UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-KSB

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

For the fiscal year ended June 30, 2007

o TRANSITION REPORT UNDER SECTION 13 OR 15 (d) OF THE EXCHANGE ACT

For the transition period to

Commission file number: 001-32942

EVOLUTION PETROLEUM CORPORATION
(Name of small business issuer in its charter)

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

2500 City West Blvd., Suite 1300, Houston, Texas 77042
(Address of principal executive offices and zip code)

(713) 935-0122
(Issuer's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Exchange Act:

Title of each class	Name of exchange on which registered
Common Stock, par value $.001 per share	**American Stock Exchange**

Securities registered pursuant to Section 12(g) of the Exchange Act: **None**

Check whether the issuer is not required to file reports pursuant to Section 13 or 15(d) of the Exchange Act. o

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

Check if there is no disclosure of delinquent filers in response to Item 405 of Regulation S-B contained in this form, and no disclosure will 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-KSB or any amendment to this Form 10-KSB. o

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

State issuer's revenues for its most recent fiscal year: $1,866,878

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant was approximately $39 million as of September 20, 2007 based upon the closing price of the common stock on the American Stock Exchange on September 20, 2007 of $2.98 per share.

APPLICABLE ONLY TO CORPORATE REGISTRANTS

State the number of shares outstanding of each of the issuer's classes of common equity, as of the latest practicable date.

26,776,234 Shares of Common Stock outstanding at September 20, 2007

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Company's Proxy Statement for the 2007 Annual Meeting of Shareholders are incorporated by reference in Part III.

Transitional Small Business Disclosure Format (Check one): Yes: o No: x

**EVOLUTION PETROLEUM
CORPORATION AND SUBSIDIARIES**

2007 ANNUAL REPORT ON 10-KSB

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Forward-Looking Statements

As used in this Annual Report on Form 10-KSB, the terms "Evolution", "EPM", "Company", "we", "us", "our" and similar terms refer to Evolution Petroleum Corporation, a Nevada Corporation formerly known as Natural Gas Systems, Inc. (Nevada, "NGS"), and its subsidiaries, unless the context indicates otherwise.

This Annual Report on Form 10-KSB contains "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act and Section 21E of the Exchange Act. Forward-looking statements give our current expectations or forecasts of future events. They include statements regarding our future operating and financial performance. Although we believe the expectations and forecasts reflected in these and other forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. You should understand that the following important factors, could affect our future results and could cause those results or other outcomes to differ materially from those expressed or implied in the forward-looking statements relating to: (1) amount, nature and timing of capital expenditures; (2) drilling of wells and other planned exploitation activities; (3) timing and amount of future production of oil and natural gas; (4) increases in production growth and proved reserves; (5) operating costs such as lease operating expenses, administrative costs and other expenses; (6) our future operating or financial results; (7) cash flow and anticipated liquidity; (8) our business strategy, including the availability of leasing opportunities; (9) hedging strategy; (10) exploration and exploitation activities and property acquisitions; (11) marketing of oil and natural gas; (12) governmental and environmental regulation of the oil and gas industry; (13) environmental liabilities relating to any pollution arising from our operations, net of any insurance proceeds; (14) our level of indebtedness; (15) timing and amount of future dividends; (16) industry competition, conditions, performance and consolidation; (17) natural events such as severe weather, hurricanes, floods, fire and earthquakes; (18) availability of drilling rigs and other oil field equipment and services; (19) our inability to control the development, production and operations of our non-operated properties; and (20) the timing, amount and terms of capital available to us .

We caution you not to place undue reliance on these forward-looking statements, which speak only as of the date of this report, and we undertake no obligation to update such information.

GLOSSARY OF SELECTED PETROLEUM TERMS

The following abbreviations and definitions are terms commonly used in the oil and natural gas industry and throughout this Form 10-KSB:

“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.

“CO2.” Carbon dioxide, a gas that can be found in naturally occurring reservoirs, typically associated with ancient volcanoes, and also is a major byproduct from manufacturing and power production, also utilized in enhanced oil recovery through injection into an oil reservoir.

“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.

“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 gasoline’s 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 E&P 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 petroleum 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.” 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 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.

"proved undeveloped reserves." 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 a present value, discounted at 10% per annum, and is not necessarily the same as market value.

"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 reserves from a property, and is calculated in the same exact fashion as a PV-10 value, except that the projected revenue stream is adjusted to account for the estimated amount of federal income tax that must be paid.

"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.

PART I

ITEM 1. DESCRIPTION OF BUSINESS

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. "Old NGS" refers to Natural Gas Systems, Inc. (Delaware), a private Delaware corporation formed in 2003, which subsequently merged into NGS.

General

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. We currently own oil and gas properties in four crude oil and natural gas producing fields in the State of Louisiana, all of which are referred to as our Delhi Field or our Tullos Field (Area), and non producing leases in the Gulf Coast and Mid-continent regions of the United States.

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

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

document.

Our stock is traded on the American Stock Exchange 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, 2007, we had six full-time employees, not including contract personnel and outsourced service providers.

Corporate History of Reverse Merger

Reality Interactive, Inc. ("Reality"), a Nevada corporation that traded on the OTC Bulletin Board under the symbol RLYI.OB and the predecessor of Natural Gas Systems, Inc., now 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 SEC.

On May 26, 2004, Natural Gas Systems, Inc., a privately owned Delaware corporation formed in September 2003 ("Old NGS"), was 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 our Company, and the crude oil and natural gas business of Old NGS became that of our Company. Concurrently with the listing of our shares on the AMEX during July, 2006, Natural Gas Systems was renamed Evolution Petroleum Corporation to avoid confusion with similar names traded on the 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 us after the merger.

Business Activities

We are focused on an overall strategy of acquiring controlling working interests in oil and gas resources within established fields and redeveloping those fields through the application of capital and technology to convert the oil and gas resources into profitable producing reserves. Within this overall strategy, we have established three specific business initiatives:

I Enhanced oil recovery (EOR) Initiative, using miscible and immiscible gas flooding to extract tertiary resources;

II Bypassed Resource Initiative, using technology-based redevelopment of primary resources in mature oil and gas fields; and

III Unconventional Gas Resource Initiative, using modern stimulation and completion technologies to economically produce tight gas formations.

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. 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 gas price volatility;
- Reduced operational risks and costs associated with lower pressures and lower temperatures; and
- Control of operations, development timing and technology selection.

We purchased our first oil and gas property in September 2003 through the acquisition of all of the active working interests and the corresponding 80% net revenue interest in property and wells in the Delhi Field, located in northeastern Louisiana. This acquisition included the purchase of six producing wells, one salt water disposal well and 37 shut-in wells with minimal crude oil production per day and no natural gas sales. The Delhi Field encompasses approximately 13,636 acres, and the primary Paluxy and Tuscaloosa producing reservoirs in the field were unitized in the 1950's as the Delhi Holt Bryant Unit. Our acquisition included the Delhi Holt Bryant Unit and certain other depths, excluding a separate reservoir contained in the Mengel Unit in the Delhi Field. We conducted various development activities in the Delhi Field since the acquisition. Between January and July 2006, we also acquired royalty and overriding royalty interests in the Delhi Holt Bryant Unit aggregating approximately 7.4%.

In June 2006, we conveyed a farmout to a wholly owned subsidiary of Denbury Resources (**"Denbury"**) that included all of our working interests in the Delhi Holt Bryant Unit and 75% of our working interests in other depths of the Delhi Field, for which we received

approximately $50 million in cash, a 25% reversionary back-in working interest in the Delhi Holt Bryant Unit after payout, as defined in the agreement, and a commitment by Denbury to install a CO2 enhanced oil recovery project (**"CO2-EOR"**) in the Delhi Holt Bryant Unit (the **"Delhi Farmout"**). We also retained our separately acquired royalty and overriding royalty interests aggregating approximately 7.4% on the Delhi Holt Bryant Unit, including the CO2-EOR project.

In September 2004, we completed the acquisition of a 100% working interest and an approximate 78% average net revenue interest in producing crude oil wells, equipment and improvements located in the Tullos Urania, Colgrade and Crossroads Fields in LaSalle and Winn Parishes, Louisiana, which we refer to collectively as the "**Tullos Field Area**". The purchased assets included approximately 124 oil wells, 9 water disposal wells, and all associated infrastructure, including water disposal facilities, crude oil and water tanks, flow lines and pumping units. The purchase also included 15 wells without leases. We subsequently acquired new leases for ten of these wells.

In early February 2005, we completed the acquisition of a 100% working interest and an approximate 79% average net revenue interest in similar properties in our Tullos Field Area. The purchased assets included approximately 121 oil wells, 8 salt water disposal wells and associated infrastructure and equipment.

Since the acquisitions of the Tullos Field assets, we have conducted various development activities, primarily to improve operations, bring operations up to industry standards, and increase produced water disposal capacity.

During fiscal 2007, we initiated four projects within our Bypassed Resource Initiative and two projects within our Unconventional Gas Resource Initiative. To date, activity in these projects primarily has been the leasing of mineral rights in the state of Texas for our Bypassed Resource Initiative and in the Mid-Continent region for our Unconventional Gas Initiative.

For a more detailed discussion, please see "**Item 2. - Properties**."

Markets and Customers

To date all of our crude oil has been produced and sold from our Delhi Field and Tullos Field Areas in Louisiana. All of our natural gas has been produced and sold from our Delhi Field in Louisiana. Since June 2006, we are no longer the operator of the Delhi Field, due to our closing of the Delhi Farmout. Consequently, we had no natural gas or natural gas liquids production available to us for sales and marketing purposes during fiscal year 2007.

Marketing of crude oil and natural gas production 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 20 years, crude oil price fluctuations have been extremely volatile, with crude oil prices varying from less than $10.00 to in excess of $75 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 20 years, domestic natural gas prices have been 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 factors tend to influence product prices more for natural gas than for crude oil.

In the U.S. market where we operate, crude oil and gas liquids are readily transportable and marketable. Since March 2005, we have sold all of our operated crude oil production to Plains Marketing LP, a crude oil purchaser, at competitive field prices. A portion of our crude oil production has been subject to fixed price contracts (excluding basis risk) with Plains Marketing as described in the "Commodity Contracts" section below. We believe that other crude oil purchasers are readily available.

Prior to fiscal year 2007, we produced natural gas liquids from our Delhi Field, all of which we sold to Dufour Petroleum, L.P., a subsidiary of Enbridge Energy Partners, at a market competitive price based on an index price of liquid components, less a charge of $0.175 per gallon for transportation and fractionation.

With respect to natural gas sales, there is only one natural gas pipeline sales point readily available to the gas treating facility that had been serving our Delhi natural gas production. Although this could reduce our operator's leverage in negotiating favorable transportation charges and sales prices, we believe that any future natural gas sales would be inconsistent with the nature of the CO2-EOR project planned for the Delhi Holt Bryant Unit.

From March 2005 to the closing of the Delhi Farmout in June 2006, we sold all of our operated natural gas volumes through Texla Energy Management, Inc., a natural gas marketer/aggregator, although we believe that other natural gas marketers are readily available. A portion of our natural gas volumes had been sold under commodity contracts, as discussed in the section below. The remaining natural gas volumes were priced on either a monthly average index or a daily cash price as established at the Henry Hub market, less a $0.215 per MMBTU deduction for the market differential between Henry Hub and our sales point. All gas sold from the Delhi Field was charged $0.0854 per MMBTU by Gulf

South, the pipeline into which we deliver our gas, for transportation. These costs, along with the costs for natural gas processing and transportation prior to delivery to the sales point, were deducted from the natural gas sales receipts before calculation and distribution of royalties. Title to the natural gas passed to the purchaser at the metered interconnection to the transportation pipeline, where the Index price was reduced by the Gulf South transportation charge.

COMMODITY CONTRACTS

In compliance with the loan agreement we entered into with Prospect Energy in February 2005, we executed three commodity contracts for approximately 50% of the production volumes that our outside petroleum engineers estimated for our proved developed producing reserves on a rolling two year basis. Although we paid off the Prospect loan in May 2006, three of these contracts continued to be effective in fiscal 2006 and 2007, as described below.

The first commodity contract, with Plains Marketing L.P., covered the sale of 70 barrels of crude oil per day for a 12 month period from March 2005 through February 2006. The fixed sale price was based upon the NYMEX WTI (West Texas Intermediate) crude oil price and monthly settlements, wherein Plains Marketing delivered a fixed price of $48.35 per barrel to us before adjustment for the basis differential between the NYMEX price and the contract price. This contract was extended for the months of March 2006 through May 2006 at a fixed price of $52.55 per barrel of oil for 70 barrels of oil per day, extended for the three months of June 2006 through August 2006 at a fixed price of $63.45 per barrel of oil for 90 barrels of oil per day, and extended for the six months of September 2006 through February 2007 at a fixed price of $69.30 per barrel of oil for 90 barrels of oil per day. Plains Marketing L.P. is our crude oil purchaser and picks up our production in the field using their trucks.

The second commodity contract is between us and Wells Fargo Bank, N.A. We purchased a series of price floors, set at a NYMEX WTI price of $38.00 per barrel of crude oil, based upon the arithmetic average of the daily settlement price for the first nearby month of NYMEX WTI futures, for 2,000 barrels of crude oil per month for March 2006 through February 2007. The cost of the hedge was $3.00 per barrel of oil.

Our third commodity contract was with Texla Energy Management, Inc., whereby we sold 100 MMBTU per day at a fixed price of $6.21 per MMBTU over a fifteen month period beginning March 1, 2005 and ending May 31, 2006.The fixed price was before deduction of a $0.0854 per MMBTU fixed gathering charge by Gulf South, the owner of the natural gas pipeline into which we deliver our natural gas from the Delhi Field. This fixed price included the basis differential from NYMEX to our sales point on the Gulf South pipeline.

Since March 1, 2007, all of our oil production has been sold to Plains Marketing L.P. under a normal (thirty day "evergreen") sales contract.

COMPETITION

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 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 the ability to efficiently conduct operations, achieve technological advantages, identify and acquire suitable properties 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 to increase, including in the area of rapidly changing environmental laws and regulations. We also believe that our present operations substantially comply with applicable regulations. To date, such regulations have not had a material effect on our operations, or the costs thereof. 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.

Please see Item 2. Properties, Item 2. Subsequent Events and Item 3. Legal Proceedings).

ITEM 1A. RISK FACTORS

Risks related to the Company

OPERATING RESULTS FROM OIL AND GAS PRODUCTION MAY DECLINE.

Due to the Delhi Farmout we completed on June 12, 2006 with Denbury Onshore LLC (the “Delhi Farmout”), our future development initiatives in the Delhi Field are expected to be replaced with a CO2 enhanced oil recovery (“CO2-EOR”) project offering much greater potential, which Denbury has undertaken an obligation to fund and operate. As anticipated, the Delhi Farmout resulted in the reduction of net production and net revenues accruing to us from Delhi, until such time, if at all, as the CO2-EOR project is completed and brought online.

