

**UNITED STATES  
SECURITIES AND EXCHANGE COMMISSION**

Washington, D.C. 20549

**FORM 10-K**

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

For the fiscal year ended June 30, 2009

**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**

(State or other jurisdiction of incorporation or organization)

**41-1781991**

(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:

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:

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

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

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

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

Large accelerated filer

Accelerated filer

Non-accelerated filer

Smaller reporting company

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

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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*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<sub>2</sub>.” 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](http://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<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub>-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<sub>2</sub> reserves approximately 100 miles east of the Delhi Field. We base our belief on (i) our internal analyses of CO<sub>2</sub> 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<sub>2</sub>-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<sub>2</sub>-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<sub>2</sub> reserves and a \$100 million minimum future investment, subject to penalties for non-performance, in a CO<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub>-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<sub>2</sub>-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<sub>2</sub>-EOR operator on the Gulf Coast, currently operating a large number of CO<sub>2</sub>-EOR projects and owns naturally occurring CO<sub>2</sub> 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<sub>2</sub>-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.

Customer	Year Ended June 30,		
	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<sub>2</sub>-EOR project in the Delhi Field, operated by Denbury Resources Inc., requires significant amounts of CO<sub>2</sub> reserves, the source of which may become unavailable or be curtailed. The Operator controls the operations and CO<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub>-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 and 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

	<u>Proved Developed Producing</u>	<u>Proved Developed Non-producing</u>	<u>Proved Undeveloped</u>	<u>Total Proved Reserves</u>
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)	<u>430,441</u>	<u>—</u>	<u>2,629,599</u>	<u>3,060,040</u>
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

	<u>Proved Developed Producing</u>	<u>Proved Developed Non-producing</u>	<u>Proved Undeveloped</u>	<u>Total Proved Reserves</u>
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)	<u>275,533</u>	<u>23,850</u>	<u>3,718,850</u>	<u>4,018,233</u>
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.

	<u>For the Years Ended June 30</u>	
	<u>2009</u>	<u>2008</u>
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	<u>\$ 23,549,791</u>	<u>\$ 97,072,641</u>

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[Table of Contents](#)**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:

Product	Year Ended June 30, 2009		Year Ended June 30, 2008		Year Ended June 30, 2007	
	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<sub>2</sub> and Mengel Units. With respect to the Delhi Holt Bryant Unit, currently scheduled for CO<sub>2</sub>-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<sub>2</sub>-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 (NYSE) 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	<u>5,833,878</u>	<u>\$ 1.81</u>	<u>1,006,461</u>

(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

[Table of Contents](#)**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
<b>Income Statement Data</b>					
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)
<b>Cash Flows Data</b>					
<b>Operating Activities:</b>					
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
<i>Cash provided by (used in) operating activities</i>	5,954,778	(856,800)	(14,492,048)	(737,204)	(1,077,535)
<b>Investing Activities:</b>					
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)
<i>Cash provided by (used in) investing activities</i>	(12,457,225)	(15,617,938)	32,360,975	11,822,625	(2,778,623)
<b>Financing Activities:</b>					
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	—	—	—	—
<i>Cash provided by (used in) financing activities</i>	(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
	<b>June 30, 2009</b>	<b>June 30, 2008</b>	<b>June 30, 2007</b>	<b>June 30, 2006 (as restated)</b>	<b>June 30, 2005</b>
<b>Balance Sheet Data</b>					
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
<b>Total operating revenues</b>		<b>983,951</b>		<b>1,164,464</b>		<b>1,031,782</b>		<b>2,914,986</b>		<b>2,356,504</b>
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
<b>Total operating expense</b>		<b>2,137,040</b>		<b>2,653,289</b>		<b>2,508,224</b>		<b>2,537,359</b>		<b>2,297,043</b>
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
<b>Net income (loss) before income taxes</b>	<b>\$</b>	<b>(1,130,269)</b>	<b>\$</b>	<b>(1,480,801)</b>	<b>\$</b>	<b>(1,458,660)</b>	<b>\$</b>	<b>451,273</b>	<b>\$</b>	<b>140,756</b>

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
<b>Total (BOE)</b>		<b>347.7</b>		<b>469.2</b>		<b>278.4</b>		<b>370.5</b>		<b>297.7</b>

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
<b>Total per BOE</b>		<b>31.10</b>		<b>27.27</b>		<b>40.29</b>		<b>85.51</b>		<b>86.98</b>

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
<b>Total operating expense</b>		<b>67.55</b>		<b>62.14</b>		<b>97.94</b>		<b>74.43</b>		<b>84.78</b>
Operating (loss) income	\$	(36.45)	\$	(34.87)	\$	(57.65)	\$	(11.08)	\$	2.20
<b>Net income (loss) before income taxes</b>	<b>\$</b>	<b>(35.72)</b>	<b>\$</b>	<b>(34.68)</b>	<b>\$</b>	<b>(56.96)</b>	<b>\$</b>	<b>(13.24)</b>	<b>\$</b>	<b>5.20</b>

(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<sub>2</sub> enhanced oil recovery technology and a dedicated portion of the Operator's proved CO<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub>-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.

- **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<sub>2</sub> 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		Variance	% change
	2009	2008		
<b>Sales Volumes, net to the Company:</b>				
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%
<b>Revenue data:</b>				
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%
<b>Average price:</b>				
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)%
<b>Expenses (per BOE)</b>				
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 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 increase 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
<b>Assets</b>		
<b>Current assets</b>		
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	<u>8,873,786</u>	<u>17,801,070</u>
<b>Property and equipment, net of depreciation, depletion, and amortization</b>		
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	<u>28,901,875</u>	<u>22,208,260</u>
Other assets	53,162	356,518
Total assets	<u>\$ 37,828,823</u>	<u>\$ 40,365,848</u>
<b>Liabilities and Stockholders' Equity</b>		
<b>Current liabilities</b>		
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	<u>1,237,904</u>	<u>4,171,048</u>
<b>Long term liabilities</b>		
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	<u>6,072,229</u>	<u>7,362,114</u>
<b>Commitments and contingencies (Note 13)</b>		
<b>Stockholders' equity</b>		
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	<u>31,756,594</u>	<u>33,003,734</u>
Total liabilities and stockholders' equity	<u>\$ 37,828,823</u>	<u>\$ 40,365,848</u>

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	2008
<b>Revenues</b>		
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	<u>6,095,183</u>	<u>4,256,128</u>
<b>Operating Costs</b>		
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	<u>9,835,912</u>	<u>7,766,686</u>
Loss from operations	(3,740,729)	(3,510,558)
<b>Other income</b>		
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	<u>\$ (2,601,593)</u>	<u>\$ (1,570,974)</u>
<b>Loss per common share</b>		
Basic and Diluted	<u>\$ (0.10)</u>	<u>\$ (0.06)</u>
<b>Weighted average number of common shares</b>		
Basic and Diluted	<u>26,366,677</u>	<u>26,786,270</u>

\*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,	
	2009	2008
<b>Cash flows from operating activities</b>		
Net loss	\$ (2,601,593)	\$ (1,570,974)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	2,461,162	903,214
Stock-based compensation	2,405,900	1,791,486
Issuance of common stock for charitable donation	28,600	—
Accretion of asset retirement obligations	37,601	20,196
Settlement of asset retirement obligations	(90,761)	—
Deferred income taxes	819,388	2,563,928
Deferred rent	3,777	26,792
Other assets	6,236	6,236
Changes in operating assets and liabilities:		
Receivables from oil and natural gas sales	1,533,982	(1,876,090)
Receivables from income taxes and other	1,963,436	(3,747,852)
Prepaid expenses and other current assets	108,497	90,902
Accounts payable and accrued expenses	(624,333)	468,866
Royalties payable	(254,850)	466,496
Income taxes payable	157,736	—
Net cash provided by (used in) operating activities	<u>5,954,778</u>	<u>(856,800)</u>
<b>Cash flows from investing activities</b>		
Net proceeds from the sale of the Tullos Assets	—	4,420,868
Proceeds from other asset sales	—	31,582
Development of oil and natural gas properties	(8,063,465)	(11,187,291)
Acquisitions of oil and natural gas properties	(2,603,098)	(8,789,501)
Capital expenditures for other equipment	(28,635)	(87,544)
Purchases of certificates of deposit	(1,757,312)	—
Other assets	(4,715)	(6,052)
Net cash used in investing activities	<u>(12,457,225)</u>	<u>(15,617,938)</u>

Cash flows from financing activities		
Proceeds from issuance of restricted stock	130	76
Purchase of treasury stock	(882,022)	—
Other	3,823	—
Net cash (used in) provided by financing activities	(878,069)	76
Net decrease in cash and cash equivalents	(7,380,516)	(16,474,662)
Cash and cash equivalents, beginning of period	11,272,280	27,746,942
Cash and cash equivalents, end of period	<u>\$ 3,891,764</u>	<u>\$ 11,272,280</u>

See accompanying notes to consolidated financial statements.

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**Evolution Petroleum Corporation and Subsidiaries**  
**Consolidated Statements of Changes in Stockholders' Equity**

	Common Stock		Additional Paid-in Capital	Retained Earnings	Treasury Stock	Total Stockholders' Equity
	Shares	Par Value				
Balance, July 1, 2007	26,776,234	\$ 26,776	\$ 12,397,373	\$ 20,358,997	\$ —	\$ 32,783,146
Issuance of restricted common stock	75,899	76	—	—	—	76
Exercise of warrants	8,306	8	(8)	—	—	—
Exercise of stock options	10,000	10	(10)	—	—	—
Stock-based compensation	—	—	1,791,486	—	—	1,791,486
Net loss	—	—	—	(1,570,974)	—	(1,570,974)
Balance, June 30, 2008	26,870,439	\$ 26,870	\$ 14,188,841	\$ 18,788,023	\$ —	\$ 33,003,734
Issuance of common stock to certain employees in lieu of partial payment of 2008 cash bonus	46,795	47	168,415	—	—	168,462
Issuance of restricted common stock	390,283	390	(260)	—	—	130
Issuance of common stock for charitable donation	11,000	11	28,589	—	—	28,600
Purchase of 788,200 treasury shares	(788,200)	—	—	—	(882,022)	(882,022)
Other	—	—	3,823	—	—	3,823
Stock-based compensation	—	—	2,035,460	—	—	2,035,460
Net loss	—	—	—	(2,601,593)	—	(2,601,593)
Balance, June 30, 2009	26,530,317	\$ 27,318	\$ 16,424,868	\$ 16,186,430	\$ (882,022)	\$ 31,756,594

See accompanying notes to consolidated financial statements.

