,828,823	$ 40,365,848	$ 34,905,992	$ 48,957,958	$ 9,465,224
Total current liabilities	$ 1,237,904	$ 4,171,048	$ 1,596,558	$ 3,476,727	$ 613,326
Total liabilities	$ 6,072,229	$ 7,362,114	$ 2,122,846	$ 15,962,562	$ 3,953,124
Temporary equity (351,335 shares of common stock outstanding at June 30, 2006)	$	$	$	$ 790,500	$
Stockholders equity	$ 31,756,594	$ 33,003,734	$ 32,783,146	$ 32,204,896	$ 5,512,100
Common stock outstanding	26,530,317	26,870,439	26,776,234	26,300,670	24,774,606

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	Quarter Ended June 30, 2009	March 31, 2009	December 31, 2008	September 30, 2008	June 30, 2008
Revenues					
Crude oil	$ 409,546	$ 351,684	$ 407,194	$ 1,579,070	$ 1,253,478
Natural gas liquids (NGLs)	283,434	350,891	235,293	755,445	558,736
Natural gas	290,971	461,889	389,295	580,471	544,290
Total operating revenues	983,951	1,164,464	1,031,782	2,914,986	2,356,504
Operating Expense					
Lease operating expense (LOE)	376,969	255,710	313,406	335,904	284,099
Production taxes	21,272	29,750	21,776	85,996	44,021
Depreciation, depletion, and amortization (DD&A)	552,153	759,836	504,291	644,882	530,569
Accretion expense	13,149	12,591	6,124	5,737	3,540
G&A (excluding stock-based compensation) (1)	413,132	1,058,117	1,078,102	941,115	954,771
G&A: Stock-based compensation (2)	760,365	537,285	584,525	523,725	480,043
Total operating expense	2,137,040	2,653,289	2,508,224	2,537,359	2,297,043
Operating income (loss)	(1,153,089)	(1,488,825)	(1,476,442)	377,627	59,461
Interest income, net	22,820	8,024	17,782	73,646	81,295
Net income (loss) before income taxes	$ (1,130,269)	$ (1,480,801)	$ (1,458,660)	$ 451,273	$ 140,756
Sales volumes per day					
Oil (Bbls)	78.9	97.90	77.2	139.5	105.4
NGL (Bbls)	113.1	165.8	83.5	120.3	95.0
Natural gas (Mcf)	934.1	1232.7	706.2	664.6	584.0
Total (BOE)	347.7	469.2	278.4	370.5	297.7
Average sales price					
Oil per Bbl	$ 57.02	$ 39.47	$ 57.37	$ 123.03	$ 130.71
NGL per Bbl	27.55	23.25	30.63	68.29	64.63
Natural gas per Mcf	3.42	4.12	5.99	9.49	10.24
Total per BOE	31.10	27.27	40.29	85.51	86.98
Per BOE					
LOE and production taxes	12.59	6.69	13.09	12.38	12.11
DD&A	17.45	17.80	19.69	18.92	19.58
Accretion expense	0.42	0.29	0.24	0.17	0.13
G&A (excluding stock-based compensation) (1)	13.06	24.78	42.10	27.61	35.24
G&A: Stock-based compensation (2)	24.03	12.58	22.83	15.36	17.72
Total operating expense	67.55	62.14	97.94	74.43	84.78
Operating (loss) income	$ (36.45)	$ (34.87)	$ (57.65)	$ (11.08)	$ 2.20
Net income (loss) before income taxes	$ (35.72)	$ (34.68)	$ (56.96)	$ (13.24)	$ 5.20

(1) G&A for the quarter ended June 30, 2009, includes the reversal of accrued bonuses of $509,891 ($16.12 per BOE of production), due to the decision to issue common stock to employees in lieu of a cash bonus.

(2) G&A: Stock-based compensation for the quarter ended June 30, 2009, includes a charge of $370,440 ($11.71 per BOE of production), related to the payment of 2009 bonuses through the issuance of common stock.

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

Executive Overview

General

We are a petroleum company engaged primarily in the acquisition, exploitation and development of properties for the production of crude oil and natural gas. We acquire known, underdeveloped oil and natural gas resources and exploit them through the application of capital and technology to increase production, ultimate recoveries, or both.

Our strategy is intended to generate scalable development opportunities at normally pressured depths, exhibiting relatively low completion risk, generally longer and more predictable production lives, less expenditures on infrastructure and lower operational risks.

Within this overall strategy, we pursue three specific initiatives:

I	Enhanced oil recovery (EOR), using miscible and immiscible gas flooding;
II	Conventional redevelopment of bypassed primary resources within mature oil and natural gas fields utilizing modern technology and our expertise; and
III	Unconventional gas resource development, using modern stimulation and completion technologies.