Without further acquisitions of new properties, production increases at our Tullos Field Area or any results from future drilling, our production and revenues from oil and gas operations may decline in the foreseeable future, as compared to our fiscal 2006 results.

THE TYPES OF RESOURCES WE FOCUS ON HAVE SUBSTANTIAL OPERATIONAL RISKS.

Our business plan focuses on the acquisition and development of relatively shallow, more complex and/or lower permeability reservoirs. Shallower reservoirs usually have lower pressure, which translates into fewer natural gas volumes in place; complex reservoirs are more difficult to analyze and exploit; and low permeability reservoirs require more wells and stimulation for development and such wells may have low profit margins and higher capital costs per produced BBL of oil or MCF of gas.

The Delhi Farmout EOR project requires significant amounts of CO2 resources, the source of which may be become unavailable or be curtailed. In order to produce and deliver sufficient quantities of CO2 from Denbury’s reserves from its Jackson Dome, Mississippi field, the construction of an approximately 100 mile pipeline necessary to connect to the Delhi Field will require large amounts of capital resources and the acquisition of new permits, right-of-ways, engineering designs, construction personnel and materials. Denbury’s failure to manage these and other technical, strategic and logistical risks may render ultimate enhanced recoveries from the planned CO2-EOR project, if any, to fall short of our expectations.

In addition, the mature fields we currently own and operate have well bores that were drilled as early as the 1920s. As such, they contain older down-hole equipment and casing that is more subject to failure than new equipment. The failure of such equipment or other subsurface failure can result in the complete loss of a well.

Our new projects require that we acquire new leases in and around established fields and drill and complete wells, some which may be horizontal, as well as negotiate the purchase of existing well bores and production equipment and install our proprietary artificial lift technology that has yet to be proven in the field. Leases may not be available, required oil field services may not be obtainable on the desired schedule or at the expected costs. While the projected drilling results are 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 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. Therefore, we face all the risks common to companies in their early stages 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 effect on us from the outcome of these types of uncertainty. Prior to our recent Delhi Farmout with Denbury, we have incurred significant losses since the inception of our oil and gas operations and we have since resumed incurring losses. We cannot assure you that we will be successful. While members of our management 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. Instead, 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.

REGULATORY AND ACCOUNTING REQUIREMENTS MAY REQUIRE SUBSTANTIAL REDUCTIONS IN REPORTED PROVEN RESERVES (SEE GLOSSARY) AND LIMITATIONS OF HEDGING.

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 these rules, 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 year and requires a write down 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.

In order to reduce our exposure to short-term fluctuations in the price of crude oil and natural gas and comply with the terms of our loan agreement with Prospect Energy, we entered into three commodity contracts. Although we terminated our loan agreement in May 2006, these contracts continued to be effective in our fiscal 2006 and 2007 years, all of which had expired by February 2007. Commodity contracts may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected, our customers fail to purchase contracted quantities of crude oil or natural gas or a sudden, unexpected event materially impacts crude oil prices. In addition, any future commodity contracts may limit the benefit to us of increases in the price of crude oil.

WE MAY BE UNABLE TO ACQUIRE AND DEVELOP THE ADDITIONAL OIL AND 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, our immediate future growth is highly dependent on our ability to develop additional oil and 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 always be the operator of some of our wells. 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 effect on our results of operations.

THE LOSS OF KEY PERSONNEL COULD ADVERSELY AFFECT US.

We depend to a large extent on the services of certain key management personnel, including our executive officers, the loss of any of whom could have a material adverse effect on our operations. In particular, our future success is dependent upon Robert S. Herlin, our 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..

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

WE MAY HAVE DIFFICULTY MANAGING FUTURE GROWTH AND THE RELATED DEMANDS ON OUR RESOURCES AND MAY HAVE DIFFICULTY IN ACHIEVING FUTURE GROWTH.

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

- our ability to identify and acquire new development or acquisition projects;
- our ability to develop existing properties;
- our ability to continue to retain and attract skilled personnel;
- the results of our development program and acquisition efforts;

- the success of our technologies;
- hydrocarbon prices;

- 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 CRUDE OIL AND NATURAL 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 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 reserves based on risk of recovery, and estimates of the future net cash flows expected therefrom prepared by different engineers or by the same engineers but at different times may vary substantially. Accordingly, reserve estimates may be subject to downward or upward adjustment. Actual production, revenue and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material. The information regarding discounted future net cash flows included in this report should not be considered as the current market value of the estimated crude oil and natural gas reserves attributable to our properties. 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 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. 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. 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. Our future drilling activities may not be successful and, if unsuccessful, such failure would have an adverse effect on our future results of operations and financial condition. We cannot assure you that our overall drilling success rate or our drilling success rate for activities within a particular geographic area will not decline. We may identify and develop prospects through a number of methods, some of which do not include lateral 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 may vary from our capital budget. The final determination with respect to the drilling of any scheduled or budgeted prospects will be dependent on a number of factors, including, but not limited to:

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

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, oil and gas prices do not move in tandem. Because approximately 63% of our reserves at July 1, 2007 are crude oil reserves, we are more affected by movements in crude oil prices. While our new projects are evaluated based on the assumption of oil and gas prices considerably less than in the current market or projected in the futures market, we do assume commodity prices will be higher than historic levels prior to 2004.

OILFIELD SERVICE PRICES HAVE BEEN ESCALATING, AND THE AVAILABILITY OF SUCH SERVICES MAY BE INADEQUATE TO MEET OUR NEEDS.

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

GOVERNMENT REGULATION AND LIABILITY FOR ENVIRONMENTAL MATTERS MAY ADVERSELY AFFECT OUR BUSINESS AND RESULTS OF OPERATIONS.

Crude oil and natural gas operations are subject to extensive federal, state and local government regulations, which may be changed from time to time. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of crude oil and natural gas wells below actual production capacity in order to conserve supplies of crude oil and natural gas. There are federal, state and local laws and regulations primarily relating to protection of human health and the environment applicable to the development, production, handling, storage, transportation and disposal of crude oil and natural gas, by-products thereof and other substances and materials produced or used in connection with crude oil and natural gas operations. In addition, we may inherit liability for environmental damages caused by previous owners of property we purchase or lease or nearby properties. As a result, we may incur substantial liabilities to third parties or governmental entities. We are also subject to changing and extensive tax laws, the effects of which cannot be predicted. The implementation of new, or the modification of existing, laws or regulations could have a material adverse effect on us.

Risks Associated with Our Stock

OUR STOCK PRICE HAS BEEN AND MAY CONTINUE TO BE VERY VOLATILE.

Our common stock is thinly traded and the market price has been, and is likely to continue to be, highly volatile. For example, during the year prior to June 30, 2007, our stock price as traded on the American Stock Exchange ranged from $2.38 to $3.66. 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.

The following share calculations treat shares issuable upon the exercise of options or warrants as outstanding (both in the numerator and denominator for percentages) and assume actual vesting.

Our executive officers and directors, in the aggregate, beneficially own approximately 11 million shares or approximately 38% of our outstanding common stock, inclusive of which our Chairman of the Board, Mr. Laird Q. Cagan, Managing Director of Cagan McAfee Capital Partners, LLC (“CMCP”) currently owns or controls, directly or indirectly, approximately 7.7 million shares, or approximately 29% of our outstanding common stock. Mr. Eric McAfee, a Managing Director of CMCP, currently owns or controls, directly or indirectly, approximately 5.1 million shares, or approximately 19% of our outstanding common stock, but is neither an officer nor a member of our board of directors. Collectively, the two managing directors of CMCP currently own or control, directly or indirectly, approximately 12.9 million shares, or approximately 47% of our outstanding common stock. As a result, these holders, if they were to act together, could exercise effective control over all 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 American Stock Exchange. In the year prior to June 30, 2007, the actual trading volume in our common stock ranged from a low of 1,200 shares of common stock traded to a high of 532,900 shares of common stock traded, with only 61 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 ANALYSTS 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 one non-company paid analyst and one company paid analyst 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 would likely 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 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 will 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 or liquidation;
- 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.

ITEM 2. DESCRIPTION OF PROPERTIES.

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, currently our most strategic asset, is in the early stages of being redeveloped by Denbury, as operator, through an enhanced oil recovery (EOR) project utilizing CO_2 technology:

- As of June 30, 2007, Denbury reported to us that approximately $27.75 million of capital has been charged to the project.
- On August 2, 2007, Denbury announced that the first leg of the Delhi CO_2 pipeline, from Jackson Dome to Tinsley Field, was 56% complete.
- Via public presentations, Denbury continues to state that first CO_2 injection at Delhi should occur in 2008 and that significant oil production from Delhi is projected for 2009.

We, and various other companies that submitted offers to participate with us, believe that the Delhi Holt Bryant Unit is an excellent candidate for a CO_2-EOR project due to its favorable rock characteristics, large unproven reserves remaining in place, miscibility potential, low cost of drilling to a relatively shallow depth and relatively close location to naturally occurring CO_2 reserves approximately 100 miles east of the Delhi Field. In June 2006, we conveyed a farmout to Denbury for all of our working interests in the Delhi Holt Bryant Unit and 75% of our working interests in certain other depths of the Delhi Field. For this, we received approximately $50 million in cash, a 25% back-in working interest in the Delhi Holt Bryant Unit and a commitment by Denbury Resources to install a CO_2-EOR project in the Delhi Holt Bryant Unit (the **"Delhi Farmout"**), while also retaining separately acquired royalty and overriding royalty interests aggregating 7.4% in the Holt Bryant Unit, as described in more detail below.

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 W. D. Von Gonten & Co., the third party reservoir engineering firm that prepares our independent estimate of proved reserves, the Delhi Field has produced more than 200 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 waterflood did not utilize a more traditional and effective five spot flood pattern that generally results in a more complete reservoir sweep and oil recovery.

At the time we began our oil and gas operations in late September 2003, we purchased 100% of the working interests and an 80% net revenue interest in the Delhi Field (from the surface to the top of the Massive Anhydride, 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 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 necessary to serve as our gas gathering line and placed a gas processing plant in the field, thus re-starting shut-in 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, were believed to be less than 50% depleted. Based on positive CO_2 pilots conducted by Sun Oil in 1985, and favorable rock characteristics shown in multiple cores taken throughout the Delhi Field, we began discussions in late 2004 with industry partners skilled in tertiary/EOR recovery methods, especially with respect to CO_2 injection.

With positive industry reception, and following extended negotiations with three candidate 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 (the "Delhi Farmout") to a subsidiary of Denbury. Important aspects of this transaction include:

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

- Denbury committed to install a CO_2-EOR project in the Holt Bryant Unit and is obligated to expend a minimum of $100 million on the project over the next 6-1/2 years, subject to penalty payments to us for shortfalls in such expenditures. All capital expenditures necessary to install the project are required to be borne by DNR.

- Denbury, the dominant CO_2-EOR operator on the Gulf Coast, currently operates several CO_2-EOR projects, and owns naturally occurring CO_2 reserves we believe to be sufficient to meet the needs of the Delhi project and which have been dedicated to the Delhi Project.

- We retained significant participating interests through separately acquired royalty and overriding royalty interests aggregating 7.4%, and a 25% back-in working interest (20% revenue interest). We expect the value of these interests will substantially exceed the $50 million cash component of the Delhi Farmout.

- Our 25% back-in working interest in the CO_2-EOR project is based on a defined $200 million threshold, and our back-in occurs when cumulative project net 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.

- We expect to be able to claim proven reserves following the first injection of CO_2 and demonstration of production response, projected to occur in 2009.

Bypassed Resource Property

Our Bypassed Resource 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.

Texas

Following the closing of our Delhi Farmout in June 2006, we began the process of identifying new Bypassed Resource Initiative projects. In selecting our four candidates:

- We leveraged our staff's extensive experience, gained over many years while employed at UPRC & Anadarko Petroleum, in the pioneering of horizontal drilling practices adapted to further develop and produce the Austin Chalk and Georgetown formations.

- We sought "flush production" projects that could provide substantial early revenues prior to peak production from the Delhi field.

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

Following project identification and economic analysis, we began leasing activities in December, 2006. Although leasing is far from complete, we had acquired 3,449 net acres as of June 30, 2007. Based on an independent reserve report from W.D. Von Gonten & Co. dated July 1, 2007, this leasing resulted in approximately:

- 1,272,000 proved undeveloped BOE

- 50% oil and 50% gas, and

- $25,715,000 of PV10.

Tullos Field Area

On September 3, 2004, through a wholly-owned subsidiary, we completed the acquisition of a 100% working interest and approximately 78% average net revenue interest in producing and shut-in crude oil wells, water disposal wells, equipment and improvements located in the Tullos Urania, Colgrade and Crossroads Fields in LaSalle and Winn Parish, Louisiana, collectively referred to as the Tullos Field Area. The purchased assets included 124 completed wells, 9 water disposal wells, and all associated infrastructure, including water disposal facilities, crude oil and water tanks, flow lines and pumping units. Fifteen of these crude oil wells required new leases. Of the purchased wells, 81 were producing and 43 were shut-in due to repair and maintenance requirements. The purchase price for the acquisition was $725,000 before adjustment for post-effective date production and expenses.

In early February 2005, we closed the purchase of a 100% working interest and approximately 79% average net revenue interest in additional properties in the same Tullos Urania and Colgrade Fields. The purchased assets included 65 producing crude oil wells, 56 shut-in crude oil wells, 8 salt water disposal wells and associated infrastructure and equipment. The purchase price for the acquisition was $798,907, after post-closing adjustments.

The original development plan for the properties included restoring wells to production and increases in produced water disposal capacity. Oil production from wells is generally in the form of fluid that is 99.5% brine water on average, and oil production rate is constrained by the capacity to properly dispose of the produced water. The high level of industry activity, however, has reduced the availability of oil field services, particularly workover rigs, and our wells require substantial ongoing maintenance and repairs that had been neglected in the year prior to the sale. Thus, the initial focus of operations was on restoring the stated production level of the then producing wells. We first applied to state regulatory agencies for required permits to convert wells to disposal use in 2005, and received the first permit in the spring of 2006. Following conversion, the state agencies must then authorize use of the converted well. The conversion process is ongoing and four disposal wells were completed in fiscal 2007.

We are reviewing the results of our development program and the ongoing high level of required maintenance and repairs to determine other options to maximize our value in the Tullos Field Area. In this regard, we have researched, analyzed and chosen a re-completion technique to increase the oil cut rate. In

March, 2007, we attempted to test an existing well bore, but were not able to make the re-completion due to the poor condition of the down-hole equipment. Lacking other candidates possessing the necessary well bore size needed to test the completion technology, we chose to drill a new well. This well has been drilled and completion operations are under way. If economically successful, we believe this technique could be applied to many other fields along the Gulf Coast with similar high water cut production characteristics.