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**EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES**  
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

**Note 1 — Organization and Basis of Preparation**

**Nature of Operations.** Evolution Petroleum Corporation (“EPM”) and its subsidiaries (the “Company”, “we”, “our” or “us”), is an independent petroleum company headquartered in Houston, Texas and incorporated under the laws of the State of Nevada. We are engaged primarily in the acquisition, exploitation and development of properties for the production of crude oil and natural gas. We acquire properties with known oil and natural gas resources and exploit them through the application of conventional and specialized technology to increase production, ultimate recoveries, or both.

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

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

**Note 2 — Summary of Significant Accounting Policies**

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

**Allowance for Doubtful Accounts.** We establish provisions for losses on accounts receivables if it is determined that collection of all or a part of an outstanding balance is not probable. Collectibility is reviewed regularly and an allowance is established or adjusted, as necessary, using the specific identification method. As of June 30, 2009 and 2008, no allowance for doubtful accounts was considered necessary.

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

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

**Limitation on Capitalized Costs.** Under the full-cost method of accounting, we are required, at the end of each fiscal quarter, to perform a test to determine the limit on the book value of our oil and natural gas properties (the "Ceiling Test"). If the capitalized cost of our oil and natural gas properties, net of accumulated amortization and related deferred income taxes (the "Net Capitalized Costs"), exceed the "Ceiling", this excess or impairment is charged to expense and reflected as additional accumulated depreciation, depletion and amortization or as a credit to oil and natural gas properties. The expense may not be reversed in future periods, even though higher oil and natural gas prices may subsequently increase the Ceiling. The Ceiling is defined as the sum of: (a) the present value, discounted at 10 percent, and assuming continuation of existing economic

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**EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES  
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

**Note 2 — Summary of Significant Accounting Policies (Continued)**

conditions, of 1) estimated future gross revenues from proved reserves, which is computed using oil and natural gas prices in effect at the balance sheet date (with consideration of price changes only to the extent provided by contractual arrangements including hedging arrangements pursuant to SAB 103), less 2) estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves; plus (b) the cost of properties not being amortized (pursuant to Reg. S-X Rule 4-10 (c)(3)(ii)); plus (c) the lower of cost or estimated fair value of unproven properties included in the costs being amortized; net of (d) the related tax effects related to the difference between the book and tax basis of our oil and natural gas properties. Our Ceiling Test did not result in an impairment of our oil and natural gas properties during the years ended June 30, 2009 and 2008.

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

**Asset Retirement Obligations.** Our investment in oil and natural gas properties includes an estimate of the future cost associated with dismantlement, abandonment and restoration of our properties. These costs are recorded as provided in Statement of Financial Accounting Standards ("SFAS") No. 143, *Accounting for Asset Retirement Obligations*. The present value of the future costs (the "asset retirement cost") is added to the capitalized cost of our oil and natural gas properties and recorded as a long-term or current liability. The asset retirement cost is depleted over the life of our oil and natural gas properties. The estimation of future costs associated with dismantlement, abandonment and restoration requires the use of estimated costs in future periods that, in some cases, will not be incurred until a substantial number of years in the future. Such cost estimates could be subject to significant revisions in subsequent years due to changes in regulatory requirements, technological advances and other factors which may be difficult to predict.

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

**Stock-based Compensation.** Effective July 1, 2006, we adopted SFAS No. 123(R), *Share-Based Payment* ("SFAS No. 123(R)"), using the modified prospective transition method which requires, among other things, current recognition of compensation expense for share-based compensation granted after July 1, 2006, and for that portion of prior period share-based compensation for which the requisite service had not been rendered as of July 1, 2006. SFAS No. 123(R) requires that we record all share-based payment expense in our financial statements based on the fair value of the award on the grant date. We use the Black-Scholes option-pricing model as the most appropriate fair-value method for our awards and recognize compensation cost on a straight-line basis over our awards' vesting periods.

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

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

**Income Taxes.** We account for income taxes in accordance with SFAS No. 109, *Accounting for Income Taxes* ("SFAS No. 109") and, as of July 1, 2007, the Financial Accounting Standards Board ("FASB") Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* ("FIN 48"). We recognize deferred tax

assets and liabilities based on the differences between the tax basis of assets and liabilities and their reported amounts in the financial statements that may result in taxable or deductible amounts in future years. The measurement of deferred tax assets may be reduced by a valuation allowance based upon management's assessment of available evidence if it is deemed more likely than not some or all of the deferred tax assets will not be realizable.

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**EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES**  
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

**Note 2 — Summary of Significant Accounting Policies (Continued)**

FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with SFAS No. 109. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. We recognize estimated interest and penalties related to any potential underpayment on unrecognized tax benefits as a component of income tax expense in the Consolidated Statement of Operations.

**Earnings (loss) per share.** Earnings (loss) per share ("EPS") of common Stock is computed in accordance with SFAS No. 128 *Earnings per Share* ("SFAS No. 128"). Under the provisions of SFAS No. 128, basic EPS is computed by dividing earnings or loss by the weighted-average number of common shares outstanding less any non-vested restricted common stock outstanding. The computation of diluted EPS is similar to the computation of basic EPS, except that the denominator is increased to include the number of additional common shares that would have been outstanding if potential dilutive common shares had been issued. Our potential dilutive common shares are our outstanding stock options, warrants, and non-vested restricted common stock. The dilutive effect of our potential dilutive common shares is reflected in diluted EPS by application of the treasury stock method. Under the treasury stock method, exercise of stock options and warrants shall be assumed at the beginning of the period (or at time of issuance, if later) and common shares shall be assumed to be issued; the proceeds from exercise shall be assumed to be used to purchase common stock at the average market price during the period; and the incremental shares (the difference between the number of shares assumed issued and the number of shares assumed purchased) shall be included in the denominator of the diluted EPS computation. Potential dilutive common shares are excluded from the computation if their effect is anti-dilutive. Including potential dilutive common shares in the denominator of a diluted EPS computation for continuing operations always will result in an anti-dilutive per-share amount when an entity has a loss from continuing operations and no potential dilutive common shares shall be included in the computation of diluted EPS when a loss from continuing operations exists.

**Note 3 — Recent Accounting Pronouncements**

**New Accounting Standards.** The following discloses the existence and effect of accounting standards issued but not yet adopted by us with respect to accounting standards that may have an impact on the Company when adopted in the future.

**Consolidation rules as they relate to variable interest entities.** In June 2009, the FASB issued SFAS No. 167, *Amendments to FASB Interpretation No. 46(R)* ("SFAS No. 167"), which amends the consolidation guidance applicable to variable interest entities. The amendments significantly reduce the previously required quantitative consolidation analysis, and require ongoing reassessments of whether the Company is the primary beneficiary of a variable interest entity. SFAS No. 167 also requires enhanced disclosures about an enterprise's involvement with a variable interest entity. This statement is effective for the beginning of the first annual reporting period beginning after November 15, 2009. The Company is currently evaluating the impact, if any, of the adoption of SFAS No. 167 on its consolidated financial statements.

**Modernization of Oil and Gas Reporting.** On December 31, 2008, the SEC released new requirements for reporting oil and gas reserves. The new 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 new rule is expected to be effective for fiscal years ending on or after December 31, 2009, although the transition may be extended. A company may not apply the new rules to disclosures in quarterly reports prior to the first annual report in which the revised disclosures are required. We have not yet evaluated the effects the new rule will have on our financial statements.

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**EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES**  
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

**Note 3 — Recent Accounting Pronouncements (Continued)**

**Accounting for Earnings Per Share.** In June 2008, the FASB issued Staff Position No. EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities* ("FSP No. EITF 03-6-1"). FSP No. EITF 03-6-1 addresses whether instruments granted in share-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the earnings allocation in computing earnings per share under the two-class method described in FASB Statement No. 128, *Earnings Per Share*. FSP No. EITF 03-6-1 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2008; early adoption is not permitted. The adoption of FSP No. EITF 03-6-1 will be effective for us for interim and annual periods ending after July 1, 2009. We are currently evaluating what the impact, if any, of FSP No. EITF 03-6-1 will have on our earnings per share.

**Accounting for Business Combinations.** In December 2007, the FASB issued SFAS No. 141R, *Business Combinations* ("SFAS No. 141R"), which replaces SFAS No. 141, *Business Combinations*. SFAS No. 141R establishes principles and requirements for determining how an enterprise recognizes and measures the fair value of certain assets and liabilities acquired in a business combination, including non-controlling interests, contingent consideration, and certain acquired contingencies. SFAS No. 141R also requires acquisition-related transaction expenses and restructuring costs be expensed as incurred rather than

capitalized as a component of the business combination. SFAS No. 141R will be applicable prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. SFAS No. 141R would have an impact on accounting for any businesses acquired after the effective date of this pronouncement.

#### Note 4 — Sale of Oil and Natural Gas Properties

On March 3, 2008, NGS Sub Corp., a Delaware corporation wholly owned by EPM (“NGS Sub”), pursuant to an Asset Purchase and Sale Agreement (the “Asset Sale Agreement”) dated February 15, 2008, completed the sale of its 100% working interest and approximately 79% average net revenue interest in producing and shut-in crude oil wells, water disposal wells, equipment and improvements (the “Tullos Assets”) located in the Tullos Urania, Colgrade and Crossroads Fields in LaSalle and Winn Parishes, Louisiana (the “Tullos Field”). The following table presents the transaction and its affect on our financial statements.