Our most significant asset is within our EOR Initiative in the 13,636 acre Delhi Field, located in northeast Louisiana. Our non-operated interests consist of 7.4% in overriding and mineral royalty interests and a 25% after pay-out reversionary working interest in the Delhi Field Holt Bryant Unit, along with a 25% working interest in certain other depths in the Delhi Field resulting from the Farmout we completed on June 12, 2006 with Denbury Onshore LLC, a subsidiary of Denbury Resources Inc. (the Operator) (the Delhi Farmout). The Holt Bryant Unit is currently being redeveloped by the Operator, using CO_2 enhanced oil recovery technology and a dedicated portion of the Operator s proved CO_2 reserves in the Jackson Dome, located approximately 100 miles east of Delhi. According to the Operator in a public filing dated August 4, 2009, injection of CO_2 is expected to commence by the fourth quarter of calendar 2009, with initial oil production response expected by mid-year calendar 2010.

Since our closing of the Delhi Farmout, we have focused on developing projects in our other initiatives, particularly through conventional redevelopment of bypassed resources in the Giddings Field using horizontal drilling methods, the leasing of unconventional gas shale projects in the shallower portion of the Woodford Shale Trend in Oklahoma and the leasing of Neptune, an oil infill drilling project in South Texas.

We are funding our ongoing development from our working capital resources and from net cash flows from our properties in the Giddings Field; our cash flows from the Delhi Project also will be used to fund full development of our projects and other new projects. We also may utilize project financing in the future.

Our long term strategy and primary focus continue to be on increasing share value through the identification and acquisition of resources and conversion of those resources into proved reserves through our expertise and technology.

Highlights for our fiscal year 2009

Projects

- **The CO_2 Pipeline to the Delhi Field has been completed.** On May 5, 2009, the operator reported that the 78 mile Delta Pipeline from Tinsley Field to the Delhi Field has been completed and tested, allowing CO_2 injection to proceed by calendar year end, following full regulatory approval. As of June 30, 2009, the Operator has reported that $256.2 million of capital expenditures have been made on the CO_2-EOR project, excluding capitalized interest and the $50 million paid to us.

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- **We re-entered and drilled new laterals in two wells at Giddings.** The Hilton Yegua #1 and the Pearson #1 were completed and placed on production during January 2009. The average initial 8 day rate for the two wells was 450 gross BOED each, and they were averaging 120 gross BOED each during August of 2009. We own a 100% working interest and approximately 79% revenue interest in the two wells.

- **We successfully field tested our proprietary lift technology at Giddings.** The first well we re-entered and drilled horizontally in Giddings, the Donella #1, was also our poorest producer due to previous depletion of the zone by an offset well. After several months of production, the well became incapable of commercial production on rod pump. During June 2009, we re-entered the Donella to install and test our proprietary artificial lift technology. Commercial production was successfully re-established and has steadily improved over its first two months of production.

- **We initiated and completed leasing of our Neptune oil project in South Texas and made preparations for drilling.** We completed the leasing of approximately 1,500 net acres, establishing proved reserves on four locations and identifying another 100 potential infill drilling locations. Historical production in this field by a previous operator demonstrated that substantial commercial reserves can be generated through drilling on infill spacing. We expect to apply in the future the oil/water completion technology here that we previously developed and tested in the Tullos Field in Louisiana with the potential of increasing the profitability and commerciality of the infill wells.

- **We began proof of concept drilling in our shallow Woodford Gas Shale Project.** We initiated the drilling of three test wells and re-entry of four test wells, all vertical tests with light acid hydraulic fracturing, on our acreage in Wagoner County in Oklahoma. Our objective is to prove that shallow vertical wells in our lease area can be economically competitive with other regional gas plays. We are awaiting core results and more extensive production tests to establish the production curves necessary for full development in calendar 2010.

Operations

- **Sales volumes increased 160% in fiscal 2009 versus fiscal 2008.** Our increase in sales volumes for the year were solely attributable to our production in the Giddings Field. Our properties in the Tullos Field, which were sold on March 3, 2008, accounted for approximately 35% of total sales volumes for our fiscal year ended June 30, 2008.

- **We exited fiscal 2009 at a combined rate of approximately 364 net BOE per day**. Production during the year was enhanced by the drilling and completion of two re-entries, installing gas lift on two wells, installing our proprietary artificial lift technology on one well and adding a new well to production through a workover and acid treatment.

- **We lowered our field income break-even point by 31% over fiscal 2008 and 51% over fiscal 2007.** During the year ended June 30, 2009, lifting costs (lease operating expense and production taxes, on a combined per unit of sales basis) were $10.69 and our depletion rate was $18.07 per BOE, equaling a field income break-even point of $28.76 per BOE. This compares to lifting costs of $25.39 and a depletion rate of $16.44 per BOE, equaling a field income break-even point of $41.83 per BOE we experienced during fiscal 2008 and lifting costs of $49.14 and a depletion rate of $9.68 per BOE, equaling a field income break-even point of $58.82 per BOE we experienced during fiscal 2007. During the quarter ended September 30, 2007, where primarily all our production was from our properties in the Tullos Field, lifting costs and depletion averaged $46.61 and $15.70 per Bbl of crude oil, respectively.