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.

Following the closing of our Delhi Farmout in June 2006, we began the process of identifying Unconventional Natural Gas Resource Initiative projects. In choosing our two current candidates:

- We are leveraging our staff's expertise in horizontal drilling and tight gas development, a prerequisite to successfully exploiting and developing these resources;

- We focused on locations of source rock formations that are well known, especially shales and coals;

- We 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 future Delhi EOR and Bypassed Resource production; and

- We are adding additional natural gas exposure to our existing oil exposure.

We began actively acquiring leases for these two projects in May 2007. At June 30, 2007, we had acquired approximately 2,290 gross and 1,145 net acres across two projects, with active leasing still continuing.

Other Operations

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 and casualty 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 $1million.

Effective on March 1, 2007, we entered into a sublease agreement with Aspen Technology, Inc to rent approximately 8,400 square feet of Class "A" office space in the Westchase District area in West Houston. The terms of the lease are approximately nine years. Prior to that, we occupied a leased headquarters containing 2,259 square feet in a modern high-rise office building located in the West Memorial area of Houston, Texas. In April 2007, this lease expired. 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."

Significant Properties, Estimated Proved Oil and Gas Reserves, and Future Net Revenues

We engaged W. D. Von Gonten & Co. ("Von Gonten") to prepare an independent report of our proved reserves located in the Delhi Field, Texas properties and Tullos Field Area as of July 1, 2007. Von Gonten also previously prepared independent reports of our proved reserves at July 1, 2006, July 1, 2005, July 1, 2004 and January 1, 2004.

Estimates of reserve quantities and values must be viewed as being subject to significant change as more data about the properties becomes available. Many, if not most, of our existing wells are generally mature wells, originally drilled as early as the 1920's. As such, they contain older down-hole equipment and casing that is more subject to failure than new equipment. The failure of such equipment or other subsurface failure can result in the complete loss of a well.

At July 1, 2007, natural gas represented 37% and crude oil represented 63% of total proved reserves, denominated in equivalent barrels using a six MCF of gas to one barrel of oil conversion ratio, as compared to 1% and 99%, respectively, at July 1, 2006. The increase in proved reserves was mostly due to the proved undeveloped reserves we acquired through mineral leasing activities during the last half of fiscal 2007 and development opportunities identified in the Tullos Field Area.

The following table sets forth, as of July 1, 2007 and July 1, 2006, information regarding our proved reserves based on the assumptions set forth in Note 10 to the Consolidated Financial Statements, where additional reserve information is provided. The average NYMEX prices used to calculate estimated future net revenues were $70.68 and $73.93 per barrel of oil and $6.80 and $6.10 per MMBTU of gas as of June 30, 2007 and June 30, 2006, respectively. The average NYMEX prices used were adjusted for transportation, market differentials and BTU content of gas produced. Amounts do not include estimates of future Federal and State income taxes.

	Oil (bbls)	Gas (mcf)	Estimated Future Net Revenues	Estimated Future Net Revenues Discounted at 10%
July 1, 2007	1,084,000	3,838,000	$ 50,009,883	$ 33,327,359
July 1, 2006	460,525	25,800	$ 14,141,560	$ 8,038,791

At July 1, 2007, Proved Developed reserves (including Proved Developed non-producing) totaled 23% of Total Proved reserves, the balance consisting of Proved Undeveloped reserves.

At July 1, 2006, Proved Developed reserves totaled 82% of Total Proved reserves, the balance consisting of Proved Undeveloped reserves.

Production, Average Sales Prices and Average Production Costs

The following table set forth certain information regarding production volumes, oil and gas sales, average sales prices received and expenses for the periods indicated:

Product	Year ended June 30, 2007 Volume	Year ended June 30, 2007 Price	Year ended June 30, 2006 Volume	Year ended June 30, 2006 Price
Gas (Mcf)	—	—	44,745	$ 9.48
Oil (Bbls)	29,148	$ 64.05	42,869	$ 56.85

Average production costs, including production taxes, per unit of production (using a six to one conversion ratio of Mcf's to barrels) were approximately $49 and $35 per barrel of oil equivalent for the years ended June 30, 2007 and 2006, respectively.

Reduced volumes for the year ended June 30, 2007, as compared to the year ended June 30, 2006, were mostly attributable to the near term loss of our working interest in the Delhi Holt Bryant Unit, which is undergoing installation of a CO2-EOR operation. Under the June 2006 Delhi Farmout agreement, we retained separately acquired royalty and overriding royalty interests aggregating approximately 7.4% on all present and future

production in the Delhi Holt Bryant Unit, plus a 25% reversionary working interest after payout, as defined.

Productive Wells and Developed Acreage

Developed acreage at June 30, 2006 totaled 599 net and gross acres, all of which is in the Tullos Field Area in La Salle and Winn Parish Louisiana. This is a reduction from the beginning of the prior year by 13,636 acres, due to the Delhi Farmout, which became effective as of June 1, 2006.

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 Area. Approximately 75% of the shut-in crude oil wells in the Tullos Field Area are believed, in most part, to be capable of production following varying degrees of repair and maintenance or incremental water disposal capacity.

Undeveloped Acreage

As of June 30, 2007, we held approximately 19,572 gross and 8,003 net undeveloped acres in the Gulf Coast and Mid-Continent regions of the United States, as follows:

Region/Field	Gross Acreage	Net Acreage*
Mid-Continent	2,290	1,145
Gulf Coast	3,646	3,449
Gulf Coast, Delhi Field**	13,636	3,409
Total	19,572	8,003

*Of these acres, 31% or 2,494 net acres were proved.

** Includes from the surface of the Earth to the top of the Massive Anhydride, less and except the Delhi Holt Bryant CO2 and Mengel Units. With respect to the Delhi Holt Bryant Unit, currently scheduled for CO2-EOR operations within this same acreage, we currently hold royalty and overriding royalty interests aggregating approximately 7.4%, and a 25% working interest that will revert to us, as, if and when payout occurs, as defined. We are not the operator of the CO2-EOR project.

Drilling

During the year ended June 30, 2007, no new wells were drilled. During the year ended June 30, 2006, we drilled and completed 5 new development wells in the Delhi Field.

Subsequent Events

On August 3, 2007, we were advised of an oil spill in the Tullos Field near one of our leases. At the request of field agents of the Louisiana Department of Environmental Quality and the EPA, we agreed to commence a clean-up operation that was completed by the end of August 2007. A detailed analysis of the oil in the spill compared to our produced oil was conducted by an EPA approved laboratory. We believe that the various independent analyses show, supported by the formal findings of the laboratory, that the oil in the spill did not originate from our operations. We also believe that most of the estimated $600,000 of costs incurred in the cleanup, before adjustment following audit and negotiation of the billings, will be covered by insurance or reimbursement from the relevant government oil spill funds, but we can give no assurance that such reimbursement will occur. All clean up costs, net of any reimbursements, will be expensed as incurred.

In August 2007, the board of directors approved a resolution to issue a total of 125,000 shares of common stock options to three new employees as part of their total compensation for employment. The options are excisable at the closing price of the common stock on the date of issuance and vests in equal amounts quarterly over four years, subject to other standard terms and conditions as provided by the Company.

In September 2007, the board of directors approved a resolution to issue a total of 1,010,000 shares of common stock options to existing employees as part of their long term incentive compensation. The options are excisable at the closing price of the common stock on the date of issuance and vest in equal amounts quarterly over four years, subject to other standard terms and conditions as provided by the Company.

ITEM 3. LEGAL PROCEEDINGS.

On November 17, 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, our wholly owned subsidiaries, as working interest owners/operators of various oil and gas leases in the Delhi Field. Plaintiffs claim that the defendants' oil and gas exploration, development and production activities on their properties has caused soil and ground water contamination as a result of the release of hydrocarbons and drilling fluids. Plaintiffs seek damages for testing, clean-up and remediation of the properties as well as diminution in their value and mental anguish to the individual plaintiffs, unjust enrichment and punitive damages for alleged concealment of ongoing activities.

All defendants have filed exceptions to plaintiffs' suit alleging that it is premature, its allegations are vague and that administrative review

through the Louisiana Office of Conservation rather than legal action in the court is plaintiffs' proper remedy. These exceptions have not yet been heard by the court. Discovery has just begun and the allegations of plaintiffs' suit are so vague that the specifics of their claims cannot be determined yet with certainty.

Management intends to contest plaintiffs' claims vigorously. To this point, plaintiffs have not produced any evidence of specific damage to their lands by defendants' oil and gas operations. While the Delhi Field has been in production for over fifty years, NGS Sub Corp. and Arkla Petroleum LLC have only been the owner and operator for the period of time beginning 2003 and ending in 2006, and we believe that no contamination of significance occurred during our period of ownership. We believe that our liability exposure results largely through any potential contractual indemnity of prior working interest owners. Until such time as the specifics of plaintiffs' claims are identified through the discovery process, and particularly any evidence of actual contamination of soil or groundwater, the amount of any judgment that might be rendered cannot be determined with accuracy.

During the quarter ended June 2006, the Governor of the State of Louisiana signed into law new legislation addressing complaints similar to and including those filed against us. Although the intention of the legislation was designed to limit plaintiff complaints and remedies by possibly deferring first to administrative experts within the Louisiana State Departments of Environmental Quality and Natural Resources, it is unclear at this time the impact of such legislation.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

There were no matters submitted during the fourth quarter of the fiscal year covered by this report to a vote of security holders through the solicitation of proxies or otherwise.

PART II

ITEM 5. MARKET FOR COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND SMALL BUSINESS ISSUER PURCHASES OF EQUITY SECURITIES.

Common Stock

Our common stock is currently traded on the American Stock Exchange 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 following table shows, for each quarter of fiscal 2007 and 2006, the high and low closing sales prices as reported by the American Stock Exchange and the OTC Bulletin Board. The quotations from the OTC Bulletin Board represent inter-dealer prices, without retail mark-up, markdown or commissions, and may not represent actual transactions.

American Stock Exchange / OTC Bulletin Board

2007:	High	Low
Fourth quarter ended June 30, 2007	$ 3.66	$ 2.42
Third quarter ended March 31, 2007	$ 3.18	$ 2.49
Second quarter ended December 31, 2006	$ 3.04	$ 2.38
First quarter ended September 30, 2006	$ 3.30	$ 2.64

2006:	High	Low
Fourth quarter ended June 30, 2006	$ 3.70	$ 2.01
Third quarter ended March 31, 2006	$ 2.65	$ 1.31
Second quarter ended December 31, 2005	$ 2.05	$ 1.15
First quarter ended September 30, 2005	$ 2.05	$ 1.00

Holders

As of June 30, 2007, there were 26,776,234 shares of common stock issued and outstanding, held by approximately 182 holders of record.

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	3,223,242(1)	$ 1.50	1,286,758
Equity compensation plans not approved by security holders	1,453,021(2)	$ 1.51	—
Total	4,676,263	$ 1.50	1,286,758

(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 newly acquired subsidiary's 2003 Stock Option Plan. As of June 30, 2007, 510,000 shares remain issuable upon exercise under the 2003 Stock Option Plan and no further options shall be issued thereunder. As of June 30, 2007, there were 2,511,000 shares of common stock issued or issuable upon exercise of outstanding options and 202,242 shares issued directly under the 2004 Stock Plan, leaving 1,286,758 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 319,931 shares of common stock at an exercise price of $1.00, with a seven year term (warrants), of which 287,931 remain outstanding and un-exercised. Of these aforementioned warrants, 240,000 of these were issued to CMCP and their assigns in connection with arranging the merger, of which 215,000 remain outstanding and un-exercised and 79,931 were issued to Laird Q. Cagan, Chadbourn Securities and their assigns in connection with capital raising services, of which 72,931 remain outstanding and un-exercised. Subsequently, we issued warrants to purchase 122,590 shares of common stock to Laird Q. Cagan, Chadbourn Securities and their assigns in connection with capital raising services, a warrant to purchase 50,000 shares for capital raising services in connection with arranging our loan with Prospect Energy Corporation, of which 5,000 shares remain outstanding and un-exercised, 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 and a warrant to purchase 150,000 shares of common stock in connection with Sterling McDonald's annual performance incentives.

Recent Sales of Unregistered Securities

In November 2006, we made a direct stock grant for 50,000 shares to Liviakis Communications for investor relations services. In May 2007, we issued 16,987 shares of our common stock under a cashless exercise, thereby fully retiring a warrant to purchase 25,000 of our common shares at $1 per share. The shares issued during the period were exempted from registration in reliance upon Section 4(2) of the Securities Act of 1933, as amended, and Regulation D promulgated thereunder.

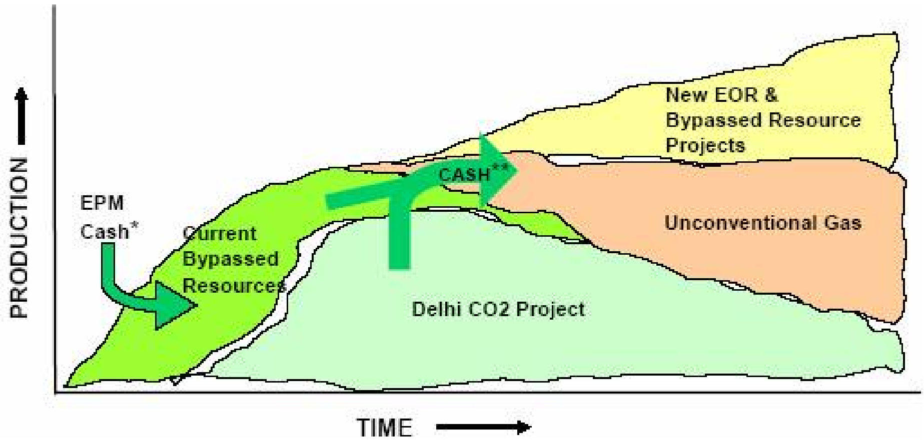
ITEM 6. MANAGEMENT'S DISCUSSION AND ANALYSIS OR PLAN OF OPERATION.

Oil & Gas Activities and Reserves

As previously reported, fiscal 2007 was expected to be a transitional year following the June 2006 closing of the farmout of our Delhi Holt Bryant Unit in the Delhi Field to install a CO2 enhanced oil recovery project (the "**Delhi Farmout**"). We understood that the Delhi Farmout would eliminate our revenues and net income from the Delhi Field producing wells until such time as the operator commenced EOR field production, most likely after mid-calendar 2008. We also projected that the interest income on the net cash proceeds from the Delhi Farmout would more than make up for this lost income, while also providing a funding source to accelerate the development of new project in our Bypassed Resource and Unconventional Gas Resource Initiatives. These expectations and projections were borne out during the fiscal year 2007.