<b>Proceeds from sale of properties in the Tullos Field</b>	\$ 4,649,241
Less payout of a third party carried interest arrangement	(168,106)
Less miscellaneous transaction costs	(60,267)
<i>Net proceeds</i>	4,420,868
<b>Net book value of our properties in the Tullos Field on March 3, 2008</b>	
Asset retirement obligation	153,886
Oil and natural gas properties	(1,721,990)
Other property and equipment	(26,721)
Prepaid expenses and other current assets	(178,826)
Other assets	(13,347)
<b>Remaining credit recorded to oil and natural gas properties</b>	<u>\$ 2,633,870</u>

The following unaudited pro forma consolidated financial information is presented for illustrative purposes only and presents the pro forma operating results for the Company for the year ended June 30, 2008 as though the disposition of our properties in the Tullos Field occurred on July 1, 2007. The unaudited pro forma consolidated financial information is not intended to be indicative of the operating results that actually would have occurred if the transaction had been consummated at the beginning of the period presented, nor is the information intended to be indicative of future operating results.

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### EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

#### Note 4 — Sale of Oil and Natural Gas Properties (Continued)

The unaudited pro forma consolidated financial information for the year ended June 30, 2008 is as follows:

	Year Ended June 30, 2008	
	As Reported	Pro Forma
Oil and natural gas revenues	\$ 4,256,128	\$ 2,778,773
Loss from operations	(3,510,558)	(3,740,623)
Net loss	(1,570,974)	(1,705,917)
Loss per common share — basic and diluted	\$ (.06)	\$ (.07)

#### Note 5 — Property and Equipment

As of June 30, 2009 and June 30, 2008 our oil and natural gas properties and other property and equipment consisted of the following:

	June 30, 2009	June 30, 2008
<b>Oil and natural gas properties</b>		
Property costs subject to amortization	\$ 21,985,950	\$ 13,924,844
Less: Accumulated depreciation, depletion, and amortization	(3,054,237)	(632,040)
Unproved properties not subject to amortization	9,819,465	8,754,429
Oil and natural gas properties, net	<u>\$ 28,751,178</u>	<u>\$ 22,047,233</u>
<b>Other property and equipment</b>		
Furniture, fixtures and office equipment, at cost	260,476	231,841
Less: Accumulated depreciation	(109,779)	(70,814)
Other property and equipment, net	<u>\$ 150,697</u>	<u>\$ 161,027</u>

Unproved properties not subject to amortization include unevaluated acreage of \$7.5 and \$6.8 million as of June 30, 2009 and June 30, 2008, respectively. As of June 30, 2009, this acreage consists of properties in the Giddings Field, our projects in the Woodford Shale trend in Oklahoma, and our Neptune oil project in South Texas. As of June 30, 2008, the unevaluated acreage consisted of properties in the Giddings Field and our projects in the Woodford Shale trend in Oklahoma. Unproved properties also include \$2.0 million as of June 30, 2009 and June 30, 2008 of participating interests through royalty and overriding royalty interests aggregating 7.4% of the Delhi Holt Bryant Unit in the Delhi Field in Louisiana. We incurred \$0.3 million during the year ended June 30, 2009 to initiate 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. Subject to industry conditions, evaluation of these properties is expected to be completed within one to five years. Our evaluation of impairment of unproved properties occurs, at a minimum, on a quarterly basis.



The following table provides a summary of costs that are not being amortized as of June 30, 2009, by the fiscal year in which the costs were incurred:

Costs excluded from amortization	Total	During the Year Ended June 30,			2006 and Prior
		2009	2008	2007	
Leasehold acquisition costs and other	\$ 7,515,685	\$ 1,410,305	\$ 5,278,419	\$ 826,961	\$ —
Royalty and overriding royalty interests	1,954,377	3,636	—	966,794	983,947
Test drilling	349,403	349,403	—	—	—
	<u>\$ 9,819,465</u>	<u>\$ 1,763,344</u>	<u>\$ 5,278,419</u>	<u>\$ 1,793,755</u>	<u>\$ 983,947</u>

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**EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES**  
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

**Note 6 — Asset Retirement Obligations**

Our asset retirement obligations represent the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties at the end of their productive lives in accordance with applicable laws. The following is a reconciliation of the beginning and ending asset retirement obligation for the years ended June 30, 2009 and 2008:

	Year Ended	
	2009	2008
<b>Asset retirement obligations — beginning of period</b>	\$ 215,056	\$ 140,998
Liabilities incurred	238,702	170,890
Liabilities settled	(90,761)	—
Liabilities sold (See Note 4)	—	(153,886)
Accretion	37,601	20,196
Revisions to previous estimates	264,112	36,858
<b>Asset retirement obligations — end of period</b>	<u>\$ 664,710</u>	<u>\$ 215,056</u>

**Note 7 — Stockholders' Equity**

During the year ended June 30, 2009, warrants to purchase 53,000 shares of common stock, with an exercise price of \$1.00 per share, expired unexercised. During the year ended June 30, 2008, 8,306 shares of common stock were issued through a net cashless exercise of warrants to purchase 14,463 shares.

We entered into a one-year consulting agreement in February 2008 for investor relations services. As compensation for services, we issued the consultant 50,000 shares of restricted common stock, which was subject to vesting, through December 2008. We did not renew this agreement for the year ended June 30, 2009.

On August 19, 2008, the Board of Directors authorized the issuance of 46,795 shares of common stock to certain employees who elected to receive these shares in lieu of a portion of their fiscal 2008 cash bonus. The value of the shares issued was \$168,462, based on the fair market value on the date of issuance, or \$3.60 per share. See Note 8.

On October 30, 2008, we repurchased 788,200 shares of our common stock at an average price of \$1.10 per share, plus approximately \$15,000 of transaction costs, from an unaffiliated accredited investor. At this time, we currently have no plan to repurchase additional common shares.

On December 9, 2008, three outside directors each received 30,000 shares of restricted common stock, with a per share price of \$1.20, as part of their board compensation for calendar 2009. The same outside directors each received 8,633 shares of restricted common stock, with a per share price of \$4.17, as part of their board compensation for calendar year 2008. All issuances of common stock were subject to vesting terms per individual stock agreements, which is generally one year for directors.

On January 16 and February 10, 2009, we issued 24,324 and 15,789 shares of restricted common stock, respectively, to a director as compensation for his services for calendar year 2009. The 15,789 share award was elected by the director in lieu of cash retainers for his board service during calendar 2009. These issuances of common stock are subject to vesting terms per the individual stock agreements, which is generally one year for directors.

On May 29, 2009, we issued 11,000 shares of unregistered common stock to various non-profit entities as a charitable donation. We recognized an expense of \$28,600 based on the per share price of \$2.60 on the date of issue. These shares of common stock are subject to restrictions on transfer and cannot be sold until registered or the earlier of April 17, 2014, or written release by a duly appointed officer of the Company.

On June 19, 2009, pursuant to an offer by the Company as discussed in Note 8, we issued 260,170 shares of restricted common stock to certain employees in exchange for stock options to purchase 449,390 shares of common stock with a weighted average exercise price of \$4.67.

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**EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES**  
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

**Note 8 — Stock-Based Incentive Plan**

We have granted option awards to purchase common stock (the "Stock Options") and restricted common stock awards ("Restricted Stock") to employees, directors, and consultants of the Company and its subsidiaries under the Natural Gas Systems Inc. 2003 Stock Plan (the "2003 Stock Plan") and the Evolution Petroleum Corporation Amended and Restated 2004 Stock Plan (the "2004 Stock Plan" or together, the "EPM Stock Plans"). Option awards for the purchase of 600,000 shares of common stock were issued under the 2003 Stock Plan. The 2004 Stock Plan authorized the issuance of 5,500,000 shares of common stock. There are no shares available for grant under the 2003 Stock Plan and, as of June 30, 2009, 1,006,461 shares remain available for grant under the 2004 Stock Plan.

We have also granted common stock warrants, as authorized by the Board of Directors, to employees in lieu of cash bonuses or as incentive awards to reward previous service or provide incentives to individuals to acquire a proprietary interest in the Company's success and to remain in the service of the Company (the "Incentive Warrants"). These Incentive Warrants have similar characteristics of the Stock Options. A total of 1,037,500 Incentive Warrants have been issued, with Board of Directors approval, outside of the EPM Stock Plans. We did not issue Incentive Warrants during the fiscal years ended June 30, 2009 and 2008.

On September 8, 2009, the Board of Directors authorized the issuance of 138,224 shares of common stock from the 2004 Stock Plan to certain employees for the payment of fiscal 2009 bonuses in lieu of cash. The value of the shares issued was \$370,440, based on the fair market value on the date of issuance, or \$2.68 per share. The amount of bonus was accrued as of June 30, 2009, and recognized as a long term liability. On September 8, 2009, the liability was reclassified as additional paid-in capital.

On August 19, 2008, the Board of Directors authorized the issuance of 46,795 shares of common stock from the 2004 Stock Plan to certain employees who elected to receive these shares in lieu of a portion of their fiscal 2008 cash bonus. The value of the shares issued was \$168,462, based on the fair market value on the date of issuance, or \$3.60 per share.

### ***Offer to Exchange***

The extreme financial market volatility encountered during fiscal 2009 caused us to reassess the continued effectiveness of our outstanding stock options granted to employees for the purposes of retention and equity participation. Based on management's analysis and considerable review, our Board of Directors approved an "exchange offer" to employees with "out-of-the-money" options, excluding Executive Officers and Directors. Under the terms of the offer, each eligible option to purchase 1.727 shares could be exchanged for one share of restricted common stock. In return, the company and shareholders benefited by (i) re-establishing the retention incentive for nonexecutive employees, (ii) adding one additional year of vesting to all awards exchanged, as further described below, (iii) reduced dilution as the number of restricted shares issued was substantially less than the options exchanged and the exchanged options were returned to the 2004 Plan, and (iv) spread the expense of the incentives over a longer period of time.