- **The product prices we received declined 45% in fiscal 2009 versus fiscal 2008.** During the year ended June 30, 2009, the average price we received was $45.47 per BOE, as compared to $82.46 per BOE during the year ended June 30, 2008, and $31.10 per BOE during the three months ended June 30, 2009 versus $86.98 for the three months ended June 30, 2008. However, most of the capital expenditures, including the drilling of the two re-entry wells in Giddings, occurred before most of the substantial reductions in oil field service prices that followed the decline in commodity prices.

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Finances

- **We ended the year with $7.6 million of working capital, compared to $13.6 million at June 30, 2008.** At June 30, 2009, working capital included $6.0 million of cash and cash equivalents and short-term certificates of deposit, and $2.1 million of recoverable income taxes arising from current year tax losses being carried back to a prior tax year. Early in fiscal 2009, we reduced our $19 million capital budget to under $10 million. We finished fiscal 2009 incurring $8.6 million (not including $0.5 million related to amounts capitalized due to asset retirement obligations) in capital expenditures for oil and natural gas leasehold and development costs.

- **We repurchased 788,200 shares of our common stock at an average price of $1.10 per share, plus $0.02 per share transaction costs**. We believe that our potential underlying asset value per share is substantially greater than the price we paid for the shares. At this time, we currently have no plan to repurchase more common shares.

- **We protected our short-term investments during difficult credit market conditions.** We continued to avoid higher risk credit instruments, relying instead upon lower yielding short-term U.S. Treasury money market funds. During the second quarter of fiscal 2009, we redeployed some of our cash and cash equivalents into certificates of deposit that matured within a year and that are fully insured by the FDIC.

- **Despite substantially lower oil and gas prices that resulted in a loss of 1MMBOE of PUD reserves, we did not have to impair the net book value of our assets.** Fiscal year end NYMEX spot prices for crude oil declined 50% and natural gas declined 70% year over year, from $140.00 to $69.89 and from $13.095 to $3.885, respectively. During fiscal 2009, our proved reserves decreased 24% from 4.02 MMBOE to 3.06 MMBOE, due primarily to the decline in the price of natural gas, partially offset by reserve additions through leasing and development activities in the Giddings Field and in our Neptune oil project in South Texas. Despite the decline in commodity prices and their affect on our proved reserves as of June 30, 2009, our ceiling as calculated in our June 30, 2009 ceiling test remains approximately $11.4 million greater than the net book value of our oil and natural gas properties, net of related deferred income taxes.

- **Non-cash stock-based compensation expense of $2.4 million comprised over forty percent of total general and administrative expenses during the fiscal year ended June 30, 2009.** Non-cash stock-based compensation expense remains an important part of our total compensation program to help motivate and retain high performing employees and consultants, in addition to conserving our cash resources.

- **We settled the Thomas, et al lawsuit at Delhi.**

- **We remained debt free.** All of our expenditures were funded solely by working capital and we ended the year with no funded debt. We continue to have no short or long term liabilities other than payables, deferred income taxes and asset retirement obligations incurred in the ordinary course of business.

Looking forward into 2010

We will focus on:

Selective low cost testing and development of our portfolio properties.

- **Upgrade our shallow multi-pay shale gas reserves.** We plan to continue testing wells in two gas shale reservoirs in Wagoner County, OK in order to establish predictable peak rates and decline curves. Later in the fiscal year, market conditions permitting, we plan to re-enter a well in our mid-depth project in Haskell County, OK to begin testing two gas shale reservoirs expected between 4,000 and 5,000 depth.

- **Pursue commercial joint ventures utilizing our proprietary artificial lift technology.** Based on tests results in our Donella #1, we believe this technology could re-establish production in many wells throughout the Giddings Field, and potentially other fields developed with horizontal wells. We intend to approach producers to pool our technology and expertise with the intent of gaining an interest in new production re-established with our technology.

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- **Establish production at Neptune**. We have initiated development in our 100% owned Neptune oil project in South Texas that will include drilling two infill producers and one injection well, thus potentially upgrading additional proved reserves while adding oil production.

- **Conduct workovers in Giddings to generate net production to cover our overhead.** We expect to carry out several workovers on certain wells, including one currently nonproducing well we inherited in our leasing, to partially offset normal production declines and generate sufficient cash flows to offset corporate cash overhead.

- **Solicit joint venture(s) to drill Giddings PUD locations.** If natural gas prices recover and oil prices remain stable during fiscal year 2010, we may begin drilling in the Giddings Field or enter into a joint venture to conduct drilling of our PUD locations.