Our ongoing strategic plan is to maximize shareholder value by utilizing our staff expertise and strong balance sheet to develop near term revenues through our Bypassed Resource projects and to seed our Unconventional Gas Resource projects through acreage acquisitions. Net cash flows from the Bypassed Resource projects and the Delhi Farmout then will be utilized to begin full development of our Unconventional Gas Resource projects, our new EOR projects and future growth.

<u>EPM Business Plan</u>
* Current cash resources feed Bypassed Resource Projects for near term revenues
** Cash generated from Bypassed Resource Projects and Delhi then feed pending projects in Unconventional Gas and EOR



Bypassed Resource Initiative:

As previously reported, we began leasing in December 2006 on four Bypassed Resource projects located in Texas. This initiative targets the leasing of specific well sites in order to access previously bypassed primary resources, in known productive fields, that we believe exhibit fairly predictable reserves and production. With this pursuit, we leverage our operating personnel's successful track record and knowledge of specific reservoirs, fields and horizontal drilling techniques. By the end of our fiscal year ended June 30, 2007, we had leased 3,646 gross and 3,449 net acres in these projects. Based on an independent reserve report from W.D. Von Gonten & Co. dated July 1, 2007, these leasing activities resulted in:

- The addition of approximately 1,272,000 BOE of Proved Undeveloped reserves.; and
- The addition of approximately $25,714,000 in PV-10, or $0.96 per outstanding common share.
- The addition of both natural gas and oil to our previous oil exposure.

Our fifth Bypassed Resource project is in our Louisiana Tullos Field Area, which also supplies all of our current production. Our plans for Tullos have been carried out in part through the conversion of five wells to salt water disposal and restarting production in numerous shut-in producer wells during fiscal 2007 and part of fiscal 2006. In March 2007, we attempted to test a new completion technique in an existing, inactive well bore, but were unsuccessful in making the re-completion due to the poor downhole condition of the well. Lacking other well bore candidates with the necessary size to test

the technology, we elected to drill a new well. This well was drilled in September 2007 and we anticipate that testing of the technology will extend to the end of calendar year 2007. If successful, we believe this technique could be applied to increase production in a large number of fields along the Gulf Coast that exhibit similar high water cut production and other reservoir characteristics.

Enhanced Oil Recovery (EOR) Initiative:

Our EOR projects target the use of miscible and immiscible gas flooding techniques, potentially combined with the completion technology developed in Tullos, to develop tertiary reserves from otherwise "depleted" oil fields. Our most substantial EOR asset is the Delhi Holt Bryant Unit CO2-EOR project, that continues to progress on schedule:

- As of June 30, 2007, Denbury reported to us that approximately $27.75 million of capital has been charged to the project.
- On August 2, 2007, Denbury announced that the first leg of the Delhi CO2 pipeline, from Jackson Dome to Tinsley Field, was 56% complete.
- Via public presentations, Denbury continues to state that first CO2 injection at Delhi should occur in 2008 and that significant oil production from Delhi is projected for 2009.

We view these as positive signs that our significant ownership interests in this project, including 7.4% in royalty and overriding royalty interests and a 25% back-in after payout, are moving closer to fruition.

Currently, we have begun early development work on our next EOR project.

Unconventional Gas Resource Initiative:

Subsequent to March 31, 2007, we began leasing on two Unconventional Natural Gas Resource projects. These projects are targeted at known reservoirs of "unconventional natural gas", meaning natural gas stored in "tight" formations. Our focus is on source rocks that have low permeability, repeatable similar drilling results and extend over large areas, such as shales and coals. Our operating staff's extensive experience in horizontal drilling and unconventional gas reservoirs is key, since horizontal drilling practices are generally required for positive economic results from these reservoirs.

These projects are expected to require substantial investments over a multiyear period beginning in late 2008. Consequently, these projects are a natural fit with our Bypassed Resource projects and the Delhi Farmout, in that we believe the Bypassed Resource projects should begin generating substantial free cash flows during the same time period as the Unconventional Gas investments are required. Increasing production from the Unconventional Gas projects should then be available to offset normal production declines from the Bypassed Resource projects currently under way.

By June 30, 2007, we had leased 3,646 gross and 3,449 net acres with additional leasing activity ongoing. Development of proved reserves will require additional investments in drilling of test wells and establishment of economic production in offsetting leases.

Refer to Item 2, "Properties", for further disclosures regarding reserve values and a more in-depth discussion of our properties.

Liquidity and Capital Resources

Our balance sheet remains strong with a large bank of working capital and no funded debt.

At June 30, 2007, we had approximately $27.3 million of positive working capital, as compared to $6.8 million of positive working capital at June 30, 2006. Our June 30, 2006 working capital excluded approximately $34.7 million of short-term investments in the QI account discussed below, and also excluded $12.4 million of deferred tax liabilities, both arising from the Delhi Farmout.

At June 30, 2007 our working capital (i) was free of all income tax liabilities arising from our Delhi Farmout, as these amounts were disbursed to taxing authorities during 2006 and 2007, (ii) exceeded our original expectations by approximately $1.1 million, in that our state of Louisiana income tax estimate was initially overstated for the gain from our Delhi Farmout, and (iii) contained more than adequate funds to seed and carry out, in part, the balance of the five Initiative II Bypassed Resource projects and two Initiative III Unconventional Gas Resource projects now in process.

Virtually all of the $27.7 million of cash balances held in our working capital at June 30, 2007 was, and continues to be, invested in a U.S. Government Money Market Fund holding investments exclusively in short-term U.S. Government Agency securities or short-term repurchase agreements secured by U.S. Government Agency securities. None of our funds have had exposure to securities associated with collateralized mortgage, debt or loan obligations (CMO, CDO or CLOs), extendible commercial paper, secured liquidity notes or similar securities.

Of the $35 million we placed in a qualified intermediary (**"QI"**) account for possible Internal Revenue Code 1031 "like-kind exchanges"(from the $50 million of proceeds we received from the Delhi Farmout in June 2006), we completed $0.58 million of like kind exchanges during

fiscal 2006 and 2007. In accordance with IRC 1031 regulations, we withdrew the balance of approximately $35.3 million, including approximately $0.85 million in interest earned, on December 9, 2007. An unintended benefit we received from the establishment of the QI account was a resulting installment sale for tax purposes, which delayed the payment of our estimated deposits, thus earning us additional investment income.

Cash flow used by our operating activities for the year ended June 30, 2007 was $14.5 million, of which $15.1 million was used to pay our income taxes payable, including $421,325 of overpaid tax deposits. This compares to cash flow used by operating activities of $0.7 million for the year ended June 30, 2006.

Cash flow provided by investing activities was approximately $32.4 million for the year ended June 30, 2007, mostly due to $34.7 million that was provided from the QI account. This was offset by approximately $2.3 million of capital expenditures we invested in oil and gas properties. Of this amount, approximately $1.9 million was used to research title and to pay lease bonuses to acquire acreage for four Bypassed Resource and two Unconventional Gas Resource programs currently in process. The remaining $0.4 million was used to further develop our oil and gas properties in the Tullos Field. For the comparable year ended June 30, 2006, $11.8 million was provided by investing activities, mostly due to the $50 million provided from the Delhi Farmout sale, offset by $34.7 million used to set up the QI account.

We expect our capital expenditures will increase substantially during fiscal year 2008, due to continued leasing and the execution of a development drilling program within our Bypassed Resource Initiative, and continued leasing in our Unconventional Gas Initiative. Based on our current plans, we expect capital expenditures to exceed $15 million during fiscal 2008, with half or more dedicated to development drilling.

During the year ended June 30, 2007, we neither used nor provided funds through financing transactions, except for the $15,532 we used for transaction costs related to prior period financing transactions. During the year ended June 30, 2006, $1.04 million was provided to us through borrowings, and $1.0 million in proceeds (net of transaction costs) was provided to us from the sale of 351,335 shares of our common stock and the issuance of warrants to Prospect for their additional loan. Funds used in financing activities included the repayment of all of our debt in the amount of $5.6 million during the year ended June 30, 2006, resulting in a net use of funds for financing transactions of $3.7 million.

Results of Operations

Summary

As previously disclosed, at this stage of our development our objectives are to:

- Continue increasing our intrinsic net asset value per share,
- Build the infrastructure necessary to carry our many development projects, while reducing our cash burn rate,
- Begin to convert our non-producing assets to producing assets through the drill bit, and
- Continue managing our cash burn rate, and begin generating earnings per share.

We believe considerable progress has been made in these metrics. Since our inception in late 2003, we have funded our operations with $8.4 million of total cash equity invested (excluding $1.3 million of accounting value assigned to warrants issued to a lender) against 26.8 million shares currently outstanding. By June 30, 2007, we had converted this equity into: (i) $28 million of cash held on a debt free balance sheet, (ii) 1,724,000 BOE of proved reserves, and (iii) a 7.4% overriding royalty and 25% reversionary back-in interest in a major CO2 EOR project in the Delhi Field that, if successful, would generate far greater value per share.

On the second and third metrics, we have added highly experienced technical and administrative staff that will allow us to begin active drilling operations within our development projects. In October 2006, we hired a General Manager of Horizontal Drilling and Unconventional Development as part of our key management team. He brings valued experience in drilling over 800 wells, over 200 of which being horizontal wells. In January 2007, we hired our first Landman who has over 25 year's of related experience. Subsequent to the close of our current fiscal year, we further hired a Manager of Land Administration to organize and maintain our land records and interface them with our accounting records in our outsourced Excalibur ERP system. Additional infrastructure has been added subsequent to fiscal year end, and we are actively recruiting additional support personnel to aid in our projected drilling activity.

On the last metric, of the $1.81 million earnings loss incurred during the current fiscal year, $1.61 million was due to non-cash stock compensation expense, which significantly increased by our required adoption of SFAS 123 (R). When combined with other non-cash charges presented in our Statement of Cash Flows, this left us slightly positive in cash flow generated from our operations, before changes in assets and liabilities. With respect to future earnings per share, we expect to make positive progress as we begin converting our relatively low earning cash assets into production from our proved undeveloped reserves, beginning with the drilling of our first proved undeveloped location in late calendar 2007.

Year Ended June 30, 2007 vs. June 30, 2006

For the year ended June 30, 2007 we reported a net loss available to common shareholders of $1.8 million, or $0.07 per share basic and diluted, and for the year ended June 30, 2006 we reported net income available to common shareholders of $25.7 million or $1.03 per share basic, and $1.01 per share diluted.

A major contributor to our fiscal year 2007 loss was a $1.6 million charge to non-cash stock compensation expense. This expense was driven much higher, mostly by our required adoption of FAS 123(R) in the current year, as compared to the $.55 million we charged to non-cash stock compensation expense under APB 25 during fiscal year 2006. In our fiscal year 2007, we also lost our Delhi production due to the Delhi Farmout we completed in June 2006. The lost production was much more than offset by the $1.9 million of interest income we recorded in fiscal year 2007. This compared to $0.2 million of interest income recorded during fiscal 2006.

Oil and Gas Revenues. Total revenues were $1.9 million in fiscal year 2007, compared to total revenues of $2.9 million in fiscal year 2006. This 35% decrease in total revenues was primarily due to the loss of oil and gas sales from the Delhi Field as a result of the Delhi Farmout last year. Offsetting this was higher average realized oil prices in 2007 versus 2006, or approximately $64 versus $55 per BOE, respectively.

Lease Operating Expenses. Lease operating expenses include costs incurred to operate and maintain wells and related equipment. Lease operating expenses for the years ended June 30, 2007 and 2006 was $1.4 million and $1.7 million, respectively. The 21% decrease in our lease operating expenses is primarily due to the Delhi Farmout from last year. However, the Tullos Field area incurred higher than anticipated expenses in fiscal 2007 due to overall cost increases for goods and services, unexpected casing leaks in numerous saltwater disposal wells, and other non-recurring operating events.

Production taxes. The 28% decrease in production (severance) taxes is directly related to the reduction of volumes produced and sold as a result of the Delhi Farmout in prior year.

Franchise taxes. Approximately $108,000 of State of Louisiana franchise taxes was expensed and paid in fiscal year 2007.

General and Administrative expenses (G&A). General and administrative expenses are overhead-related expenses, including among others, wages and benefits, stock-based compensation, legal and accounting fees, insurance, and investor relations expenses. General and administrative expenses for the years ended June 30, 2007 and 2006 were $4.4 million and $2.8 million, respectively. This 55% increase in G&A expenses is primarily related to incremental higher non-cash stock-based compensation expense of $1 million in fiscal 2007 compared to fiscal 2006, and $0.5 million in other compensation related costs, including the addition of one employee, annual bonus payouts, new 401-K plan and related taxes. Our G&A expenses continue to increase due to costs of being a public company compounded by high recruitment costs, salaries and benefits necessary to attract and retain personnel in a tight labor market for skilled energy staff professionals.

Depletion, Depreciation and Amortization (DD&A). DD&A expenses for the years ended June 30, 2007 and 2006 was $0.3 million and $0.4 million, respectively. This 29% decrease in DD&A expense is due to fewer volumes recorded as a result of the Delhi Farmout from last year. The average DDA rate per BOE increased 34% to $9.99 per barrel of oil equivalent, compared to prior year of $7.48 per barrel of oil equivalent. This increase is mostly attributable to the addition of proved reserves in our Texas Bypassed Resource properties at approximately $13.80/BOE and, to a lesser extent, to higher capital spending than estimated for our Tullos Field Area during fiscal year 2007. Depreciation of office equipment and computer equipment is computed on a straight line basis.

Interest Income. Our interest income increased significantly in fiscal 2007 from fiscal 2006, or to $1.9 million from $0.2 million. This is primarily due to higher cash available to the Company due to the proceeds received from the Delhi Farmout and slightly higher interest rate yields in fiscal 2007 on our money market investments.

Interest Expense. Interest expense decreased to $0 in fiscal 2007, compared to $2.6 million in fiscal 2006. We were debt free in fiscal 2007 and continue to be in fiscal 2008.

Critical Accounting Policies and Estimates

Accounting for Oil and Gas Property Costs. As more fully discussed in Note 2 to the consolidated financial statements (i) we follow the full cost method of accounting for the costs of our oil and gas properties in accordance with SEC Rule 4-10 of Regulation SX, (ii) we amortize such costs using the units of production method, and (iii) we apply a quarterly full cost ceiling test. Adverse changes in operating conditions (primarily oil or gas price declines) could result in permanent write-downs in the carrying value of oil and gas properties as well as non-cash charges to operations, but would not affect cash flows. At June 30, 2007, the measure to calculate our ceiling test was approximately $23.7 million, thereby exceeding the carrying value of our oil and gas properties by approximately $18.3 million, or 343%. At that date, a 10% decrease in product price assumptions would reduce our ceiling test cushion by approximately $3.1 million.