Accordingly, we filed a Tender Offer Statement on Schedule TO with the SEC on May 15, 2009, and amendments on May 21, 2009, June 9, 2009, and a final filing on July 2, 2009 announcing termination of the offer, relating to an offer by us to certain employees to exchange certain outstanding Stock Options granted under the 2004 Stock Plan, with shares of Restricted Stock (the "Offer to Exchange"). The Offer to Exchange expired on June 19, 2009 (the "Expiration Date"). Pursuant to the Offer to Exchange, 449,390 eligible Stock Options were tendered and subsequently cancelled, representing 54% of the total Stock Options that were eligible for exchange in the Offer to Exchange. The shares of common stock that were subject to the cancelled Stock Options will be available for future awards under our 2004 Stock Plan. On June 19, 2009 the Company granted an aggregate of 260,170 shares of Restricted Stock in exchange for the Stock Options surrendered in the Offer to Exchange.

Under SFAS No. 123 (Revised) *Share-Based Payment*, we will recognize the unrecognized compensation cost associated with the 449,390 Stock Options cancelled pursuant to the Offer to Exchange of approximately \$1,068,430 along with the incremental compensation cost of \$78,891 ratably over the vesting period of the Restricted Stock. The incremental compensation, determined on June 19, 2009, was measured as the excess of the fair value of the Restricted Stock granted in the Offer to Exchange, over the fair value of the Stock Options surrendered prior to cancellation. The price of our common stock as of June 19, 2009 was \$2.85, however, due to the requirements of SFAS No. 123 (Revised) *Share-Based Payment*, we will recognize expense ratably over the vesting period of the Restricted Stock granted in the Offer to Exchange of approximately \$4.41 per share.

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### **EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

#### **Note 8 — Stock-Based Incentive Plan (Continued)**

The shares of Restricted Stock granted in the Offer to Exchange were unvested at the time of grant and will become vested on the basis of continued service with the Company in accordance with and subject to the terms of the Offer to Exchange as follows: If and to the extent the Stock Options surrendered were vested on the Expiration Date, the Restricted Stock exchanged for those vested Stock Options will become vested on the first anniversary of the Expiration Date, being June 19, 2010. If and to the extent any Stock Options surrendered were not vested on the Expiration Date the Restricted Stock exchanged for those unvested Stock Options will become vested on the first anniversary of the original vesting dates on which such unvested Stock Options would have otherwise become vested. The Restricted Stock granted pursuant to the Offer to Exchange will vest over a weighted average period of approximately four years.

#### ***Stock Options and Incentive Warrants***

Non-cash stock-based compensation expense related to Stock Options and Incentive Warrants for the year ended June 30, 2009 and 2008 was \$1,786,055 and \$1,522,661, respectively.

During the year ended June 30, 2009 and 2008, we granted Stock Options to purchase 591,090 and 1,435,000 shares of common stock, respectively, under the 2004 Stock Plan with a weighted average exercise price of \$4.27 and \$2.58, respectively. The exercise price was determined based on the market price of the Company's common stock on the date of grant. The Stock Options granted during the years ended June 30, 2009 and 2008 generally vest quarterly, on a straight line basis, over a period of four years. The Stock Options granted during the year ended June 30, 2009 and 2008 have a contractual life of seven and

ten years, respectively. The weighted average assumptions used to calculate the fair value of these Stock Options and the weighted average fair value of each option granted are as follows:

	Year Ended June 30,	
	2009	2008
Expected volatility	87.1%	93.3%
Expected dividends	—	—
Expected term (in years)	4.6	6.1
Risk-free rate	3.10%	4.10%
Fair value	\$ 2.62	\$ 2.01

We estimated the fair value of Stock Options and Incentive Warrants issued to employees and directors under SFAS No. 123R at the date of grant using a Black-Scholes-Merton valuation model. The risk-free rate is based on the U.S. Treasury yield curve in effect at the time of grant. The expected term (estimated period of time outstanding) of Stock Options and Incentive Warrants is based on the “simplified” method of the estimated expected term for “plain vanilla” options allowed by the SEC Staff Accounting Bulletin (“SAB”) No. 107 and SAB No. 110, and varied based on the vesting period and contractual term of the Stock Options or Incentive Warrants. Expected volatility is based on the historical volatility of the Company’s closing common stock price and that of an evaluation of a peer group of similar companies trading activity. We have not declared any cash dividends on the Company’s common stock.

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**EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES**  
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

**Note 8 — Stock-Based Incentive Plan (Continued)**

The following summary presents information regarding outstanding Stock Options and Incentive Warrants as of June 30, 2009, and the changes during the fiscal year:

	Number of Stock Options and Incentive Warrants	Weighted Average Exercise Price	Aggregate Intrinsic Value (1)	Weighted Average Remaining Contractual Term (in years)
Stock Options and Incentive Warrants outstanding at July 1, 2008	5,483,500	\$ 1.81		
Granted	591,090	\$ 4.27		
Exercised	—	—		
Cancelled or forfeited	(139,380)	\$ 2.65		
Voluntary cancellation and forfeiture under the Offer to Exchange	(449,390)	\$ 4.53		
Expired	—	—		
Stock Options and Incentive Warrants outstanding at June 30, 2009	<u>5,485,820</u>	<u>\$ 1.83</u>	<u>\$ 4,789,050</u>	<u>6.4</u>
Vested or expected to vest at June 30, 2009	<u>5,485,820</u>	<u>\$ 1.83</u>	<u>\$ 4,789,050</u>	<u>6.4</u>
Exercisable at June 30, 2009	<u>4,393,908</u>	<u>\$ 1.63</u>	<u>\$ 4,441,131</u>	<u>6.1</u>

(1) Based upon the difference between the market price of our common stock on the last trading date of the period (\$2.60 as of June 30, 2009) and the Stock Option or Incentive Warrant exercise price of in-the-money Stock Options and Incentive Warrants.

There were no Stock Options or Incentive Warrants that were exercised during the year ended June 30, 2009. There were 10,000 Stock Options exercised during the year ended June 30, 2008 with an aggregate intrinsic value of \$58,790.

A summary of the status of our unvested Stock Options and Incentive Warrants as of June 30, 2009 and the changes during the year ended June 30, 2009, is presented below:

	Number of Stock Options and Incentive Warrants	Weighted Average Grant- Date Fair Value
Unvested at July 1, 2008	2,003,437	\$ 1.83
Granted	591,090	\$ 2.62
Vested	(1,063,029)	\$ 1.76
Forfeited	(93,207)	\$ 1.97

Voluntary forfeiture under the Offer to Exchange	(346,379)	\$ 3.08
Unvested at June 30, 2009	<u>1,091,912</u>	<u>\$ 1.97</u>

During the years ended June 30, 2009 and 2008, there were 1,063,029 and 1,004,688 Stock Options and Incentive Warrants that vested with a total grant date fair value of \$1,870,931 and \$1,577,360, respectively.

The total unrecognized compensation cost at June 30, 2009, relating to non-vested Stock Options and Incentive Warrants was \$2,059,852. Such unrecognized expense is expected to be recognized over a weighted average period of 2.3 years.

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**EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES  
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

**Note 8 — Stock-Based Incentive Plan (Continued)**

**Restricted Stock**

During the year ended June 30, 2009, we issued 130,113 shares of restricted common stock to certain members of our board of directors. For the year ended June 30, 2008, we issued 25,899 and 50,000 shares of restricted common stock to certain members of our board of directors and a consultant, respectively.

On June 19, 2009, we issued 260,170 shares of restricted common stock to certain employees pursuant to the Offer to Exchange as described above.

Stock-based compensation expense related to Restricted Stock grants for the three year ended June 30, 2009 and 2008 was \$249,405 and \$268,825, respectively.

The following table sets forth the Restricted Stock transactions for the year ended June 30, 2009:

	<u>Number of Restricted Shares</u>	<u>Weighted Average Grant-Date Fair Value</u>
Unvested at July 1, 2008	50,898	\$ 4.11
Granted	130,113	\$ 1.29
Granted under the Offer to Exchange	260,170	\$ 4.41
Vested	(50,898)	\$ 4.11
Forfeited	—	—
Unvested at June 30, 2009	<u>390,283</u>	<u>\$ 3.37</u>

At June 30, 2009, unrecognized stock compensation expense related to Restricted Stock grants totaled \$1,221,246. Such unrecognized expense will be recognized over a weighted average period of 3.7 years.

**Note 9 — Supplemental Disclosure of Cash Flow Information**

Our supplemental disclosures of cash flow information for the year ended June 30, 2009 and 2008 are as follows:

	<u>Year Ended June 30,</u>	
	<u>2009</u>	<u>2008</u>
Income taxes paid:	\$ 15,000	\$ 33,879
Income tax refunds and net operating loss carry-back received:	\$ 4,057,772	—
<b>Non-cash transactions:</b>		
Increase (decrease) in accounts payable used to acquire oil and natural gas leasehold interests and develop oil and natural gas properties:	\$ (2,043,235)	\$ 1,639,128
Oil and natural gas properties incurred through recognition of asset retirement obligations:	\$ 502,814	\$ 207,748
Common stock issued in lieu of a portion of 2008 cash bonus accrued at June 30, 2008:	\$ 168,462	\$ —

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**EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES  
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

## Note 10 — Income Taxes

We file a consolidated federal income tax return in the United States and various combined and separate filings in several state and local jurisdictions.

There were no unrecognized tax benefits nor any accrued interest or penalties associated with unrecognized tax benefits as of the date of adoption of FIN 48 and through June 30, 2009. We believe that we have appropriate support for the income tax positions taken and to be taken on the Company's tax returns and that the accruals for tax liabilities are adequate for all open years based on our assessment of many factors including past experience and interpretations of tax law applied to the facts of each matter. The Company's federal and state income tax returns are open to audit under the statute of limitations for the years ending June 30, 2006 through June 30, 2008.