***Continued progress in our Delhi EOR project*.**

- **Delhi operator plans to initiate CO_2 injection by calendar 2009 year end.**

- **Delhi operator expects first oil production by mid-calendar 2010.**

- **Establish proved reserves at Delhi.** Under current SEC rules, proved reserves cannot be assigned to our Delhi EOR property until first EOR production response, projected by the Operator to occur by mid-year calendar 2010. Alternatively, the SEC s Modernization rules that are scheduled to become effective on January 1, 2010, state that reservoir engineers can consider other relevant factors in assigning proved reserves to EOR projects, including current technology, the results of field pilot tests and EOR projects in geologically comparable fields, all of which we believe are characteristics of the EOR project at Delhi.

Continued conservative financial management.

- **Emphasizing long-term share value over near-term earnings during the current period of low natural gas prices.**

- **Retain financial strength and flexibility to assure we obtain proper value of our core assets.**

- **Primarily use internally generated funds and our working capital for fiscal 2010 goals,** while looking to joint ventures and project financing for additional growth when capital and natural gas market conditions improve.

Liquidity and Capital Resources

At June 30, 2009, our working capital was $7.6 million and we continued to be debt free. This compares to working capital of $13.6 million at June 30, 2008. The decrease in working capital of $6.0 million since June 30, 2008 was due primarily to investments of $8.6 million in oil and natural gas properties, consisting of $2.3 million in leasehold acquisition costs and $6.3 million in development activities. We also repurchased 788,200 shares of our common stock for $0.9 million and spent approximately $0.2 million on retiring certain asset retirement obligations and acquiring other property and equipment. These transactions, which reduced our working capital, were partially offset by EBTDA of $1.3 million, income taxes recoverable of $2.1 million from the carry-back of our 2009 income tax loss, and a reclassification of a $0.3 million certificate of deposit from other assets to current assets. The most directly comparable GAAP financial measure to EBTDA is Net loss before income tax benefit. EBTDA is reconciled to our $3.6 million Net loss before income tax benefit by adding back non-cash charges of $4.9 million related to stock-based compensation, depreciation, depletion, and amortization, and accretion on asset retirement obligations (charges that had no impact on our working capital).

Cash flows provided by operating activities for the year ended June 30, 2009 were $6.0 million. Cash flows provided by operations includes cash proceeds of $7.3 million from oil and natural gas production primarily from our properties in the Giddings Field, cash proceeds of $0.1 million from interest income and cash proceeds of $4.1 million from income tax refunds, primarily from our 2008 tax year net operating loss carry-back. Sources of cash were offset by $5.5 million of cash payments for operating activities, including lease operating expenses, production taxes, salaries and wages and general administrative expense.

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In comparison, $0.9 million of cash was used in operations during the year ended June 30, 2008, which includes $2.8 million of cash proceeds from oil and natural gas production ($1.7 million from our properties in the Tullos Field, which we sold during the third quarter of fiscal 2008, and $1.1 million primarily from our properties in the Giddings Field) and cash proceeds from interest income of $0.9 million. These 2008 cash sources were offset by $4.6 million of cash payments for operating activities, including lease operating expenses, production taxes, salaries and wages and general administrative expense.

Cash flows used in investing activities totaled $12.5 million during the year ended June 30, 2009, which includes the purchase of short-term certificates of deposit of $1.8 million. Our remaining investing activities of $10.7 million were primarily for development activities in the Giddings Field and leasehold acquisitions in the Giddings Field, our Woodford Shale projects in Oklahoma and our Neptune oil project in South Texas. The $10.7 million includes net payments on accounts payable relating to expenditures for oil and natural gas properties of $2.1 million from June 30, 2008, thus we incurred $8.6 million of capital expenditures for oil and natural gas properties during this fiscal year.

Cash flows used in investing activities totaled $15.6 million during the year ended June 30, 2008. Cash of $20.0 million was used for investments to acquire and develop oil and natural gas property interests and other property and equipment, primarily for investments in oil and natural gas properties at the Giddings Field. The $20.0 million does not include the $1.6 million net increase in accounts payable related to capital expenditures on oil and natural gas properties from June 30, 2007 to June 30, 2008, thus we incurred $21.6 million of capital expenditures for oil and natural gas properties during the 2008 fiscal year. The sale of our properties in the Tullos Field partially offset our development and acquisition activities by providing net cash proceeds of $4.4 million during the year ended June 30, 2008.

Cash flows used in financing activities for the year ended June 30, 2009 were $0.9 million. On October 30, 2008, we repurchased 788,200 shares of common stock at an average price of $1.10 per share plus $0.02 in transaction costs from an unaffiliated accredited investor.

There were no significant cash flows from financing activities during the fiscal year ended June 30, 2008.

We incurred $8.6 million of capital expenditures for oil and natural gas leasehold and development costs during year ended June 30, 2009, plus an additional $0.5 million related to recognition of asset retirement obligations. The $8.6 million of incurred capital expenditures in fiscal 2009, $2.3 million was for leasehold acquisitions and $6.3 million for development activities. Development activities were primarily in the Giddings Field, with $0.3 million in test drilling in our Woodford Shale acreage. Leasehold costs were for properties in the Giddings Field, our Woodford Shale projects in Oklahoma and our Neptune oil project in South Texas.