Proved Oil and Gas Reserves are also subject to estimates. An independent petroleum engineer annually estimates 100% of our proved reserves. Reserve engineering is a subjective process that is dependent upon the quality of available data and the interpretation thereof. In addition, subsequent physical and economic factors such as the results of drilling, testing, production and product prices may justify revision of such estimates. Therefore, actual quantities, production timing, and the value of reserves may differ substantially from estimates. A reduction in proved reserves would result in an increase in depreciation, depletion and amortization ("DD&A") expense and could result in permanent write-downs in the carrying value of our oil and gas properties resulting in non-cash charges to operations, but would not affect our cash flows. Since July 1, 2005, we have experienced cumulative upward reserve estimate revisions totaling 95,662 BOE, or 11% on beginning reserves of 893,904 BOE, or 6% on ending reserves of 1,723,667 BOE.

Stock Based Compensation. Effective July 1, 2006, we adopted Statement of Financial Accounting Standards ("SFAS") No. 123(R), "Accounting for Share-Based Payment," as amended, 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 has not been rendered that was outstanding as of July 1, 2006. For periods prior to July 1, 2006, we applied to our stock-based compensation awards the intrinsic method of accounting as set forth in Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations.

New Accounting Pronouncements. During February 2007, the Financial Accounting Standards Board ("FASB") issued FASB Statement of Accounting Standards ("SFAS") No 159, "The Fair Value Option for Financial Assets and Financial Liabilities" ("SFAS No. 159") which

permits all entities to choose, at specified election dates, to measure eligible items at fair value. SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value, and thereby mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. This Statement also establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 is effective as of the beginning of an entity's first fiscal year that begins after November 15, 2007. We are evaluating the impact that this Statement will have on our financial statements.

In September 2006, the Financial Accounting Standards Board ("FASB") issued FASB Statement of Accounting Standards ("SFAS") No. 157. This Statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, and expands disclosures about fair value measurements. This Statement applies under other accounting pronouncements that require or permit fair value measurements, where fair value has been determined to be the relevant measurement attribute. This statement is effective for fiscal years beginning after November 15, 2007. We are evaluating the impact that this Statement will have on our financial statements.

In June 2006, the FASB issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes-an Interpretation of FASB Statement No. 109," ("FIN 48") which provides guidance for the recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 requires the evaluation of a tax position as a two-step process. First, we will be required to determine whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. If the tax position meets the "more likely than not" recognition threshold, it is then measured and recorded at the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. We will be required to adopt FIN 48 in the first quarter of fiscal year 2008. We are evaluating our tax positions and the impact that this guidance will have on our financial statements.

ITEM 7. FINANCIAL STATEMENTS

Index to Consolidated Financial Statements

Evolution Petroleum Corporation and Subsidiaries
Consolidated Balance Sheets

	June 30, 2007	June 30, 2006 (as restated - see note 3)
Assets		
Current Assets:		
Cash and cash equivalents	$ 27,746,942	$ 9,893,547
Accounts receivable, trade	212,585	132,371
Income tax receivable	421,325	—
Inventories	274,813	76,917

Prepaid expenses	159,228	157,629
Retainers and deposits	106,625	60,895
Total current assets	28,921,518	10,321,359
Cash in qualified intermediary account for "like-kind" exchanges	—	34,662,368
Oil & Gas properties - full cost	4,187,440	3,878,551
Oil & Gas properties - not being amortized	1,924,552	52,098
Less: accumulated depletion	(652,439)	(371,624)
Net oil & gas properties	5,459,553	3,559,025
Furniture, fixtures and equipment, at cost	173,205	16,561
Less: accumulated depreciation	(18,333)	(7,998)
Net furniture, fixtures, and equipment	154,872	8,563
Restricted deposits	—	326,835
Other assets	370,049	79,808
Total assets	$ 34,905,992	$ 48,957,958
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$ 993,894	$ 310,272
Accrued liabilities	595,833	473,782
Income taxes payable	—	2,645,619
Royalties payable	6,831	47,054
Total current liabilities	1,596,558	3,476,727
Long term liabilities:		
Deferred tax liability	338,001	12,362,156
Deferred rent payable	47,289	—
Asset retirement obligations	140,998	123,679
Total liabilities	2,122,846	15,962,562
Common Stock, totaling 351,335 shares subject to demand registration rights	—	790,500
Stockholders' equity:		
Common Stock, par value $0.001 per share; 100,000,000 shares authorized, 26,776,234 and 26,300,670 issued and outstanding as of June 30, 2007 and June 30, 2006, respectively, net of 351,335 shares of common stock subject to demand registration rights at June 30, 2006.	26,776	26,300
Additional paid-in capital	12,443,199	10,274,555
Deferred stock compensation	(45,826)	(265,167)
Retained earnings	20,358,997	22,169,208
Total stockholders' equity	32,783,146	32,204,896
Total liabilities and stockholders' equity	$ 34,905,992	$ 48,957,958

See accompanying notes to consolidated financial statements.

Evolution Petroleum Corporation and Subsidiaries
Consolidated Statements of Operations

	Year Ended June 30,	
	2007	2006 (as restated - see note 3)
Revenues:		
Oil sales	$ 1,866,892	$ 2,450,676
Gas sales	—	424,190
Price risk management activities	(14)	(13,452)
Total revenues	1,866,878	2,861,414
Operating expenses:		
Production expenses	1,370,226	1,725,760
Production taxes	62,426	86,562
Franchise taxes	107,754	—
Depreciation, depletion and amortization	291,150	407,467
General and administrative (includes stock-based compensation of $1,613,493 and $546,597, respectively for June 30, 2007 and 2006)	4,383,846	2,826,085
Total operating expenses	6,215,402	5,045,874
Loss from operations	(4,348,524)	(2,184,460)
Other income (expense):		

Interest income	1,920,913	165,313
Interest expense	—	(2,600,180)
Gain (loss) on sale of assets	(21,453)	45,325,468
Total other income (expense)	1,899,460	42,890,601
Income (loss) before income taxes	(2,449,064)	40,706,141
Income tax expense:		
Current	11,407,202	2,645,619
Deferred	(12,046,055)	12,362,156
Total income tax expense	(638,853)	15,007,775
Net income (loss)	$ (1,810,211)	$ 25,698,366
Earnings (loss) per common share		
Basic	$ (0.07)	$ 1.03
Diluted	$ (0.07)	$ 1.01
Weighted average number of common share		
Basic	26,706,713	25,031,125
Diluted	26,706,713	25,555,992

See accompanying notes to consolidated financial statements.

Evolution Petroleum Corporation and Subsidiaries
Consolidated Statements of Cash Flow

	Year Ended June 30, 2007	2006 (as restated - see note 3)
Cash flows from operating activities		
Net Income (loss)	$ (1,810,211)	$ 25,698,366
Adjustments to reconcile net income (loss) to net cash used in operating activities:		
Gain on asset sale	—	(45,208,532)
Depletion	280,815	402,870
Depreciation	10,335	4,597
Stock-based compensation	1,613,493	546,567
Accretion of asset retirement obligations	17,319	27,716
Income tax liability	(12,024,155)	12,362,156
Deferred rent	47,289	—
Amortization of deferred financing costs	—	293,797
Accretion of debt discount and non-cash loan costs	—	1,739,046
Non-cash penalty expense	—	240,000
Changes in operating assets and liabilities:		
Accounts receivable	(80,214)	168,390
Income tax receivable	(421,325)	—
Retainer and deposits	(45,730)	(4,560)
Inventories	(197,896)	145,553
Prepaid expenses	(1,599)	(73,325)
Accounts payable	683,622	69,883
Royalties payable	(40,223)	(42,659)
Accrued liabilities	122,051	247,312
Income taxes	(2,645,619)	2,645,619
Net cash used in operating activities	(14,492,048)	(737,204)
Cash flows from investing activities		
Development of oil and gas properties	(417,964)	(2,611,369)
Acquisitions of oil and gas properties	(1,918,757)	(1,448,239)
Proceeds from asset sale	155,378	49,993,134
Capital expenditures for furniture, fixtures and equipment	(156,644)	(4,448)
Cash in qualified intermediary account for “like-kind” exchanges	34,662,368	(34,662,368)
Restricted deposits	326,835	536,254
Other assets	(290,241)	19,661
Net cash provided by investing activities	32,360,975	11,822,625
Cash flows from financing activities		
Payments on notes payable	—	(5,634,654)
Proceeds from notes payable	—	1,040,764
Deferred financing costs	—	(37,201)
Proceeds from issuance of common stock and fair value of warrants issued with debt	125	999,385
Transaction and registration costs	(15,657)	(108,856)
Net cash used in financing activities	(15,532)	(3,740,562)
Net increase in cash and cash equivalents	17,853,395	7,344,859

Cash and cash equivalents, beginning of period		9,893,547		2,548,688
Cash and cash equivalents, end of period	$	27,746,942	$	9,893,547
Supplemental disclosure of cash flow information:				
Interest paid	$	—	$	567,273
Income taxes paid	$	14,560,000	$	—
Non-cash transactions:				
Non-cash equity adjustment	$	790,500	$	50,000
Assumption of asset retirement obligations	$	—	$	—

See accompanying notes to the consolidated financial statements.

Evolution Petroleum Corporation and Subsidiaries
Consolidated Statements of Changes in Stockholders' Equity
For the Years ended June 30, 2007 and 2006

	Shares	Dollars	Additional Paid-in Capital	Deferred Stock Compensation	Retained Earnings (deficit)	Total Stockholders' Equity
Balance, June 30, 2005	24,774,606	$ 24,774	$ 9,611,767	$ (595,283)	$ (3,529,158)	$ 5,512,100
Sales and issuances of common stock	599,335	599	1,005,073	—	—	1,005,672
Reduction of capital related to common stock, subject to demand registration rights	(351,335)	(351)	(790,149)	—	—	(790,500)
Exercise of warrants	1,278,064	1,278	—	—	—	1,278
Fair value of warrants issued with debt	—	—	209,236	—	—	209,236
Transaction and Registration Costs	—	—	238,628	—	—	238,628
Stock-based compensation	—	—	—	330,116	—	330,116
Net income	—	—	—	—	25,698,366	25,698,366
Balance, June 30, 2006	26,300,670	$ 26,300	$ 10,274,555	$ (265,167)	$ 22,169,208	$ 32,204,896
Issuance of common stock	124,229	125	—	—	—	125
Reclassify temporary equity from prior year	351,335	351	790,149	—	—	790,500
Transaction and Registration Costs	—	—	(15,657)	—	—	(15,657)
Stock-based compensation	—	—	1,394,152	219,341	—	1,613,493
Net loss	—	—	—	—	(1,810,211)	(1,810,211)
Balance, June 30, 2007	26,776,234	$ 26,776	$ 12,443,199	$ (45,826)	$ 20,358,997	$ 32,783,146

See accompanying notes to consolidated financial statements.

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Basis of Preparation

Headquartered in Houston, Texas, Evolution Petroleum Corporation, formerly Natural Gas Systems, Inc. (the "Company", "EPM", "we" or "us"), is a petroleum company incorporated under the laws of the State of Nevada, engaged primarily in the acquisition, exploitation and development of properties for the production of crude oil and natural gas. We acquire established oil and gas properties and exploit them through the application of conventional and specialized technology to increase production, ultimate recoveries, or both.

Our stock is traded on the American Stock Exchange (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. Concurrently with the listing of our shares on the AMEX during July, 2006, we changed our name from Natural Gas Systems, Inc. to Evolution Petroleum Corporation to avoid confusion with similar names traded on the AMEX and to better reflect our business model.

At June 30, 2007, we conducted operations through our 100% working interests in our Tullos Field Area and our non-operated interests in our Delhi Field, all located onshore in Louisiana. Our Tullos Field Area consists of approximately 156 producing wells out of 260 well bores across 599 acres of high water cut primary reserve production, which we believe may be a candidate for redevelopment using modern technology. Our non-operated interests in the 13,636 acre Delhi Field consist of a 7.4% overriding and mineral royalty interest in the Delhi Holt Bryant Unit, a 25% reversionary working interest in the Delhi Holt Bryant Unit, and a 25% working interest in certain other depths in the Delhi Field. Our Delhi Holt Bryant Unit is scheduled for redevelopment using CO_2 enhanced oil recovery technology.

The consolidated financial statements herein have been prepared in accordance with generally accepted accounting principles (GAAP) and include the accounts of Evolution Petroleum Corporation and its subsidiaries, all of which are wholly owned. All inter-company transactions are eliminated upon consolidation. Certain prior year amounts have been reclassified to conform to the current year presentation.

2. Summary of Significant Accounting Policies

Use of Estimates — The preparation of financial statements in accordance with generally accepted accounting principles and pursuant to the rules and regulations of the Securities and Exchange Commission ("SEC") requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and disclosure of contingent assets and liabilities in the financial statements, including the significant use of estimates for oil and gas reserve information and the valuation allowance for deferred income taxes. Actual results could differ from those estimates.

Cash and Cash Equivalents — Cash and cash equivalents primarily consist of cash on deposit and investments in money market funds with original maturities of three months or less, stated at market value.

Oil and Gas Properties — We follow the full cost method of accounting for our investments in oil and natural gas properties. All costs incurred in the acquisition, exploration and development of oil and natural gas properties, including unproductive wells, are capitalized. Proceeds from the sale of oil and natural gas properties are credited to the full cost pool, unless the sale involves a significant quantity of reserves, in which case a gain or loss is recognized. Under the rules of the Securities and Exchange Commission ("SEC") for the full cost method of accounting, the net carrying value of oil and natural gas properties is limited to the sum of the present value (10% discount rate) of the estimated future net cash flows from proved reserves (net of estimated future expenditures to be incurred in developing and producing the proved reserves) based on current prices as of the balance sheet date, and excluding future cash outflows associated with settling asset retirement obligations, plus the lower of cost or estimated fair market value of unproved properties adjusted for related income tax effects. For the years ended June 30, 2007 and 2006, there was no impairment.

Capitalized costs of proved oil and natural gas properties are depleted on a unit of production method using proved oil and natural gas reserves. Costs depleted include net capitalized costs subject to depletion and estimated future dismantlement, restoration and abandonment costs.

The costs of certain unevaluated leasehold acreage and wells being drilled are not being amortized. Costs not being amortized are periodically assessed for possible impairments or reductions in value. If a reduction of value has occurred, the amount of the impairment is transferred to costs being amortized.

Furniture and Fixtures — Furniture and fixtures consist of office furniture, computer hardware and software and leasehold improvements. Depreciation of furniture and fixtures is computed using the straight-line method over their estimated useful lives, which vary from three to seven years.