The components of our income tax benefit are as follows:

	June 30, 2009	June 30, 2008
<b>Current:</b>		
Federal	\$ (1,993,988)	\$ (3,551,036)
State	157,736	(98,346)
<i>Total current income tax benefit</i>	<u>(1,836,252)</u>	<u>(3,649,382)</u>
<b>Deferred:</b>		
Federal	528,787	2,573,023
State	290,601	(9,095)
<i>Total deferred income tax provision</i>	<u>819,388</u>	<u>2,563,928</u>
<b>Total income tax benefit</b>	<u>\$ (1,016,864)</u>	<u>\$ (1,085,454)</u>

The following is a reconciliation of statutory income tax expense to our income tax provision:

	June 30, 2009	June 30, 2008
<b>Income tax benefit computed at the statutory federal rate:</b>	\$ (1,230,275)	\$ (929,750)
Reconciling items:		
State income taxes, net of federal tax benefit	148,134	(87,377)
Stock-based compensation (primarily incentive stock options)	264,060	425,236
Deferred tax asset valuation adjustment	(152,588)	(417,058)
Rate adjustment	21,931	—
IRC section 199 deduction	—	(69,771)
Other	(68,126)	(6,734)
<b>Income tax benefit</b>	<u>\$ (1,016,864)</u>	<u>\$ (1,085,454)</u>

Deferred income taxes primarily represent the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The components of our deferred taxes are detailed in the table below:

	June 30, 2009	June 30, 2008
<b>Deferred tax assets:</b>		
Non qualified stock-based compensation	\$ 657,369	\$ 274,836
Net operating loss carryforwards	5,389,065	5,547,567
Other	22,841	5,708
<i>Gross deferred tax assets</i>	<u>6,069,275</u>	<u>5,828,111</u>
Valuation allowance	(5,187,983)	(5,340,571)
<i>Total deferred tax assets</i>	<u>881,292</u>	<u>487,540</u>
<b>Deferred tax liability:</b>		
Oil and natural gas properties	(4,602,609)	(3,389,469)
<i>Total deferred tax liability</i>	<u>(4,602,609)</u>	<u>(3,389,469)</u>
<b>Net deferred tax liability</b>	<u>\$ (3,721,317)</u>	<u>\$ (2,901,929)</u>

## EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

### Note 10 — Income Taxes (Continued)

We expect to recover approximately \$2.1 million in federal income taxes paid during the tax year ended June 30, 2007, as a result of the carry-back of our 2009 income tax loss. Significant intangible drilling costs were incurred during the 2009 fiscal year, of which, we elected to deduct (expense) approximately \$4.8 million for federal and state income tax purposes. During the year ended June 30, 2008, we received approximately \$3.6 million in federal income taxes paid during the tax years ended June 30, 2007 and 2006, as a result of the carry-back of our 2008 income tax loss. Significant intangible drilling costs were incurred during the 2008 fiscal year, of which, we elected to deduct (expense) approximately \$10.9 million for federal and state income tax purposes. Under GAAP, and specifically the full-cost accounting method, intangible drilling costs are capitalized as part of oil and natural gas properties, and depleted using the unit-of-production method. The deduction of intangible drilling costs resulted in a significant difference in the income tax and book basis of our oil and natural gas properties, which resulted in an increase in our net deferred tax liability as of June 30, 2009.

At June 30, 2009, we have a federal tax loss carryforward of approximately \$15.9 million we acquired through reverse merger in May 2004, of which, approximately \$0.6 million is available to us to use in equal amounts through 2023. We have applied a valuation allowance against the portion of the federal tax loss carryforward that has been disallowed through IRC Section 382.

#### Note 11 — Related Party Transactions

Laird Q. Cagan, a member of our Board of Directors, is a Managing Director and co-owner of Cagan McAfee Capital Partners, LLC (“CMCP”). CMCP has performed financial advisory services to us pursuant to a written agreement amended in November 2005 (the “Agreement”), providing for a retainer of \$5,000 per month. Also pursuant to the Agreement, Mr. Cagan, as a registered representative of Chadbourn Securities Inc. (“Chadbourn”) and as a partner of CMCP could serve as our placement agent in private equity financings, wherein CMCP could earn cash fees equal to 8% of gross equity proceeds, declining to 4% subject to the amount of equity raised through CMCP, and a fixed 4% warrant fee. During the term of the Agreement, Mr. Cagan received no compensation for serving as a director or as the Chairman of our Board of Directors. Effective December 31, 2008, the Agreement was modified to remove the monthly retainer and Mr. Cagan was re-elected as a director of our Board with remuneration consistent with other outside directors of our Board.

Eric A. McAfee, a major shareholder of the Company, is also a Managing Director of CMCP.

During the year ended June 30, 2009, we expensed and paid \$30,000, through monthly retainers of \$5,000 through December 31, 2008. During the year ended June 30, 2008, we expensed and paid CMCP \$60,000, through monthly retainers of \$5,000. There were no other earned fees by CMCP during these periods.

See also Note 7 for equity transactions with related parties.

#### Note 12 — Net loss Per Share

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

	Year Ended June 30,	
	2009	2008
<i>Numerator</i>		
Net loss	\$ (2,601,593)	\$ (1,570,974)
<i>Denominator</i>		
Weighted average number of common shares — basic and diluted	26,366,677	26,786,270
Net Loss per common share — basic and diluted	\$ (0.10)	\$ (0.06)

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### EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

#### Note 12 — Net loss Per Share (Continued)

As of June 30, 2009, there were 390,283 shares of unvested Restricted Stock outstanding. Other outstanding potentially dilutive securities as of June 30, 2009 are as follows:

<u>Outstanding Potential Dilutive Securities</u>	<u>Weighted Average Exercise Price</u>	<u>Outstanding at June 30, 2009</u>
Common stock warrants issued in connection with equity and financing transactions	\$ 1.46	348,058
Stock Options and Incentive Warrants	\$ 1.83	5,485,820
Total	\$ 1.81	5,833,878

As of June 30, 2008, there were 50,898 shares of unvested Restricted Stock outstanding. Other outstanding potentially dilutive securities as of June 30, 2008 are as follows:

<u>Outstanding Potential Dilutive Securities</u>	<u>Weighted Average Exercise Price</u>	<u>Outstanding at June 30, 2008</u>
Common stock warrants issued in connection with equity and financing transactions	\$ 1.40	401,058
Stock Options and Incentive Warrants	\$ 1.81	5,483,500
Total	\$ 1.78	5,884,558

#### Note 13 — Commitments and Contingencies

We are subject to various claims and contingencies in the normal course of business. In addition, from time to time, we receive communications from government or regulatory agencies concerning investigations or allegations of noncompliance with laws or regulations in jurisdiction in which we operate. We disclose such matters if we believe it is reasonably possible that a future event or events will confirm a loss through impairment of an asset or the incurrence of a liability. We establish reserves if we believe it is probable that a future event or events will confirm a loss and we can reasonably estimate such loss. Furthermore, we will disclose any matter that is unasserted if we consider it probable that a claim will be asserted and there is a reasonable possibility

that the outcome will be unfavorable. As of June 30, 2009, and subsequently through the date these financial statements were available to be issued, no claim or unasserted claim existed that required an accrual or disclosure, except for that which has been disclosed.

**Litigation.** In November 2005, a multi-plaintiff lawsuit was filed in the Fifth Judicial District Court, Richland Parish, Louisiana, against 18 defendants including NGS Sub Corp. and Arkla Petroleum LLC, the Company's direct and indirect wholly owned subsidiaries (the "Subsidiaries"), as working interest owners/operators of various oil and natural gas leases in the Delhi Field. Plaintiffs claimed that the defendants' oil and natural gas exploration, development and production activities on their properties had caused soil and ground water contamination as a result of the release of hydrocarbons and drilling fluids.

In July 2009 all claims filed against the Subsidiaries, along with eleven other previous operators and owners of the Delhi Field, were dismissed following settlement. Our obligations under the settlement are limited to a cash contribution to the cost of completing certain lease remediation operations. The amount of the cash contribution is contractually limited, and the maximum contribution was charged to general and administrative expense during the year ended June 30, 2009. In exchange for the cash contribution, our Subsidiaries received a waiver of any indemnity claim by the active predecessor operator, who is obligated to carry out the remediation operations. Although other previous operators may attempt to assert indemnity claims against subsequent operators for their settlement costs, including the indirect subsidiary of the Company that operated the field, the Company believes that such claims against its indirect operating subsidiary would be without merit.

**Lease Commitments.** We have a non-cancelable operating lease for office space that expires on August 1, 2016. Future minimum lease commitments as of June 30, 2009 under this operating lease are as follows:

<u>For the year ended June 30,</u>	
2010	\$ 138,089
2011	138,089
2012	157,268
2013	159,011
2014	159,011
Thereafter	331,272
<b>Total</b>	<b>\$ 1,082,740</b>

Rent expense for the year ended June 30, 2009 and 2008 was \$149,397 and \$141,866, respectively.

**Employment Contracts.** We have entered into employment agreements with the Company's three senior executives. The employment contracts provide for a severance package for termination by the Company for any reason other than cause or permanent disability, or in the event of a constructive termination, that includes payment of base pay and certain medical and disability benefits from six months to a year after termination. The total contingent obligation under the employment contracts as of June 30, 2009 is approximately \$499,000.

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**EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES  
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

**Note 14 — Concentrations of Credit Risk**

**Major Customers.** We market substantially all of our oil and natural gas production from the properties we operate. The majority of our operated gas, oil and condensate production is sold to a variety of purchasers under short-term (less than 12 months) contracts at market-based prices. The following table identifies customers from whom we derived 10 percent or more our net oil and natural gas revenues during the years ended June 30, 2009 and 2008. Based on the current demand for oil and natural gas and availability of other customers, we do not believe the loss of any of these customers would have a significant affect on our operations or financial condition.