We incurred approximately $21.6 million in capital expenditures for oil and natural gas leasehold and development costs during year ended June 30, 2008, plus an additional $0.2 million related to the recognition of asset retirement obligations. The $21.6 million in capital expenditures in fiscal 2008 included $8.6 million for leasehold acquisitions and $13.0 million for development costs, primarily in the Giddings Field.

Based on our current plans, we expect capital expenditures of approximately $3.0 million during 2010 for:

- Development of our first two infill oil PUDs at our Neptune South Texas properties to prospectively add production and additional proved reserves there;

- Extended testing of our shallow multi-reservoir gas shale project in Eastern Oklahoma;

- Commercialization and joint venture(s) of our proprietary artificial lift technology, with the goal of sharing in additional production from third-party operator s incapable wells;

- Improvement of Giddings economics through production and cost efficiencies, focusing on workovers to optimize production and the drilling of a saltwater disposal well to reduce lifting costs; and

- Selected opportunistic leasing in and around our existing projects.

We expect to fund our fiscal 2010 goals with internally generated funds and our working capital, while looking to joint ventures and project financing for additional growth, when capital and natural gas market conditions improve.

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Due to our positive working capital, cash flows from producing properties, no debt and no near term expiring leases, we believe we have the ability to fund or further adjust our capital expenditure budget to capture select opportunities that may arise for the benefit of our shareholders, without the need of additional financing. Therefore, we believe that our current sources of liquidity are sufficient to fund our ongoing cash requirements.

Results of Operations

Year ended June 30, 2009 compared with the year ended June 30, 2008

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

	Year Ended June 30 2009	2008	Variance	% change
Sales Volumes, net to the Company:				
Crude oil (Bbl)	36,026	29,466	6,560	22%
NGLs (Bbl)	44,125	10,639	33,486	315%
Natural gas (Mcf)	323,301	69,051	254,250	368%
Crude oil, NGLs and natural gas (BOE)	134,035	51,614	82,421	160%
Revenue data:				
Crude oil	$ 2,747,494	$ 2,918,127	$ (170,633)	(6)%
NGLs	1,625,063	670,434	954,629	142%
Natural gas	1,722,626	667,567	1,055,059	158%
Total revenues	$ 6,095,183	$ 4,256,128	$ 1,839,055	43%
Average price:				
Crude oil (per Bbl)	$ 76.26	$ 99.03	$ (22.77)	(23)%
NGLs (per Bbl)	36.83	63.02	(26.19)	(42)%
Natural gas (per Mcf)	5.33	9.67	(4.34)	(45)%
Crude oil, NGLs and natural gas (per BOE)	$ 45.47	$ 82.46	$ (36.99)	(45)%
Expenses (per BOE)				
Lease operating expenses and production taxes	$ 10.69	$ 25.39	$ (14.70)	(58)%
Depletion expense on oil and natural gas properties (a)	$ 18.07	$ 16.44	$ 1.63	10%

(a) Excludes depreciation of office equipment, furniture and fixtures, and other of $38,965 and $54,668, for the year ended June 30, 2009 and 2008, respectively.

Net loss. For the year ended June 30, 2009, we reported a net loss of $2,601,593, or $0.10 loss per share (which includes $2,405,900 of non-cash stock-based compensation expense) on total oil and natural gas revenues of $6,095,183. This compares to a net loss of $1,570,974, or $0.06 loss per share (which includes $1,791,486 of non-cash stock-based compensation expense) on total oil and natural gas revenues of $4,256,128 for the year ended June 30, 2008. An increase in our revenues of $1,839,055 was offset by increases in operating costs of $2,069,226 (primarily related to an increase in stock-based compensation and depreciation, depletion, and amortization), a decrease in interest income of $731,858, and a decrease in our income tax benefit of $68,590. Additional details of the components of net loss are explained in greater detail below.

Sales Volumes. Crude oil, NGLs, and natural gas sales volumes, net to our interest, for the year ended June 30, 2009 increased 160% to 134,035 BOE, compared to 51,614 BOE for the year ended June 30, 2008. The increase in sales volumes is due to production of crude oil, NGLs and natural gas from our properties in the Giddings Field. Production in our Giddings Field began late in our third fiscal quarter for the year ended June 30, 2008. Our properties in the Tullos Field, which were sold on March 3, 2008, accounted for 35% of total sales volumes for the year ended June 30, 2008.

Oil, NGLs and Natural Gas Revenues. Crude oil, NGLs and natural gas revenues for the year ended June 30, 2009 increased 43% from the year ended June 30, 2008. This was due to an increase in sales volumes of crude oil, NGLs, and natural gas during the year ended June 30, 2009 from our properties in the Giddings Field. Production in our Giddings Field began late in our third fiscal quarter for the year ended June 30, 2008, and accounted for 64% of total net production sold. Increased production was substantially offset by a 45% decline in the average price received per BOE, from $82 per BOE for year ended June 30, 2008 to $45 per BOE for the year ended June 30, 2009. Our properties in the Giddings Field generated

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almost 100% of our revenues for year ended June 30, 2009. Oil revenues from our properties in the Tullos Field, which were sold in March 2008, accounted for 35% of total revenues for the year ended June 30, 2008.