Concentrations of Credit Risk — Financial instruments which potentially expose us to concentrations of credit risk consist primarily of trade accounts receivable. Our customer base is highly concentrated, even though our oil and gas products are highly marketable. Although we are directly affected by the well-being of the oil and gas industry, management does not believe a significant credit risk exists at June 30, 2007.

Revenue Recognition — We recognize oil and natural gas revenues 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. Through June 30, 2007, there were no product imbalances, as we owned and operated 100% of our natural gas properties.

Accounts Receivable, trade — Accounts receivable, trade consists of uncollateralized accrued oil and gas revenues due under normal trade terms, generally requiring payment within 30 days of production. Management reviews receivables periodically and reduces the carrying amount by a valuation allowance that reflects management's best estimate of the amount that may not be collectible. As of June 30, 2007 and 2006, the valuation allowance was $0.

Inventory — Inventory includes tubular goods and other lease and well equipment which we plan to utilize in our ongoing development activities and is generally carried at the lower of cost or market using the specific identification method.

Stock-based Compensation — Effective July 1, 2006, we adopted Statement of Financial Accounting Standards ("SFAS") No. 123(R), "Accounting for Share-Based Payment," as amended, 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 has not been rendered as of July 1, 2006. During the fiscal years ended June 30, 2007 and 2006, we recognized aggregate compensation expense of $1.5 million and $0.5 million, respectively, related to outstanding common stock options. During the fiscal years ended June 30, 2007 and 2006, we recognized aggregate compensation expense of approximately $95,000 and $40,000, respectively, related to outstanding restricted stock grants.

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

Accounting for Price Risk Management activities — We enter into certain financial derivative contracts utilized for non-trading purposes to minimize the impact of market price fluctuations on contractual commitments and forecasted transactions related to our oil and gas production. We follow the provisions of the Statement of Financial Accounting Standards ("SFAS") No. 133, Accounting for Derivative Instruments and Hedging Activities, for the accounting of our hedge transactions. SFAS No. 133 establishes accounting and reporting standards requiring that all derivatives instruments be recorded in the consolidated balance sheet as either an asset or a liability measured at fair value and requires that the changes in the fair value be recognized currently in earnings unless specific hedge accounting criteria is met. In accordance with this specific criteria, we did not elect to document and designate certain over-the-counter contracts we entered into to hedge the cash flow of part of our forecasted sale of oil and gas production.. Thus, the changes in the fair value of these over-the-counter contracts are reflected in earnings in the period in which they occur.

Income taxes — Income taxes are provided for the tax effects of transactions reported in the financial statements and consist of taxes currently due, if any, plus net deferred taxes related primarily to differences between the basis of assets and liabilities for financial and income tax reporting. Deferred tax assets and liabilities represent the future tax return consequences of those differences, which will either be taxable or deductible when the assets and liabilities are recovered or settled. Deferred tax assets include recognition of operating losses that are available to offset future taxable income and tax credits that are available to offset future income taxes. Valuation allowances are recognized to limit recognition of deferred tax assets where appropriate. Such allowances may be reversed when circumstances provide evidence that the deferred tax assets will more likely than not be realized.

Earnings (loss) per share — Basic and diluted earning per share calculations are presented in accordance with FASB 128, and are calculated on the basis of the weighted average number of common shares outstanding during the year. They include the dilutive effect of common stock equivalents in years with net income

New Accounting Pronouncements — During February 2007, the Financial Accounting Standards Board ("FASB") issued FASB Statement of Accounting Standards ("SFAS") No 159, "The Fair Value Option for Financial Assets and Financial Liabilities" ("SFAS No. 159") which permits all entities to choose, at specified election dates, to measure eligible items at fair value. SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value, and thereby mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. This Statement also establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 is effective as of the beginning of an entity's first fiscal year that begins after November 15, 2007. We are evaluating the impact that this Statement will have on our financial statements.

During September 2006, the Financial Accounting Standards Board ("FASB") issued FASB Statement of Accounting Standards ("SFAS") No. 157. This Statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, and expands disclosures about fair value measurements. This Statement applies under other accounting pronouncements that require or permit fair value measurements, where fair value has been determined to be the relevant measurement attribute. This statement is effective for fiscal years beginning after November 15, 2007. We are evaluating the impact that this Statement will have on our financial statements.

In June 2006, the FASB issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes-an Interpretation of FASB Statement No. 109," ("FIN 48") which provides guidance for the recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 requires the evaluation of a tax position as a two-step process. First, we will be required to determine whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. If the tax position meets the "more likely than not" recognition threshold, it is then measured and recorded at the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. We will be required to adopt FIN 48 in the first quarter of fiscal year 2008. We are evaluating our tax positions and the impact that this guidance will have on our financial statements.

3. Restatement of prior year financial statements

The financial statements for the year ended June 30, 2006 have been restated due to an error in the tax provision calculations. Income tax expense and income tax payable were restated, resulting in additional net income and reduced income taxes payable of approximately $1,072,000.

	Year Ended June 30, 2006 (as previously reported)	Year Ended June 30, 2006 (as restated)	Restated Difference
Balance Sheet:			
Assets	$ 48,957,958	$ 48,957,958	$ —
Liabilities	17,034,787	15,962,562	(1,072,225)
Temporary equity	790,500	790,500	—
Stockholders' equity	31,132,671	32,204,896	1,072,225
Income Statement:			
Pre-tax Income	40,706,141	40,706,141	—
Income tax expense	16,080,000	15,007,775	(1,072,225)
Net income	$ 24,626,141	$ 25,698,366	$ 1,072,225

4. Acquisitions and Divestitures

During the year ended June 30, 2007, we incurred $597,433 in lease bonuses related to our oil and gas acreage leasing activity, most of which was incurred in the latter half of the fiscal year. Of this amount, $478,147 was incurred on our Initiative II Bypassed Resource plays in Texas, and $119,286 was incurred for our Initiative III Unconventional Gas Resource plays in the Mid-Continent Region.

On July 21, 2006, we closed the acquisition of 0.39% in additional mineral royalty and overriding royalty interests in the Delhi Holt Bryant Unit, within the Delhi Field in North Louisiana, for $85,000 in cash consideration.

On September 20, 2006, we closed the purchase of a small parcel of land in Tullos, Louisiana, for $11,910, which will be used as a field yard to store tangible lease and wellhead equipment for our Tullos Field Area operations.

The funds used to acquire both of these properties were funded with monies set aside in our qualified intermediary (**QI**) bank account. The QI account provides us the opportunity to defer the recognition of taxable gain on amounts used from the QI account to acquire like-kind property within 180 days from the date of the outgoing property sale from our Delhi Farmout in exchange for assets identified within 45 days of such sale pursuant to Internal Revenue Code Section 1031.

On September 28, 2006, we completed the sale of two producing wells to the State of Louisiana that were located on a state highway expansion project being constructed through the Tullos Urania Field. We received net consideration of approximately $155,000.

In fiscal year 2006, we acquired royalty and overriding royalty interests totaling approximately 7% in the Delhi Holt Bryant Unit ("Delhi Unit") within the Delhi Field, for $1,464,000 of cash consideration, $420,000 of which came from the QI account.

5. Asset Retirement Obligations

Asset retirement obligations are included in long term liabilities on our balance sheet. The following table describes the changes in our asset retirement obligations for the period from June 30, 2006 to June 30, 2007:

Asset retirement obligation at June 30, 2006	$ 123,679
Liabilities incurred	—
Accretion expense for 2007	17,319
Revisions to estimates	—
Asset retirement obligation at June 30, 2007	$ 140,998

6. Oil and Gas Properties

As of June 30, 2007 and 2006, oil and gas properties not subject to amortization totaled $1,924,552 and $52,098, respectively. The significant increase in current year unamortized costs primarily consists of leaseholds acquired through a current and ongoing leasing program the Company started in December 2006. These costs are reviewed quarterly to determine when they should be transferred to the full cost pool and amortized.

7. Stock-Based Compensation

Effective July 1, 2006, we adopted the fair value recognition provisions of Statement of Financial Accounting Standard 123(R) "*Share-Based Payment*" ("SFAS 123(R)") using the modified prospective transition method. In addition, the Securities and Exchange Commission issued Staff Accounting Bulletin No. 107 "*Share-Based Payment*" ("SAB 107") in March 2005, which provides supplemental SFAS 123(R) application guidance based on the views of the SEC. Under the modified prospective transition method, compensation cost recognized in the fiscal year ended June 30, 2007 includes: (a) compensation cost for all share-based payments granted prior to, but not yet vested as of July 1, 2006, based on the grant date fair value estimated in accordance with the original provisions of SFAS No. 123, and (b) compensation cost for all share-based payments granted beginning July 1, 2006, based on the grant date fair value estimated in accordance with the provisions of SFAS 123(R). In accordance with the modified prospective transition method, results for prior periods have not been restated.

The adoption of SFAS 123(R) resulted in stock compensation expense for the fiscal year ended June 30, 2007 of approximately $1.6 million. This additional share-based compensation expense increased basic and diluted loss per share by $0.06 for the fiscal year ended June 30, 2007. For the fiscal year ended June 30, 2007, we did not recognize a tax benefit related to stock compensation expense because we believe it is more likely than not that the related deferred tax assets, which have been reduced by a full valuation allowance, will not be realized.

We use the Black-Scholes option-pricing model to estimate option fair values. The option-pricing model requires a number of assumptions, of which the most significant are, expected stock price volatility, the expected pre-vesting forfeiture rate and the expected option term (the amount of time from the grant date until the options are exercised or expire

For periods prior to July 1, 2006, we applied the intrinsic method to our stock-based compensation awards to our employees and directors as set forth in Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. Under these principles, no compensation expense for stock options granted to employees is reflected in net income as long as the stock options have an exercise price at least equal to the quoted market price of the underlying common stock on the date of grant.

Pro Forma Stock Compensation Expense for the fiscal year ended June 30, 2006

The following table illustrates the effect on net earnings per share if we had applied the fair value recognition provisions of SFAS 123(R) to stock-based employee compensation for the year ended June 30, 2006:

Net income attributable to common stockholders, as reported	$	25,698,366
Plus: share based compensation expense determined under APB 25		171,537
Less: compensation expense determined under Fair Value Method		(1,543,690)
Pro forma net income attributable to common stockholders	$	24,326,213
Basic earnings per common share:		
As reported	$	1.03
Pro Forma	$	0.97
Diluted earnings per common share:		
As reported	$	1.01
Pro Forma	$	0.95

The fair values of options and warrants granted during the years ended June 30, 2007 and 2006 were estimated at the date of grant using the Black-Scholes options pricing model assuming no dividends and with the following weighted average assumptions:

	Year ended June 30, 2007	Year ended June 30, 2006
Risk-free rate	4.8%	4.2% - 4.9%
Expected term (in years)	6.25	2 -4
Weighted-average volatility	163%	104% - 159%

Volatilities are based on the historical volatility of our closing common stock price. Expected term of options and warrants granted represents the period of time that options and warrants granted are expected to be outstanding. The risk-free rate for periods within the contractual life of the options and warrants is based on the comparable U.S. Treasury rates in effect at the time of each grant. The weighted average grant-date fair value of options granted during the years ended June 30, 2007 and 2006 was $2.71 and $1.31, respectively. There were no employee options or warrants exercised for the fiscal years ended June 30, 2007 and 2006.

Stock Options and Warrants

For the year ended June 30, 2007, we issued 150,000 stock options to an employee as part of their compensation for employment. The options were granted at the market price on the date of grant, and vests over four years. For the year ended June 30, 2007, no warrants were granted and no options or warrants have been exercised, canceled or forfeited. As of June 30, 2007, we had 1,037,500 of warrants outstanding to officers of the Company issued outside of the 2003 Stock Option Plan and the 2004 Stock Plan, exclusive of warrants for capital raising services.

The following table sets forth the stock option and warrant transactions for the year ended June 30, 2007:

	Number of Options/Warrants	Weighted Average Grant Price	Aggregate Intrinsic Value (1)	Weighted Average Remaining Contractual Term (in years)
Options and warrants outstanding at July 1, 2006	3,798,500	$ 1.49		
Granted	150,000	$ 2.71		
Exercised	0			
Canceled, forfeited, or expired	0			
Options and warrants outstanding at June 30, 2007	3,948,500	$ 1.54	$ 5,979,325	7.8
Options and warrants exercisable at June 30, 2007	2,386,625	$ 1.37	$ 4,013,059	7.7

(1) Based upon the difference between the market price of our common stock on the last trading date of the fiscal year and the option or warrant exercise price of in-the-money stock options or warrants.

A summary of the status of our non-vested options and warrants as of June 30, 2007, and the changes during the year ended June 30, 2007, is presented below:

	Number of Options and Warrants	Weighted Average Grant-Date Fair Value
Non-vested at July 1, 2006	2,335,532	$ 1.66
Granted	150,000	$ 2.61
Vested	(923,657)	
Canceled, forfeited, or expired	0	
Non-vested at June 30, 2007	1,561,875	$ 1.51

At June 30, 2007, unrecognized stock-based compensation expense related to non-vested stock option and warrant grants totaled approximately $2.2 million. This unrecognized expense will be amortized on a straight-line basis per grant over a weighted average remaining life of approximately 2.1 years.

Restricted Stock

For the year ended June 30, 2007, we issued a total of 57,242 shares of common stock pursuant to the stock grants described in the next paragraph. We recognized compensation expense over the vesting period of these shares. During the year ended June 30, 2007, we recognized aggregate compensation expense of $94,633 related to these outstanding restricted stock grants.

On October 5, 2006, we granted 20,000 shares of restricted stock with a grant date fair value of $2.71 per share to a new employee as a sign on bonus. On December 14, 2006, we granted a total of 37,242 shares (or 12,414 shares to each of our three independent outside directors) of restricted stock with a weighted average grant date fair value $2.90 per share. Such restricted stock grants vest over a one-year period. Each of the above restricted stock grants is subject to forfeiture, and cannot be sold, transferred or disposed of during the restriction period. We recognize compensation expense over the vesting period of these shares.

The following table sets forth the restricted stock transactions for the year ended June 30, 2007:

	Number of Restricted Shares	Weighted Average Grant-Date Fair Value
Outstanding at July 1, 2006	25,000	$ 1.61
Granted (1)	57,242	$ 2.83
Vested	(44,310)	
Canceled, forfeited, or expired	0	
Outstanding at end of period	37,932	$ 2.85

(1) The weighted average grant date fair value of restricted stock granted for the year ended June 30, 2007 was $2.83. The weighted average grant date fair value of restricted stock granted for the year ended June 30, 2006 was $1.61.