<u>Customer</u>	<u>Percent of Total Revenue</u>	
	<u>Year Ended June 30, 2009</u>	<u>Year Ended June 30, 2008</u>
Plains Marketing L.P.	40%	67%
ETC Texas Pipeline, LTD.	36%	26%
DCP Midstream, LP	16%	—

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

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

**Note 15 — Retirement Plan**

Effective February 1, 2007, we implemented a 401(k) Savings Plan which covers all employees. At our discretion, we may match a certain percentage of the employees' contributions to the plan. The matching percentage is currently 100% of the first 4% of each participant's compensation, vesting fully upon our contributions. Our matching contribution to the plan was \$58,884 and \$59,437 for the years ended June 30, 2009 and 2008, respectively.

**Note 16 — Subsequent Events**

On September 8, 2009, the Board of Directors authorized and the Company issued 138,224 shares of common stock from the 2004 Stock Plan to certain employees for the payment of fiscal 2009 bonuses. The value of the shares issued were \$370,440, based on the fair market value on the date of issuance, or

\$2.68 per share. The amount of bonus was accrued as of June 30, 2009 and recognized as a long term liability. On September 8, 2009, the liability was reclassified as additional paid-in capital.

On September 8, 2009, the Board of Directors authorized and the Company issued 324,597 shares of restricted common stock from the 2004 Stock Plan to certain employees as a long-term incentive award. Total unrecognized stock-based compensation expense of \$869,917 related to the long-term incentive award will be recognized ratably over a four year period as the restricted common stock vests.

Subsequent events have been evaluated through September 23, 2009, the date these financial statements were available to be issued.

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**EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES  
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

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

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

The following table summarizes costs incurred and capitalized in oil and natural gas property acquisition, exploration and development activities. Property acquisition costs are those costs incurred to lease property, including both undeveloped leasehold and the purchase of reserves in place. Exploration costs include costs of identifying areas that may warrant examination and examining specific areas that are considered to have prospects containing oil and natural gas reserves, including costs of drilling exploratory wells, geological and geophysical costs and carrying costs on undeveloped properties. Development costs are incurred to obtain access to proved reserves, including the cost of drilling. Development costs also include amounts incurred due to the recognition of asset retirement obligations, of \$502,814 and \$207,748, during the years ended June 30, 2009 and 2008, respectively.

	<u>For the Years Ended June 30</u>	
	<u>2009</u>	<u>2008</u>
<b>Oil and Natural Gas Activities</b>		
Property acquisition costs:		
Proved property	\$ 876,640	\$ 2,958,538
Unproved property	1,413,941	5,648,955
Exploration costs	349,403	—
Development costs	6,486,158	13,216,175
<b>Total costs incurred for oil and natural gas activities</b>	<b>\$ 9,126,142</b>	<b>\$ 21,823,668</b>

***Estimated Net Quantities of Proved Oil and Natural Gas Reserves (Unaudited)***

Proved oil and natural gas reserves are estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and natural gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. There are uncertainties inherent in estimating quantities of proved oil and natural gas reserves, projecting future production rates, and timing of development expenditures. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered. All of our proved reserves are located in the United States. The following information about our proved and proved developed oil and natural gas reserves was developed from reserve reports prepared by independent reserve engineers:

	<u>Crude Oil (Bbls)</u>	<u>Natural Gas Liquids (Bbls)</u>	<u>Natural Gas (Mcf)</u>	<u>BOE</u>
July 1, 2007	1,084,200	—	3,838,000	1,723,867
Revisions of previous estimates	(298,793)	274,699	(1,013,358)	(192,987)
Purchases of minerals in place	629,700	1,046,400	7,778,800	2,972,567
Production (sales volumes)	(29,466)	(10,639)	(69,051)	(51,614)
Sales of minerals in place	(433,600)	—	—	(433,600)
July 1, 2008	952,041	1,310,460	10,534,391	4,018,233
Revisions of previous estimates	(92,729)	(272,689)	(4,498,026)	(1,115,089)
Purchases of minerals in place	122,662	60,648	645,724	290,931
Production (sales volumes)	(36,026)	(44,125)	(323,301)	(134,035)
July 1, 2009	945,948	1,054,294	6,358,788	3,060,040
<b>Proved developed reserves:</b>				
July 1, 2007	389,700	—	—	389,700
July 1, 2008	96,167	109,716	561,001	299,383
July 1, 2009	104,731	141,372	1,106,028	430,441

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**EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES  
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**



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

The revisions of previous estimates during our fiscal year ended June 30, 2009, were due primarily to the decline in the price of natural gas. During the year ended June 30, 2008, the revisions of previous estimates were primarily due to the identification and separation of natural gas liquids in 2008 and the effects of the new SEC guideline on PUD locations with fractured reservoirs. Natural gas liquids were not separately identified in the July 1, 2007 independent report prepared by Von Gonten.

Purchases of minerals in place during 2009 resulted from leasehold acquisitions of proved undeveloped reserves in the Giddings Field and in our Neptune oil project in South Texas.

Purchases of minerals in place during 2008 resulted from leasehold acquisitions of proved undeveloped reserves that directly offset currently or historically productive wells in the same fracture trend in the Giddings Field.

**Standardized Measure of Discounted Future Net Cash Flows**

Future oil and natural gas sales and production and development costs have been estimated using prices and costs in effect at the end of the years indicated, as required by SFAS No. 69, *Disclosures about Oil and Gas Producing Activities* (“SFAS No. 69”). SFAS No. 69 requires that net cash flow amounts be discounted at 10%. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing our proved oil and natural gas reserves assuming continuation of existing economic conditions. Future income tax expenses are computed by applying the appropriate period-end statutory tax rates to the future pretax net cash flow relating to our proved oil and natural gas reserves, less the tax basis of the related properties. The future income tax expenses do not give effect to tax credits, allowances, or the impact of general and administrative costs of ongoing operations relating to the Company’s proved oil and natural gas reserves. Changes in the demand for oil and natural gas, inflation, and other factors make such estimates inherently imprecise and subject to substantial revision. The table below should not be construed to be an estimate of the current market value of the our proved reserves.

The standardized measure of discounted future net cash flows related to proved oil and natural gas reserves as of June 30, 2009 and 2008 are as follows:

	<b>For the Years Ended June 30</b>	
	<b>2009</b>	<b>2008</b>
Future cash inflows	\$ 127,639,699	\$ 390,107,980
Future production costs and severance taxes	(36,128,247)	(61,351,774)
Future development costs	(33,317,000)	(62,457,700)
Future income tax expenses	(15,697,532)	(95,022,328)
Future net cash flows	42,496,920	171,276,178
10% annual discount for estimated timing of cash flows	(18,947,129)	(74,203,537)
Standardized measure of discounted future net cash flows	<u>\$ 23,549,791</u>	<u>\$ 97,072,641</u>

The following table presents the NYMEX spot crude oil, natural gas liquid, and natural gas price used to compute future cash inflows for each period:

	<b>2009</b>	<b>2008</b>
Crude oil price per barrel	\$ 69.890	\$ 140.000
Natural gas liquids price per barrel *	\$ 36.960	\$ 84.390
Natural gas price per MMBtu	\$ 3.885	\$ 13.095

\* The NGL price was based on the historical price received versus the NYMEX basis oil price.

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**EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES  
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

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

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

	<b>For the Years Ended June 30</b>	
	<b>2009</b>	<b>2008</b>
Balance, beginning of year	\$ 97,072,641	\$ 21,990,298
Net changes in sales prices and production costs related to future production	(145,566,788)	19,582,657
Changes in estimated future development costs	24,399,826	(27,754,046)
Sales of oil and gas produced during the period, net of production costs	(4,654,400)	(2,910,089)
Net change due to purchases of minerals in place	2,683,261	146,355,022
Net change due to sales of minerals in place	—	(7,302,851)
Net change due to revisions in quantity estimates	(20,564,731)	(5,791,427)
Development costs incurred during the period	5,960,423	2,000,000
Accretion of discount	13,315,725	2,746,274
Net change in discounted income taxes	50,903,834	(51,843,197)
Balance, end of year	<u>\$ 23,549,791</u>	<u>\$ 97,072,641</u>

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

None.

**Item 9A. Controls and Procedures****Disclosure Controls and Procedures**

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

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

**Management's Report on Internal Control Over Financial Reporting**

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) of the Securities Exchange Act of 1934, as a process designed by, or under the supervision of, the company's principal executive and principal financial officers and effected by the Company's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America and includes those policies and procedures that:

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Under the supervision and with the participation of management, including the Chief Executive Officer and the Chief Financial Officer, an evaluation was conducted on the effectiveness of the Company's internal control over financial reporting based on criteria established in the Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management concluded that the Company maintained effective internal control over financial reporting as of June 30, 2009.

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This annual report does not include an attestation report of the Company's registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by the Company's registered public accounting firm pursuant to temporary rules of the Securities and Exchange Commission that permit the Company, as a smaller reporting company, to provide only management's report in this annual report.

**Changes in Internal Control Over Financial Reporting**

There has been no change in the Company's internal control over financial reporting during the year ended June 30, 2009 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

**Item 9B. Other Information**

None.

**PART III****Item 10. Directors, Executive Officers And Corporate Governance**

Incorporated by reference to the Company's Proxy Statement to be filed with the Commission pursuant to Regulation 14A within 120 days of the end of the Company's 2009 fiscal year.

### **Item 11. Executive Compensation**

Incorporated by reference to the Company's Proxy Statement to be filed with the Commission pursuant to Regulation 14A within 120 days of the end of the Company's 2009 fiscal year.

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

Incorporated by reference to the Company's Proxy Statement to be filed with the Commission pursuant to Regulation 14A within 120 days of the end of the Company's 2009 fiscal year.

### **Item 13. Certain Relationships and Related Transactions, Director Independence**

Incorporated by reference to the Company's Proxy Statement to be filed with the Commission pursuant to Regulation 14A within 120 days of the end of the Company's 2009 fiscal year.