Lease Operating Expenses (including production severance taxes). Lease operating expenses and production taxes for the year ended June 30, 2009 increased approximately 7% from the year ended June 30, 2008. The increase is primarily attributable to a an increase in production taxes in the Giddings Field as compared to the Tullos Field, which accounted for 35% of our production during the previous fiscal year. The higher production taxes are due to higher revenues in our Texas properties compared to our production from our Louisiana properties in the previous fiscal year, even after adjusting for the Texas limited severance tax holiday on wells restored to production. Lease operating costs increased 2% from the prior fiscal year, primarily due to increased production in the Giddings Field. On a BOE basis, lease operating expenses (including production severance taxes) decreased by 58% over the prior fiscal year, due to increased production from our properties in the Giddings Field, which accounted for almost 100% of total production for the fiscal year ended June 30, 2009, but approximately 64% of production in the prior fiscal year. Our properties in the Tullos Field, which were sold in the third quarter of the prior fiscal year and accounted for 35% of total production for that year, consisted of numerous lower producing wells as compared to our properties in the Giddings Field, which consist of fewer higher producing wells.

General and Administrative Expenses (G&A). G&A expenses increased 7% to $5.9 million for the year ended June 30, 2009, compared to $5.5 million for the year ended June 30, 2008. Personnel costs decreased $0.6 million from the prior fiscal year, offset by an increases in non-cash stock-based compensation expense, which was $2,405,900 (41% of total G&A) and $1,791,486 (33% of total G&A) for the years ended June 30, 2009 and 2008, respectively. Also contributing to the increase were professional fees associated with the Delhi litigation of approximately $0.4 million for the year ended June 30, 2009. Non-cash stock-based compensation is an integral part of total staff compensation utilized to recruit quality staff from other, more established companies and, as a result, will likely continue to be a significant component of our G&A costs.

Depreciation, Depletion & Amortization Expense (DD&A). DD&A increased by $1,557,948 to $2,461,162 for the year ended June 30, 2009, compared to $903,214 for the year ended June 30, 2008. The increase is primarily due to a 160% increase in sales volumes from the prior fiscal year, and a higher depletion rate ($18.07 vs. $16.44) per BOE. The increase in the depletion rate is due to the higher development cost of PUDs locations in the Giddings Field that we added in amount far in excess of the volume of lower cost PDP production from our properties in the Tullos Field, which we sold in March 2008. Proved reserves in the Giddings Field typically are higher cost, but higher valued, compared to the long life, high operating cost proved reserves in the Tullos Field.

Interest Income. Interest income for the year ended June 30, 2009 decreased $731,858 to $122,272, compared to $854,130 for the year ended June 30, 2008. The decrease in interest income is due to lower available cash balances averaging $8.7 million during the year ended June 30, 2009, as compared to cash balances averaging $19.5 million during the year ended June 30, 2008, combined with a lower interest rate environment during the year ended June 30, 2009. The lower cash balance is primarily due to cash used for additions to our oil and natural gas properties.

Inflation. Although the general inflation rate in the United States, as measured by the Consumer Price Index and the Producer Price Index, has been relatively low in recent years, the oil and gas industry has experienced unusually volatile price movements. With the general rise in the price of oil and natural gas products over two of the last three fiscal years, increased prices for drilling and oilfield services, oilfield equipment, tubulars, labor, expertise and other services, have also increased, thereby escalating our lease operating expenses and our capital expenditures. Most recently, we have seen a precipitous decline in both petroleum product prices and drilling and oilfield services costs, although product prices, operating costs and development costs may not always move in tandem. Such declines as of June 30, 2009 are reflected in our ceiling test calculations.

Known Trends and Uncertainties. General worldwide economic conditions have deteriorated due to credit conditions impacted by the sub-prime mortgage turmoil and other factors. Concerns over slower or declining economic growth are affecting numerous industries, companies, as well as consumers, which has resulted in reduced demand for crude oil and natural gas. If demand continues to decrease in the future, it may continue to put downward pressure on crude oil and natural gas prices, thereby lowering our revenues and working capital going forward.

Seasonality. Our business is generally not seasonal, except for certain rare instances when weather conditions may adversely affect access to our properties or delivery of our petroleum products. Although we do not generally modify our production for changes in market demand, we do experience seasonality in the product prices we receive, generally based on higher demand for natural gas in the summer and winter and higher demand for downstream oil products during the summer driving season.