At June 30, 2007, unrecognized stock compensation expense related to restricted stock totaled approximately $68,000. Such unrecognized expense will be recognized as vesting occurs over a weighted average period of 0.5 years.

8. Common Stock, Stock Options and Warrants

Common Stock

During the year ended June 30, 2007, we reclassified $790,500 from temporary to permanent equity as discussed in the Registration Rights section below.

During the quarter ended March 31, 2007, we issued 20,000 shares of common stock to an employee as part of an incentive compensation package for employment. Also, three outside directors each received 12,414 shares of restricted common stock as part of a revised compensation plan for directors. All issuances of common stock are subject to vesting terms per individual stock agreements.

During the quarter ended December, 31, 2006, we entered into an amended consulting agreement whereby the consultant continues to provide investor relations services. For this, the Company agreed to issue to the consultant 50,000 shares of common stock, which is subject to monthly vesting, over a twelve month period. The effective date of the agreement is November 1, 2006.

During the year ended June 30, 2006, we raised gross proceeds of $790,500 from the sale of our common stock in a private equity offering and $209,235 from the issuance of warrants to Prospect Energy Corporation (Prospect) with respect to their additional loan. A total of 351,335 shares were sold at a price of $2.25 per share. We paid Chadbourn Securities and Laird Q. Cagan, a placement agent fee consisting of (i) cash equal to 8% of the gross proceeds, or $63,240 and (ii) warrants exercisable for up to 14,054 shares of our common stock at an exercise price of $2.25 per share.

As part of the repayment of the Prospect loan, Prospect demanded payment of an additional 100,000 warrants exercisable at a price of $2.71 per share. While we disagreed with the justification for the demand, we elected to issue the warrants. Since Prospect elected to immediately exercise the warrants, the impact of the issuance of the disputed warrants was negligible.

During the fiscal year 2006, we issued an aggregate 88,000 shares of common stock to individual consultants for services rendered; issued 160,000 shares of common stock to Rubicon Master Fund as compensation for not securing an effective registration on previously issued shares per the agreement; and lastly, various holders exercised their warrants into 1,278,064 shares of common stock.

Options and Warrants issued to Employees and Directors

2003 Stock Option Plan

Old NGS adopted a stock option plan in 2003 (the “2003 Plan”). The purpose of the 2003 Plan was to offer selected individuals an opportunity to acquire a proprietary interest in the success of Old NGS, or to increase such interest, by purchasing shares of the Old NGS common stock. The 2003 Plan provided both for the direct award or sale of shares and for the grant of options to purchase shares in an aggregate amount not to exceed 4,000,000 shares. Options granted under the Plan included non-statutory options as well as incentive stock options intended to qualify under Section 422 of the Internal Revenue Code. Of the options to purchase 600,000 shares granted under the 2003 Plan by Old NGS, all were assumed by Reality Interactive, Inc., predecessor to the Company. Of these, options to purchase 250,000 shares were granted to each of Messrs. Herlin and McDonald. These options were accounted for under APB 25.

2004 Stock Plan

On August 3, 2004, we adopted our 2004 Stock Plan (the “2004 Plan”). The purpose of the 2004 Plan is to offer selected individuals an opportunity to acquire a proprietary interest in our success, or to increase such interest, by purchasing our shares of common stock. The 2004 Plan provides both for the direct award or sale of shares and for the grant of options or warrants to purchase shares in an aggregate amount not to exceed 4,000,000 shares. Options granted under the 2004 Plan may include non-statutory options as well as incentive stock options intended to qualify under Section 422 of the Internal Revenue Code.

During the twelve month ended June 30, 2007, the company awarded a stock option to purchase 150,000 shares of common stock upon exercise of outstanding option under the 2004 Stock Plan to an employee, subject to vesting requirements per the agreement, and direct stock grants in the amount of 57,242 to our outside directors and an employee, leaving 1,286,758 shares of common stock available for issuance under the 2004 Stock Plan. See footnote 18 Subsequent events for additional stock options granted after the fiscal year ending June 30, 2007.

During the year ended June 30, 2006, the company awarded stock options to purchase 761,000 shares of common stock upon exercise of outstanding options under the 2004 Stock Plan to employees and directors, all subject to various vesting requirements, leaving 1,494,000 shares of common stock available for issuance under the 2004 Stock Plan, after taking into account awards to non-employees totaling 50,000 shares.

Non-Plan Warrants to Employees

No warrants were issued to employees during the fiscal year ended June 30, 2007.

During the year ended June 30, 2006, as part of their annual incentive compensation and in lieu of cash bonuses, Mr. Herlin was awarded warrants to purchase 400,000 shares of common stock, 150,000 of which were immediately vested in lieu of a cash bonus and 250,000 of which vest over four years, and Mr. McDonald was awarded warrants to purchase 150,000 shares, 100,000 of which were immediately vested in lieu of a cash bonus and 50,000 of which vest over four years. These warrants were granted at “at the money” on the grant date and have a contractual life of 10 years.

Options, Warrants and Grants to Non-Employees

At June 30, 2007, outstanding warrants and options, excluding employees, to purchase the Company’s common shares were as follows:

Warrants and Stock Options Outstanding (excludes employees)		
Range of	**Outstanding at**	**Exercisable at**

Holders	Exercisable Prices				June 30, 2007	June 30, 2007
Cagan McAfee Capital Partners, LLC	$	1.00	$	1.00	165,000	165,000
Chadbourn Securities, Inc.	$	1.50	$	2.50	9,463	9,463
Laird Q. Cagan	$	1.00	$	2.50	171,308	171,308
Steven D. Lee	$	0.001	$	1.80	110,000	110,000
Others	$	1.00	$	2.00	69,750	69,750
Total					525,521	525,521

During fiscal year ended June 30, 2007, the Company made a direct stock grant for 50,000 shares to Liviakis Communications for another year of investor relations services. Also, 25,000 warrants were cashless exercised in May 2007 resulting in 16,987 shares of common stock issued.

During fiscal year ended June 30, 2006, we issued warrants to purchase 14,054 shares of common stock in connection with capital raising services to Laird Q. Cagan and Chadbourn Securities, Inc., and a stock option to purchase 50,000 shares to Steve D. Lee under the 2004 Stock

Plan. Mr. Lee's grant gave rise to $39,275 of share based compensation expense under SFAS 123, to be spread over a six month vesting term, beginning March 2006. Fair value was derived using the Black-Scholes model using the following assumptions: Volatility - 150%, Risk Free Rate - 4.50%, Estimated Term - 1 year, and Dividends - 0.

In addition, the Company also made direct stock grants for 78,000 shares to Liviakis Communications for investor relations services and a direct stock grant for 10,000 shares to a third party consultant for services rendered. (Both grants are excluded from the table above) The Liviakis stock grant gave rise to $204,282 of expense, spread over a six month vesting schedule, beginning monthly in May 2006, and the consultant stock grant gives rise to $12,091 of immediate expense. The fair value of both direct stock grants under SFAS 123 was equivalent to the fair value of our stock on the date of grants.

During the fiscal year ended 2006, 1,864,500 warrants were (cashless) exercised resulting in 1,278,064 shares of common stock issued

Registration Rights

Under the terms of a private placement of 351,335 shares of our common stock, which we closed on June 10, 2006, the stock subscription agreement was subject to a registration rights agreement requiring us to use our reasonable efforts to register the stock subsequent to the demand of 40% of the holders of such stock. Such demand could not become effective, however, until the price of our common stock exceeded at least $14.23 per share, (approximately 6.3 times the subscription price). There were no specified damages for our failure to register, nor a specified timetable for obtaining such registration, except that the registration was to be undertaken by us as soon as practicable and was to stay effective for 120 days, or if such registration statement was on Form S-3 and provided for sales of securities from time to time pursuant to Rule 415 under the Securities Act, for up to one year. Until the demand registration right terminated, SEC rules required us to classify the proceeds as "temporary equity",until such time as the registration rights had terminated. We believe the demand registration rights terminated as of June 10, 2007, as all holders were able to freely sell their shares under Rule 144. Consequently, we reclassified the shares from temporary equity to permanent equity on our balance sheet at June 30, 2007.

Under the terms of a private placement of 1,200,000 shares of our common stock with the Rubicon Fund on May 6, 2005, we contemporaneously entered into a registration rights agreement (the "RRA"). The RRA required us, among other things, to obtain and maintain an effective registration statement with the SEC for Rubicon's shares, failing which, would have subjected us to the payment of penalties not to exceed 1% of the share proceeds, or $30,000, for each month of non-compliance. Penalties were to be incurred for each month for which a registration statement had not become effective, beginning October 6, 2005. Penalties were also to be incurred for any month for which effectiveness has not been maintained prior to the shares becoming tradable under Rule 144, but in no event would total penalties cumulatively exceed 8% or $240,000. In January 2006, we entered into a mutual agreement with Rubicon that eliminated their demand registration rights and any penalties, historic and future, in exchange for 160,000 shares of common stock.

We have also entered into registration rights agreements with others, the effect of which gives the holders the right to "piggyback" their shares, from time to time, as we register other shares. Alternatively, we may be required to register shares on Form S-3 under certain conditions.

9. Related Party Transactions

Laird Q. Cagan, the Chairman of our Board of Directors, is a Managing Director of Cagan McAfee Capital Partners, LLC ("CMCP"). CMCP performs financial advisory services for us pursuant to a written agreement and is paid a monthly retainer of $5,000 per month. In addition, Mr. Cagan is a registered representative of Chadbourn Securities, Inc. ("Chadbourn"), our non-exclusive placement agent for private financings. Pursuant to the Agreement between Mr. Cagan, Chadbourn and us, as amended, we pay a cash fee equal to 8% of the first $1 million of gross equity proceeds and declining by 1% for each subsequent $1million of gross proceeds to a minimum rate of 4%, and warrants equal to 4% of the shares placed by CMCP. No further financings are currently contemplated through Chadbourn Securities.

During the fiscal year ended June 30, 2007, we expensed and paid CMCP $60,000 in monthly retainers.

During fiscal year ended June 30, 2006, we expensed and paid CMCP $95,000 for monthly retainers, issued warrants to purchase 14,054 shares of common stock to Laird Q. Cagan and Chadbourn Securities, Inc. and paid a $63,240 cash commission to Chadbourn in connection with capital raising services (a portion of which Mr. Cagan receives). Also, in March 2006 Mr. Cagan loaned us $250,000, pursuant to a secured promissory note bearing interest at 10% per annum, for general working capital purposes. On June 13, 2006, we repaid the loan in full including accrued interest, or $257,058.

10. Supplemental Disclosures about Oil and Gas Producing Properties (unaudited)

Net Capitalized Costs

Evaluated and unevaluated capitalized costs related to our oil and gas producing activities are summarized as follows:

	Year Ended June 30, 2007	Year Ended June 30, 2006
Capitalized costs - Full Cost	$ 4,187,440	$ 3,878,551
Capitalized costs - Non-Amortizing	1,924,552	52,098
Total	6,111,992	3,930,649
Less accumulated depletion	(652,439)	(371,624)
Net capitalized costs	$ 5,459,553	$ 3,559,025

Unproved properties not subject to amortization at June 30, 2007 consisted of mainly leasehold acreage leased and related Landman broker costs incurred through our current leasing program. These costs are expected to be evaluated within the next two years.

Costs Incurred in Oil and Gas Acquisition, Exploration and Development

Costs incurred in oil and gas property acquisition, exploration and development activities which have been capitalized are summarized as follows:

	Year Ended June 30, 2007	Year Ended June 30, 2006
Property acquisition costs:		
Proved	$ 725,884	$ 1,448,239
Unproved	1,192,873	(9,788)
Exploration costs	—	—
Development costs	417,964	2,283,517
Total	$ 2,336,721	$ 3,721,968

Results of Operations from Oil and Gas Producing Activities (unaudited)

Our results of operations from oil and gas producing activities are presented below for fiscal years 2007 and 2006. The following table includes revenues and expenses associated directly with our oil and gas producing activities. It does not include any interest costs or general and administrative costs and, therefore, is not necessarily indicative of the contribution to consolidated net operating results of our oil and gas operations.

	Year Ended June 30, 2007	Year Ended June 30, 2006
Oil and gas sales	$ 1,866,878	$ 2,861,414
Production expenses	(1,370,226)	(1,725,760)
Production taxes	(62,426)	(86,562)
Depletion expense	(280,815)	(402,870)
Results of operations for oil and gas producing activities (excluding corporate overhead and financing costs)	$ 153,411	$ 646,222

Oil and Gas Reserve Quantities (unaudited)

The following table sets forth the net proved reserves of the Company as of July 1, 2007, and the changes therein for the periods from July 1, 2005 to July 1, 2007. The reserve information was prepared by W. D. Von Gonten & Co., independent petroleum engineers. All of the Company's oil and gas producing activities are located in the United States.

	Oil (bbls)	Gas (mcf)
Balance, July 1, 2005	771,883	732,123
Purchases of minerals in place	4,200	25,800
Extensions and discoveries	—	—

Revisions	138,762	—
Production	(46,942)	(45,368)
Sales of minerals in place	(407,403)	(686,755)
Balance, July 1, 2006 (1)	460,500	25,800
Purchases of minerals in place	—	—
Extensions and discoveries	694,300	3,838,000
Revisions	(38,800)	(25,800)
Production	(28,800)	—
Sales of minerals in place	(3,200)	—

Balance, July 1, 2007 (2)	1,084,000	3,838,000
Proved developed reserves:		
July 1, 2005	540,360	396,600
July 1, 2006	460,500	25,800
July 1, 2007	389,700	—

(1) During fiscal 2006, our proved reserves were reduced by the Delhi Farmout, offset by an increase in proved reserves in the Tullos Field Area due to the increase in commodity prices and additional proved developed non-producing reserves associated with shut-in wells.

(2) During fiscal 2007, we added 1.333,967 BOE of proved reserve extensions and discoveries. Of these, 95%, or approximately 1.27 million BOE, were acquired through leasing activities in our four Texas Bypassed Resource projects, requiring an estimated $18.1 million of additional capital expenditures to convert these proved reserves to proved developed reserves.

Standardized Measure of Discounted Future Net Cash Flows at June 30, 2007 and June 30, 2006 (unaudited)

The information that follows has been developed pursuant to SFAS No. 69 and utilizes reserve and production data prepared by independent petroleum consultants. Reserve estimates are inherently imprecise and estimates of new discoveries are less precise than those of producing oil and natural gas properties. Accordingly, these estimates are expected to change as future information becomes available.

The estimated discounted future net cash flows from estimated proved reserves are based on prices and costs as of the date of the estimate unless such prices or costs are contractually determined at such date. Actual future prices and costs may be materially higher or lower. Actual future net revenues also will be affected by factors such as actual production, supply and demand for oil and natural gas, curtailments or increases in consumption by natural gas purchasers, changes in governmental regulations or taxation and the impact of inflation on costs. Future income tax expense has been reduced for the effect of available net operating loss carryforwards.