### **Item 14. Principal Accountant Fees and Services**

Incorporated by reference to the Company's Proxy Statement to be filed with the Commission pursuant to Regulation 14A within 120 days of the end of the Company's 2009 fiscal year.

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## **PART IV.**

### **Item 15. Exhibits and Financial Statement Schedules**

The following documents are filed as part of this report:

**1. Financial Statements.**

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

Report of Independent Registered Public Accounting Firm

Consolidated Balance Sheets

Consolidated Statements of Operations

Consolidated Statements of Cash Flows

Consolidated Statements of Stockholders' Equity

Notes to the Consolidated Financial Statements

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

None.

**3. Exhibits**

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

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## **SIGNATURES**

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

### **Evolution Petroleum Corporation**

By: /s/ ROBERT S. HERLIN  
Robert S. Herlin  
Chairman, President and Chief Executive Officer  
(Principal Executive Officer)

By: /s/ STERLING H. MCDONALD

Date: September 23, 2009

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

Date	Signature	Title
September 23, 2009	/s/ EDWARD J. DIPAOLO Edward J. DiPaolo	Director
September 23, 2009	/s/ GENE STOEVER Gene Stoever	Director
September 23, 2009	/s/ WILLIAM DOZIER William Dozier	Director
September 23, 2009	/s/ KELLY W. LOYD Kelly W. Loyd	Director
September 23, 2009	/s/ LAIRD Q. CAGAN Laird Q. Cagan	Director
September 23, 2009	/s/ ROBERT S. HERLIN Robert S. Herlin	Chairman of the Board

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## INDEX OF EXHIBITS

### MASTER EXHIBIT INDEX

EXHIBIT NUMBER	DESCRIPTION
2.1	Asset Purchase Agreement for Tullos Field, dated September 3, 2004 (Previously filed as an exhibit to Form 8-K on September 9, 2004)
2.2	Definitive Asset Purchase Agreement, dated as of February 2, 2005, by and between Chadco, Inc., Alan Chadwick McCartney, Sonya McCartney and NGS Sub. Corp. (Previously filed as an exhibit in Form 8-K on February 8, 2005)
2.3	Purchase and Sale Agreement, by and between NGS Sub Corp. and Denbury Onshore, LLC, dated May 8, 2006 (Previously filed as an exhibit to Form 8-K on May 11, 2006)
2.4	Purchase and Sale Agreement I, by and between NGS Sub Corp. and Denbury Onshore, LLC, dated May 8, 2006 (Previously filed as an exhibit to Form 8-K on June 16, 2006)
2.5	Purchase and Sale Agreement II, by and between NGS Sub Corp. and Denbury Onshore, LLC, dated May 8, 2006 (Previously filed as an exhibit to Form 8-K on June 16, 2006)
2.6	Conveyance, Assignment and Bill of Sale Agreement, by and between NGS Sub Corp. and Denbury Onshore, LLC, dated May 8, 2006 (Previously filed as an exhibit to Form 8-K on June 16, 2006)
2.7	Agreement and Plan of Reorganization dated as of April 12, 2004 among Reality Interactive, Inc., Reality Acquisition Corp., Global Marketing Associates, Inc., Dean H. Becker and Natural Gas Systems, Inc. (incorporated by reference to the Current Report on Form 8-K/A filed by Natural Gas Systems, Inc. with the Securities and Exchange Commission on April 27, 2004) (Previously filed as an exhibit to Form Schedule 13D on July 11, 2008)
3.1	Articles of Incorporation (Previously filed as an exhibit to the Company's Current Report on Form 8-K on February 7, 2002)
3.2	Certificate of Amendment to Articles of Incorporation (Previously filed as an exhibit to the Company's Current Report on Form 8-K on February 7, 2002)
3.3	Certificate of Amendment to Articles of Incorporation (Previously filed as an exhibit to Form SB 2/A on October 19, 2005)
3.4	Bylaws (Previously filed as an exhibit to the Company's Current Report on Form 8-K on February 7, 2002)
3.5	Amended Bylaws (Previously filed as an exhibit to Form 10KSB on March 31, 2004)

- 4.1 Form of Stock Option Agreement for the Natural Gas Systems 2004 Stock Plan (Previously filed as an exhibit to the Current Report on Form 8—K on April 8, 2005)
- 4.2 Articles of Merger (Previously filed as an exhibit to Form SB — 2/A on October 19, 2005)
- 4.3 Form of Warrant Agreement between Natural Gas Systems, Inc. and Tatum CFO Partners, LLP (Previously filed as an exhibit to the Company’s Current Report on Form 8-K on April 8, 2005)
- 4.4 Revocable Warrant Agreement between Natural Gas Systems, Inc. and Daryl V. Mazzanti (Previously filed as an exhibit to the Company’s Current Report on Form 8-K on June 29, 2005)
- 4.5 Specimen form of the Company’s Common Stock Certificate (Previously filed herewith as an exhibit to Form SB — 2/A on October 19, 2005)
- 4.6 Securities Purchase Agreement dated as of May 6, 2005, by and between Natural Gas Systems, Inc. and Rubicon Master Fund (Previously filed as an exhibit to the Company’s Current Report on Form 8-K on May 11, 2005)
- 4.7 Registration Rights Agreement dated as of May 6, 2005, by and between Natural Gas Systems, Inc. and Rubicon Master Fund (Previously filed as an exhibit to the Company’s Current Report on Form 8-K on May 11, 2005)

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- 4.8 Stock Grant Agreement, dated as of May 4, 2005, by and between Natural Gas Systems, Inc. and Liviakis Financial Communications, Inc. (Previously filed as an exhibit to the Company’s Current Report on Form 8-K on May 11, 2005)
- 4.9 Herlin Stock Option Agreement, dated April 4, 2005 (Previously filed as an exhibit to the Company’s Current Report on Form 8-K on April 8, 2005)
- 4.10 Revocable Warrant Agreement between Natural Gas Systems, Inc. and Robert S. Herlin, dated April 4, 2005 (Previously filed as an exhibit to the Company’s Current Report on Form 8-K on April 8, 2005)
- 4.11 Amended and Restated Tatum Resources Agreement, dated January 1, 2005 (Previously filed as an exhibit to the Company’s Current Report on Form 8-K on April 8, 2005)
- 4.12 Warrant Agreement between Natural Gas Systems, Inc. and Tatum CFO Partners, LLP, dated January 1, 2005 (Previously filed as an exhibit to the Company’s Current Report on Form 8-K on April 8, 2005)
- 4.13 McDonald Stock Option Agreement, dated April 4, 2005 (Previously filed as an exhibit to the Company’s Current Report on Form 8-K on April 8, 2005)
- 4.14 Warrant Agreement, dated as of February 2, 2005, between Natural Gas Systems, Inc. and Prospect Energy Corporation (Previously filed as an exhibit to the Company’s Current Report on Form 8-K on February 8, 2005)
- 4.15 Natural Gas Systems, Inc. Common Stock Purchase Warrant in favor of Prospect Energy Corporation, dated as of February 2, 2005 (Previously filed as an exhibit to the Company’s Current Report on Form 8-K on February 8, 2005)
- 4.16 Revocable Warrant Agreement, dated as of February 2, 2005, between Natural Gas Systems, Inc. and Prospect Energy Corporation (Previously filed as an exhibit to the Company’s Current Report on Form 8-K on February 8, 2005)
- 4.17 Natural Gas Systems, Inc. Revocable Common Stock Purchase Warrant in favor of Prospect Energy Corporation, dated as of February 2, 2005 (Previously filed as an exhibit to the Company’s Current Report on Form 8-K on February 8, 2005)
- 4.18 Registration Rights Agreement, dated as of February 2, 2005, between Natural Gas Systems, Inc. and Holders of Common Stock of Natural Gas Systems, Inc. (Previously filed as an exhibit to the Company’s Current Report on Form 8-K on February 8, 2005)
- 4.19 Form of Registration Rights Agreement (Previously filed as an exhibit to the Company’s Current Report on Form 8-K on October 26, 2004)
- 4.20 2004 Stock Plan (Previously filed as an exhibit to the Company’s Definitive Information Statement on Schedule 14C on August 9, 2004)
- 4.21 2003 Stock Option Plan, adopted September 25, 2003 (Previously filed as an exhibit to the Company’s Form 8-K on January 24, 2007)
- 4.22 Second Revocable Warrant Agreement , dated as of September 27, 2005, between Natural Gas Systems, Inc. and Prospect Energy Corporation (Previously filed as an exhibit to the Company’s Report on Form 10-KSB on September 28, 2005)
- 4.23 Stock Option Agreement, dated June 23, 2005 between Natural Gas Systems, Inc. and Daryl V. Mazzanti (Previously filed as an exhibit to the Company’s Current Report on Form 8-K on June 29, 2005)
- 4.24 Stock Option Grant Agreement, dated June 23, 2005 between Natural Gas Systems, Inc. and Daryl V. Mazzanti (Previously filed as an exhibit to the Company’s Current Report on Form 8-K on June 29, 2005)

- 4.25 Securities Purchase Agreement dated as of January 13, 2006, by and between Natural Gas Systems, Inc. and Rubicon Master Fund (Previously filed as an exhibit to the Company's Current Report on Form 8-K on January 20, 2006)
- 4.26 Amended and Restated Registration Rights Agreement dated as of January 13, 2006, by and between Natural Gas Systems, Inc. and Rubicon Master Fund (Previously filed as an exhibit to the Company's Current Report on Form 8-K on January 20, 2006)
- 4.27 Third Revocable Warrant Agreement, by and between Prospect Energy Corporation and Natural Gas Systems, Inc., dated January 31, 2006 (Previously filed as an exhibit to Form SB — 2/A on March 3, 2006)