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Critical Accounting Policies and Estimates

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

Oil and Natural Gas Properties. Companies engaged in the production of oil and natural gas are required to follow accounting rules that are unique to the oil and gas industry. We apply the full-cost accounting method for our oil and natural gas properties. Another acceptable method of accounting for oil and natural gas production activities is the successful efforts accounting method. In general, the primary differences between the two methods are related to the capitalization of costs and the evaluation for asset impairment. Under full-cost accounting, all geological and geophysical costs, exploratory dry holes and delay rentals are capitalized to the full cost pool, whereas under the successful efforts accounting method such costs are expensed as incurred. In the assessment of impairment of oil and natural gas properties, the successful efforts accounting method follows the guidance of SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, under which the net book value of assets are measured for impairment against the undiscounted future cash flows using commodity prices consistent with management expectations. Under the full-cost accounting method, the full-cost pool is measured against future net cash flows discounted at 10% using commodity prices in effect at the end of the reporting period. The financial results for a given period could be substantially different depending on the method of accounting that a company adopts.

Proved Reserves, DD&A, and the Ceiling Test. Under full-cost accounting, the estimated quantities of proved oil and natural gas reserves have a significant impact on the underlying financial statements. The estimated quantities of proved reserves are used to calculate DD&A and the estimated future net cash flows associated with those proved reserves is the basis in determining impairment under the quarterly ceiling test calculation. The process of estimating oil and natural gas reserves is very complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering and economic data. Estimated reserves are often subject to future revisions, which could be substantial, based on the availability of additional information, including reservoir performance, additional development activity, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that the reported reserve estimates represent the most accurate assessments possible, including the hiring of independent engineers to prepare the report, the subjective decisions and variances in available data for the properties make these estimates generally less precise than other estimates included in our financial statements.

Material revisions to reserve estimates and or significant changes in commodity prices could substantially affect our estimated future net cash flows of our proved reserves, affecting our quarterly ceiling test calculation and could significantly affect our DD&A rate. A 10% decrease in commodity prices as of June 30, 2009, would not have resulted in an impairment of our oil and natural gas properties. A 10% decrease in our proved reserve quantities would have increased our DD&A by approximately $50 thousand for the year ended June 30, 2009 and would increase our DD&A rate by $1.87 per BOE.

On December 31, 2008, the SEC released new Modernization requirements for reporting oil and gas reserves. The Modernization disclosure requirements, when effective, provide for consideration of new technologies in evaluating reserves, allows companies to disclose their probable and possible reserves to investors, requires reporting of oil and gas reserves using an average price based on the prior 12-month period rather than year-end prices, revises the disclosure requirements for oil and gas operations, and revises accounting for the limitation on capitalized costs for full-cost companies. The Modernization disclosure requirements will become effective for our Annual Report on Form 10-K for the year ended June 30, 2010. The SEC is coordinating with the FASB to obtain the revisions necessary to provide consistency with the Modernization. In the event that consistency is not achieved in time for companies to comply with the Modernization, the SEC will consider delaying the compliance date. A significant change as a result of the Modernization requirements relates to the calculation of reserves. Under the Modernization requirements, reserves will be calculated on an average price which will reduce the volatility of the reserve estimate.

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Unproved Properties. On a quarterly basis, the costs of unproved properties are evaluated for inclusion in full cost pool due to the determination of proved reserves or impairment of the property. To the extent that the evaluation indicates these properties are impaired, the amount of the impairment is added to the full cost pool, which is amortized using the unit-of-production method, with no losses recognized.

Valuation of Deferred Tax Assets. We make certain estimates and judgments in determining our income tax expense for financial reporting purposes. These estimates and judgments occur in the calculation of certain tax assets and liabilities that arise from differences in the timing and recognition of revenue and expense for tax and financial reporting purposes. Our federal and state income tax returns are generally not prepared or filed before the consolidated financial statements are prepared or filed; therefore, we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits, and net operating loss carry backs and carry forwards. Adjustments related to these estimates are recorded in our tax provision in the period in which we file our income tax returns. Further, we must assess the likelihood that we will be able to recover or utilize our deferred tax assets (primarily our net operating loss). If recovery is not likely, we must record a valuation allowance against such deferred tax assets for the amount we would not expect to recover, which would result in an increase to our income tax expense. As of June 30, 2009, we have recorded a valuation allowance for the portion of our net operating loss that is limited by IRS Section 382.

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

Stock-based Compensation. We estimate the fair value of stock option awards on the date of grant using the Black-Scholes option pricing model. This valuation method requires the input of certain assumptions, including expected stock price volatility, expected term of the award, the expected risk-free interest rate, and the expected dividend yield of the Company s stock . The risk-free interest rates used is the U.S. Treasury yield for bonds matching the expected term of the option on the date of grant. Our dividend yield is zero, as we do not pay a dividend. Because of our limited trading experience of our common stock and limited exercise history of our stock option awards, estimating the volatility and expected term is very subjective. We base our estimate of our expected future volatility, on peer companies whose common stock has been trading longer than ours, along with our own limited trading history while operating as an oil and natural gas producer. Future estimates of our stock volatility could be substantially different from our current estimate, which could significantly affect the amount of expense we recognize for our stock-based compensation awards.

Off Balance Sheet Arrangements

The Company has no off-balance sheet arrangements as of June 30, 2009.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISKS

Interest Rate Risk

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

Commodity Price Risk

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

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Item 8. Financial Statements

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders

Evolution Petroleum Corporation

Houston, Texas

We have audited the accompanying consolidated balance sheets of Evolution Petroleum Corporation as of June 30, 2009 and 2008 and the related consolidated statements of operations, stockholders equity, and cash flows for each of two years in the period ended June 30, 2009. These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Evolution Petroleum Corporation as of June 30, 2009 and 2008, and the consolidated results of its operations and its cash flows for each of the two years in the period ended June 30, 2009 in conformity with accounting principles generally accepted in the United States of America.

We were not engaged to examine management s assertion about the effectiveness of Evolution Petroleum Corporation s internal controls over financial reporting as of June 30, 2009 included in the accompanying Management s Report on Internal Control over Financial Reporting and, accordingly, we do not express an opinion thereon.

HEIN & ASSOCIATES LLP

Houston, Texas

September 23, 2009

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PART I FINANCIAL INFORMATION

ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

Evolution Petroleum Corporation and Subsidiaries

Consolidated Balance Sheets

	June 30, 2009	June 30, 2008
Assets		
Current assets		
Cash and cash equivalents	$ 3,891,764	$ 11,272,280
Certificates of deposit	2,059,147	
Receivables		
Oil and natural gas sales	532,318	2,066,300
Income taxes		478,599
Other	172,314	86,966
Income taxes recoverable	2,055,802	3,625,987
Prepaid expenses and other current assets	162,441	270,938
Total current assets	8,873,786	17,801,070
Property and equipment, net of depreciation, depletion, and amortization		
Oil and natural gas properties full-cost method of accounting, of which $9,819,465 and $8,754,429 at June 30, 2009 and 2008, respectively, were excluded from amortization.	28,751,178	22,047,233
Other property and equipment	150,697	161,027
Total property and equipment	28,901,875	22,208,260
Other assets	53,162	356,518
Total assets	$ 37,828,823	$ 40,365,848
Liabilities and Stockholders Equity		
Current liabilities		
Accounts payable	$ 690,639	$ 2,892,459
Accrued payroll	71,427	772,559
Royalties payable	218,477	473,327
State taxes payable	157,736	
Other current liabilities	99,625	32,703
Total current liabilities	1,237,904	4,171,048
Long term liabilities		
Deferred income taxes	3,721,317	2,901,929
Asset retirement obligations	664,710	215,056
Stock bonus (Note 16)	370,440	
Deferred rent	77,858	74,081
Total liabilities	6,072,229	7,362,114

Commitments and contingencies (Note 13)				
Stockholders equity				
Preferred stock, par value $0.001; 5,000,000 shares authorized; no shares issued or outstanding				
Common stock; par value $0.001; 100,000,000 shares authorized; issued 27,318,517 shares; outstanding 26,530,317 shares and 26,870,439 shares as of June 30, 2009 and 2008, respectively.		27,318		26,870
Additional paid-in capital		16,424,868		14,188,841
Retained earnings		16,186,430		18,788,023
		32,638,616		33,003,734
Treasury stock, at cost, 788,200 shares as of June 30, 2009.		(882,022)		
Total stockholders equity		31,756,594		33,003,734
Total liabilities and stockholders equity	$	37,828,823	$	40,365,848

See accompanying notes to consolidated financial statements.

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Evolution Petroleum Corporation and Subsidiaries

Consolidated Statements of Operations

	Year Ended June 30, 2009	Year Ended June 30, 2008
Revenues		
Crude oil	$ 2,747,494	$ 2,918,127
Natural gas liquids	1,625,063	670,434
Natural gas	1,722,626	667,567
Total revenues	6,095,183	4,256,128
Operating Costs		
Lease operating expenses	1,281,989	1,255,787
Production taxes	158,794	90,252
Depreciation, depletion and amortization	2,461,162	903,214
Accretion of asset retirement obligations	37,601	20,196
General and administrative expenses *	5,896,366	5,497,237
Total operating costs	9,835,912	7,766,686
Loss from operations	(3,740,729)	(3,510,558)
Other income		
Interest income	122,272	854,130
Net loss before income tax benefit	(3,618,457)	(2,656,428)
Income tax benefit	1,016,864	1,085,454
Net loss	$ (2,601,593)	$ (1,570,974)
Loss per common share		
Basic and Diluted	$ (0.10)	$ (0.06)
Weighted average number of common shares		
Basic and Diluted	26,366,677	26,786,270

*General and administrative expenses for the year ended June 30, 2009 and 2008 included non-cash stock-based compensation expense of $2,405,900 and $1,791,486, respectively.

See accompanying notes to consolidated financial statements.

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Evolution Petroleum Corporation and Subsidiaries

Consolidated Statements of Cash Flow

	Year Ended June 30,