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- 4.28 Amendment No. 1 to the Registration Rights Agreement, by and between Prospect Energy Corporation and Natural Gas Systems, Inc., dated January 31, 2006 (Previously filed as an exhibit to Form SB — 2/A on March 3, 2006)
- 4.29 Subordinated Promissory Note, dated March 3, 2006, between Natural Gas Systems, Inc. and Laird Q. Cagan (Previously filed as an exhibit to Form 8-K on March 8, 2006)
- 4.30 Form of Restricted Stock Agreement (Previously filed as an exhibit to the Company's Schedule TO on May 15, 2009)
- 10.1 Third Amendment to Consulting Agreement between Liviakis Financial Communications, Inc. and Evolution Petroleum dated November 14, 2006 (Previously filed as an exhibit to Form 10-QSB on February 14, 2007)
- 10.2 Executive Employment Agreement of Robert S. Herlin, dated April 4, 2005 (Previously filed as an exhibit to Form 8-K on April 8, 2005)
- 10.3 Executive Employment Agreement of Sterling H. McDonald, dated April 4, 2005 (Previously filed as an exhibit to Form 8-K on April 8, 2005)
- 10.4 Executive Employment Agreement of Daryl V. Mazzanti, dated June 23, 2005 (Previously filed as an exhibit to Form 8-K on June 29, 2005)
- 10.5 Master Services Agreement, dated September 29, 2005, by and between the NGS Technologies, Inc. and MTEM, Ltd. (Previously filed as an exhibit on Form 8-K on October 7, 2005)
- 10.6 Agreement with Chadbourn Securities, Inc., dated February 13, 2006 (Previously filed as an exhibit to Form 10QSB on February 14, 2006)
- 10.7 Agreement with Cagan McAfee Capital Partners, LLC, dated February 13, 2006 (Previously filed as an exhibit to Form 10QSB on February 14, 2006)
- 10.8 Unit Operating Agreement, by and between NGS Sub Corp. and Denbury Onshore, LLC, dated May 8, 2006 (Previously filed as an exhibit to Form 8-K on June 16, 2006)
- 10.9 Form of Indemnification Agreement for Officers and Directors, as adopted on September 20, 2006 (Previously filed as an exhibit to Form 8-K on September 22, 2006)
- 10.10 Asset Purchase and Sale Agreement by and between NGS SUB. CORP. (Seller) and MWM Energy, LLC (Buyer), dated February 15, 2008 (Previously filed as an exhibit to Form 10-Q on May 14, 2008)
- 10.11 Evolution Petroleum Corporation Amended and Restated 2004 Stock Plan (Previously filed as Annex A to Form Schedule 14A on October 29, 2007)
- 10.12 Gas Purchase and Gas Processing Contract by and between EVOLUTION OPERATION CO., INC. (Seller) and ETC TEXAS PIPELINE LTD. (Buyer) dated October 8, 2007 (Previously filed as an exhibit to Form 10-K/A on April 7, 2009)
- 10.13 Gas Purchase Contract by and between EVOLUTION OPERATION CO., INC. (Seller) and DCP MIDSTREAM, LP (Buyer) dated December 1, 2007 (Previously filed as an exhibit to Form 10-K/A on April 7, 2009)
- 10.14 Gas Purchase and Sale Agreement by and between EVOLUTION OPERATION CO., INC. (Seller) and COPANO FIELD SERVICES/UPPER GULF COAST, L.P. (Buyer) dated February 1, 2009 (Previously filed as an exhibit to Form 10-Q on May 15, 2009)
- 14.1 Code of Business Conduct and Ethics for Natural Gas Systems, Inc. (Previously filed as an exhibit to Form 8-K on May 4, 2006)
- 21.1 List of Subsidiaries of Evolution Petroleum Corporation (Filed herein)
- 23.1 Consent of Hein & Associates, LLP, independent auditors (Filed herein)
- 23.2 Consent of W. D. Von Gonten & Co. (Filed herein)
- 31.1 Certification of Chief Executive Officer Robert S. Herlin Pursuant to Rule 15D-14 of the Securities Exchange Act of 1934, as Amended as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (Filed herein)

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31.2	Certification of Chief Financial Officer Sterling H. McDonald Pursuant to Rule 15D-14 of the Securities Exchange Act of 1934, as Amended as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (Filed herein)
32.1	Certification of Chief Executive Officer Robert S. Herlin Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Filed herein)
32.2	Certification of Chief Financial Officer Sterling H. McDonald Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Filed herein)
99.1	Audit Committee Charter of the Board of Directors of Natural Gas Systems, Inc. (Previously filed as an exhibit to Form 8-K on May 4, 2006)
99.2	Compensation Committee Charter of the Board of Directors of Natural Gas Systems, Inc. (Previously filed as an exhibit to Form 8-K on May 4, 2006)
99.3	Nominating Committee Charter of the Board of Directors of Natural Gas Systems, Inc. (Previously filed as an exhibit to Form 8-K on May 4, 2006)

## List of Subsidiaries

**Evolution Petroleum Corporation — A Nevada Corporation**Officers:

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

Directors:

Robert S. Herlin, Chairman  
Laird Q. Cagan  
Jed DiPaolo  
Gene Stoever  
William Dozier  
Kelly Loyd

**NGS Sub. Corp. — A Delaware Corporation**Officers:

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

Directors:

Robert S. Herlin  
Sterling H. McDonald

**Arkla Petroleum, L.L.C. — A Louisiana Corporation**

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

**NGS Technologies, Inc. — A Delaware Corporation**Officers:

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

Directors:

Robert S. Herlin

**Evolution Operating Co. Inc. — A Texas Corporation**Officers:

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

Directors:

Robert S. Herlin  
Sterling H. McDonald

**Tertiaire Resources Company — A Texas Corporation**Officers:

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

Directors:

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

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CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTANT'S CONSENT

We hereby consent to the incorporation by reference in the Registration Statements filed on Form S-8 and Form S-3 of our report dated September 23, 2009, relating to the financial statements of Evolution Petroleum Corporation and subsidiaries appearing in the Form 10-K for the period ended June 30, 2009.

/s/ Hein & Associates LLP

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Hein & Associates LLP

Houston, Texas  
September 23, 2009

500 Dallas, Suite 2900  
Houston, Texas 77002  
Phone: 713-850-9814  
Fax: 713-850-0725  
[www.heincpa.com](http://www.heincpa.com)

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## CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

We The firm of W.D. Von Gonten & Co. consents to the use of its name and to the use of its report regarding Evolution Petroleum Corporation Proved Reserves and Future Net Revenues "as of July 1, 2005 through July 1, 2009" in the relevant pages of the Form 10-K of Evolution Petroleum Corporation for the fiscal year ended June 30, 2009.

W.D. Von Gonten & Co. has no interests in Evolution Petroleum Corporation or in any affiliated companies or subsidiaries and has not received any such interest as payment for such reports and has no director, officer or employee otherwise connected with Evolution Petroleum Corporation. Evolution Petroleum Corporation does not employ us on a contingent basis.

Yours truly,

/s/ William D. Von Gonten, Jr.  
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W.D. VON GONTEN & CO.

By: William D. Von Gonten, Jr.  
TX #73244  
Its: President

September 21, 2009

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**CERTIFICATION PURSUANT TO RULE 13A-14 and 15D-14 OF THE SECURITIES EXCHANGE ACT OF 1934,  
AS AMENDED AS ADOPTED PURSUANT TO SECTION 302  
OF THE SARBANES-OXLEY ACT OF 2002**

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

1. I have reviewed this annual report on Form 10-K of Evolution Petroleum Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this report;
4. The Registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Registrant and have:
  - a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
  - b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
  - c) Evaluated the effectiveness of the Registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
  - d) Disclosed in this report any change in the Registrant's internal control over financial reporting that occurred during the Registrant's most recent fiscal quarter (the Registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the Registrant's internal control over financial reporting; and
5. The Registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Registrant's auditors and the audit committee of the Registrant's Board of Directors (or persons performing the equivalent functions):
  - a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Registrant's ability to record, process, summarize and report financial information; and
  - b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant's internal control over financial reporting.

Date: September 23, 2009

/s / ROBERT S. HERLIN

Robert S. Herlin  
Chairman, President and Chief Executive Officer

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**CERTIFICATION PURSUANT TO RULE 13A-14 and 15D-14 OF THE SECURITIES EXCHANGE ACT OF 1934,  
AS AMENDED AS ADOPTED PURSUANT TO SECTION 302  
OF THE SARBANES-OXLEY ACT OF 2002**

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

1. I have reviewed this annual report on Form 10-K of Evolution Petroleum Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this report;
4. The Registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Registrant and have:
  - a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
  - b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
  - c) Evaluated the effectiveness of the Registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
  - d) Disclosed in this report any change in the Registrant's internal control over financial reporting that occurred during the Registrant's most recent fiscal quarter (the Registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the Registrant's internal control over financial reporting; and
5. The Registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Registrant's auditors and the audit committee of the Registrant's Board of Directors (or persons performing the equivalent functions):
  - a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Registrant's ability to record, process, summarize and report financial information; and
  - b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant's internal control over financial reporting.

Date: September 23, 2009

/s / STERLING H. MCDONALD

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Sterling H. McDonald  
Vice-President and Chief Financial Officer

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

The undersigned, Robert S. Herlin, President and Chief Executive Officer of Evolution Petroleum Corporation (the "Company"), certifies in connection with the filing with the Securities and Exchange Commission of the Company's Annual Report on Form 10-K for the year ended June 30, 2009 (the "Report") pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to his knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

IN WITNESS WHEREOF, the undersigned has executed this certification as of the 23<sup>rd</sup> day of September, 2009.

/s/ ROBERT S. HERLIN

Robert S. Herlin

President and Chief Executive Officer

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

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

The undersigned, Sterling H. McDonald, Vice-President and Chief Financial Officer of Evolution Petroleum Corporation (the "Company"), certifies in connection with the filing with the Securities and Exchange Commission of the Company's Annual Report on Form 10-K for the year ended June 30, 2009 (the "Report") pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to his knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

IN WITNESS WHEREOF, the undersigned has executed this certification as of the 23<sup>rd</sup> day of September, 2009.

/s/ STERLING H. MCDONALD

Sterling H. McDonald

Vice-President and Chief Financial Officer

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

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