	Year Ended June 30, 2007	Year Ended June 30, 2006
Future cash inflows	$ 97,669,992	$ 32,874,568
Future production costs	(29,044,113)	(18,167,012)
Future development costs	(18,616,000)	(566,000)
Future income taxes	(17,012,000)	(2,687,000)
Future net cash flows	$ 32,997,879	$ 11,454,556
10% annual discount	(11,007,581)	(4,943,196)
Standardized Measure	$ 21,990,298	$ 6,511,360

Changes in Standardized Measure

The following table sets forth the changes in standardized measure of discounted future net cash flows for the period from the years ended June 30, 2007 and 2006:

	Year Ended June 30, 2007	Year Ended June 30, 2006
Standardized Measure, beginning balance	$ 6,511,360	$ 13,241,078
Net changes in income taxes	(9,547,068)	1,445,256
Oil and gas sales, net of costs	(434,226)	(1,049,092)
Discoveries, extensions and transfers	43,710,638	239,382
Purchase of minerals in place	—	354,679
Sale of minerals in place	(178,245)	(12,916,340)
Changes in prices and costs	254,874	1,403,539
Change in development costs	(16,050,414)	1,116,590
Previously estimated development costs incurred during the period	86,000	—
Accretion discount	651,136	1,324,108
Revisions of estimates and other	(3,013,757)	1,352,160
Standardized Measure, ending balance	$ 21,990,298	$ 6,511,360

11. Restricted Deposits

During fiscal 2007, all prior year restricted deposits totaling $326,835 had been reclassified to either cash or other assets. In October 2006, we redeemed a certificate of deposit for $25,000 that was originally pledged to the State of Louisiana for future plugging and abandonment liability for part of the Delhi field. In August 2007, we received official release of our liability from the State of Louisiana for the Site Specific Trust Account, again for future plugging and abandonment liability for the Delhi field; therefore, our originally pledged certificate of deposit for $301,835 became an un-restricted asset to the Company. Due to a maturity date beyond one year, we reclassified this item as Other assets on our balance sheet.

In December 2006, due to the expiration of the like-kind exchange period, approximately $35 million was transferred from the qualified intermediary account to the Money Market Fund.

At June 30, 2006, restricted deposits totaled $326,835, representing an increase of $25,000 and a decrease of approximately $560,000 from prior fiscal year end. The increase was for a certificate of deposit pledged to the State of Louisiana for future plugging and abandonment requirements for five new wells drilled as part of the Development Drilling program in Delhi field. The decrease was the result of early loan repayment of the Prospect Facility in May 2006. Pursuant to the terms of our Delhi Farmout arrangement, as soon as the State of Louisiana processes the change of operator to Denbury Onshore, LLC and Denbury funds the Site Specific Trust Account accordingly, we will be refunded the full balance of $326,835. Approximately $226,835 exceeds FDIC insurance limits in depository accounts at Wells Fargo bank.

Also, at June 30, 2006, we had approximately $34.7 million (which is available to us at any time) held in the qualified intermediary account as discussed in note 12 below. These funds were invested in a U.S. Government Money Market Fund with short-term durations.

12. Income Taxes

The tax effect of significant temporary differences representing deferred tax assets and liabilities at June 30, 2007 and 2006 are as follows:

	Year ended 2007	Year ended 2006
Oil & gas properties	$ (516,000)	$ (198,000)
Basis in subsidiary stock	149,000	149,000
Other	193,000	88,000
Accrued bonus	175,000	—
Gain on sale of property	—	(12,210,000)
NOL carryforwards	5,548,000	5,598,000
Valuation allowance	(5,887,000)	(5,789,000)
Net deferred tax liability	$ (338,000)	$ (12,362,000)

For year ended June 30, 2007, we have a current income tax expense of $11.4 million (split $10 million for federal income taxes and $1.4 million for state income taxes due) and a deferred tax benefit of approximately $12 million, primarily as a result of the Delhi Farmout in which we received approximately $50 million of pre-tax proceeds. In determining the $11.5 million of current tax expense, we used $39,700 of pre-merger Reality NOL's.

We have established a full valuation allowance against our net deferred tax assets totaling $5.89 million for fiscal year ended 2007, and we will continue to take a full valuation allowance until an appropriate level of profitability is attained. Of t his amount, $5.31 million of deferred tax assets are permanently impaired absent a change in Internal Revenue Code Section 382 legal limitations imposed on the Reality NOL's we inherited in the merger. If not used, our unimpaired tax assets will expire between 2010 and 2023.

On June 12, 2006, we consummated the Delhi Farmout as a completed sale for tax purposes. The completed sale designation was important to our ability to consummate IRC Section 1031 like kind exchanges, thus potentially deferring federal income tax liability by rolling the basis of the our Delhi property into similar like kind properties we might have purchased within the short timeframes allowed under current tax law. Of the $50 million of proceeds we received from Denbury Resources for our Delhi Farmout, we plac ed $35 million in a qualified intermediary ("QI") account for possible Internal Revenue Code 1031 "like-kind exchanges" (which was available to us at any time) and placed the remaining $15 million in an unrestricted account which triggered immediate taxable "boot" on the $15 million portion we received. As of June 30, 2006, we had approximately $34.7 million of cash held in the QI account, providing us the opportunity to defer the recognition of taxable gain on up to $35 million we received from the Delhi Farmout in the event that like-kind property was purchased within 180 days from the date of the outgoing property sale (being December 9, 2006) for assets identified within 45 days of such sale. As of June 30, 2006, we had utilized $420,000 from the QI account to acquire like-kind property (partially offset by approximately $82,000 of interest income earned on the QI account). As of June 30, 2007, only an additional $159,000 of additional replacement property has been acquired. As such, the remaining deferred gain became a taxable gain in fiscal year end June 30, 2007 by means of an installment sale.

The following is a reconciliation of the Company's expected income tax expense (benefit) based on statutory rates to the actual expense (benefit):

	Year ended 2007	Year ended 2006
Income taxes (benefit) at U.S. statutory rate	$ (857,000)	$ 14,247,000
State taxes net of federal benefit	(89,000)	1,376,000
Non-deductible interest expense and deferred compensation	283,000	456,000
Deferred tax asset valuation allowance adjustment	151,000	(1,160,000)
IRC section 199 deduction	(155,000)	(74,000)
Other	28,000	163,000
Total	$ (639,000)	$ 15,008,000

The U. S. statutory rate is 35%. The state of Louisiana tax rate, net of federal tax benefit is 3.4%. The blended tax rate is 38.4%

The deferred tax asset valuation allowance adjustment is due to an increase in deferred tax assets from the prior year.

13. Operating Leases

We have a commitment under an operating lease agreement for office space for our corporate headquarters. Total rent expense for the years ended June 30, 2007 and 2006 was approximately $81,000 and $43,000, respectively. At June 30, 2007, future minimum rental payments due under this operating lease are as follows:

Year ending June 30:		
2008	$	115,074
2009		138,089
2010		138,089
2011		138,089
2012		157,268
Thereafter		649,295
Total	$	1,335,904

14. Commodity Contracts

In compliance with the loan agreement we entered into with Prospect Energy in February 2005, we executed three commodity contracts for approximately 50% of the production volumes that our outside petroleum engineers estimated for our proved developed producing reserves on a rolling two year basis. Although we paid off the Prospect loan in May 2006, performance under these contracts remained effective through fiscal 2006 and 2007, as described below.

The first commodity contract, with Plains Marketing L.P., covered the sale of 70 barrels of crude oil per day for a 12 month period from March 2005 through February 2006. The fixed sale price was based upon the NYMEX WTI (West Texas Intermediate) crude oil price and monthly settlements, wherein Plains Marketing delivered a fixed price of $48.35 per barrel to us before adjustment for the basis differential between the NYMEX price and the contract price. This contract was extended for the months of March 2006 through May 2006 at a fixed price of $52.55 per barrel of oil for 70 barrels of oil per day, extended for the three months of June 2006 through August 2006 at a fixed price of $63.45 per barrel of oil for 90 barrels of oil per day, and extended for the six months of September 2006 through February 2007 at a fixed price of $69.30 per barrel of oil for 90 barrels of oil per day.

The second commodity contract was between us and Wells Fargo Bank, N.A. We purchased a series of price floors, set at a NYMEX WTI price of $38.00 per barrel of crude oil, based upon the arithmetic average of the daily settlement price for the first nearby month of NYMEX WTI futures, for 2,000 barrels of crude oil per month for March 2006 through February 2007. The cost of the hedge was $3.00 per barrel of oil.

Our third commodity contract was with Texla Energy Management, Inc., whereby we sold 100 MMBTU per day at a fixed price of $6.21 per MMBTU over a fifteen month period beginning March 1, 2005, and ending May 31, 2006.The fixed price was before deduction of a $0.0854 per MMBTU fixed gathering charge by Gulf South, the owner of the natural gas pipeline into which we deliver our natural gas from the Delhi Field. This fixed price included the basis differential from NYMEX to our sales point on the Gulf South pipeline.

Since March 1, 2007, all of our oil production has been sold to Plains Marketing L.P. under a normal (thirty day “evergreen”) sales contract.

15. Earnings (loss) per Share

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

	Year ended	
	June 30, 2007	June 30, 2006 (as restated)
Numerator:		
Net income (loss) applicable to common stockholders	$ (1,810,211)	$ 25,698,366
Plus income impact of assumed conversions:		
Preferred Stock dividends	N/A	N/A
Interest on convertible subordinated notes	N/A	N/A
Net income (loss) applicable to common stockholders plus assumed conversions	$ (1,810,211)	$ 25,698,366
Denominator:	26,706,713	25,031,125
Affect of potentially dilutive common shares:		
Warrants	N/A	176,072
Employee and director stock options	N/A	348,795
Convertible preferred stock	N/A	N/A
Convertible subordinated notes	N/A	N/A
Redeemable preferred stock	N/A	N/A
Denominator for dilutive earnings per share - weighted average shares outstanding and assumed conversions	26,706,713	25,555,992
Earnings (loss) per common share:		
Basic	$ (0.07)	$ 1.03
Diluted	$ (0.07)	$ 1.01

16. Major Customers

All of our crude oil is currently sold to Plains Marketing L.P. (Plains) and committed through the life of our fixed price crude oil sales contracts, which expired with February 2007 sales. Effective March 2007, the oil sales contract is a normal ("evergreen") sales contract with Plains.

All of our natural gas production was sold to Texla Energy Management. However, since the closing of the Delhi Farmout in June 2006, we had no natural gas production to sell.

17. 401(k) 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. Our matching contribution to the plan was approximately $36,000 for the fiscal year ended June 30, 2007.

18. Subsequent Events

On August 3, 2007, we were advised of an oil spill in the Tullos Field near one of our leases. At the request of field agents of the Louisiana Department of Environmental Quality and the EPA, we agreed to commence a clean up operation that was completed by the end of August 2007. A detailed analysis of the oil in the spill compared to our produced oil was conducted by an EPA approved laboratory. We believe that the various independent analyses show, supported by the formal findings of the laboratory, that the oil in the spill did not originate from our operations. We also believe that most of the estimated $600,000 of costs incurred in the cleanup, before adjustment following audit and negotiation of the billings, will be covered by insurance or reimbursement from the relevant government oil spill funds, but we can give no assurance that such reimbursement will occur. All clean up costs, net of any reimbursements, will be expensed as incurred.

In August 2007, the board of directors approved a resolution to issue a total of 125,000 shares of common stock options to three new employees as part of their total compensation for employment. The options are excisable at the closing price of the common stock on the date of issuance and vests in equal amounts quarterly over four years and subject to other standard terms and conditions as provided by the Company.

In September 2007, the board of directors approved a resolution to issue a total of 1,010,000 shares of common stock options to existing employees as part of their long term incentive compensation. The options are excisable at the closing price of the common stock on the date of issuance and vests in equal amounts quarterly over four years and subject to other standard terms and conditions as provided by the Company.

Report of Independent Registered Public Accounting Firm

The 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, 2007 and 2006 and the related consolidated statements of operations, stockholders' equity, and cash flows for the years ended June 30, 2007 and 2006. 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. The Company has determined that it is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. 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 and subsidiaries as of June 30, 2007 and 2006, and the consolidated results of their operations and their cash flows for each of the years then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 3 to the financial statements, the Company has restated the accompanying financial statements to correct an error in the tax provision.

As discussed in Note 7 to the consolidated financial statements, the Company adopted Statement of Accounting Standards No. 123 (revised 2004), "Share-Based Payment," during the year ended June 30, 2007.

HEIN & ASSOCIATES LLP

Houston, Texas
September 25, 2007

ITEM 8. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

ITEM 8A. CONTROLS AND PROCEDURES.

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. As required by SEC Rule 13a-15(b), we carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report.

Based on the foregoing, our Chief Executive Officer and Chief Financial Officer concluded that, as of the end of the period covered by this report, our disclosure controls and procedures were effective in ensuring that the information required to be disclosed in reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC rules and forms and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

There was no change in our internal control over financial reporting during our last fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 8B. OTHER INFORMATION.

None.

PART III

ITEM 9. DIRECTORS, EXECUTIVE OFFICERS, PROMOTERS AND CONTROL PERSONS AND CORPORATE GOVERNANCE COMPLIANCE WITH SECTION 16(A) OF THE EXCHANGE ACT.

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 2007 fiscal year.

ITEM 10. 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 2007 fiscal year.

ITEM 11. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDERS 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 2007 fiscal year.

ITEM 12. 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 2007 fiscal year.

ITEM 13. EXHIBITS.

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)
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)
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)
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)

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)
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)
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)

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 2007 fiscal year.

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
Chief Executive Officer
(Principal Executive Officer)

By: */s/ STERLING H. MCDONALD*
Sterling H. McDonald
Vice President and Chief Financial Officer
(Principal Financial and
Accounting Officer)

Date: September 28, 2007

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 28, 2007	*/s/ E. J. DIPAOLO* *E. J. DiPaolo*	*Director*
September 28, 2007	*/s/ GENE STOEVER* *Gene Stoever*	*Director*
September 28, 2007	*/s/ WILLIAM DOZIER* *William Dozier*	*Director*
September 28, 2007	*/s/ LAIRD Q. CAGAN* *Laird Q. Cagan*	*Chairman of the Board*
September 28, 2007	*/s/ ROBERT S. HERLIN* *Robert S. Herlin*	*Director*

EXHIBIT 21.1

Subsidiaries of Evolution Petroleum Corporation

Subsidiary	State of Incorporation organization	Name under which entity does business
Natural Gas Systems, Inc.	Delaware	Natural Gas Systems
NGS Sub Corp.	Delaware	Natural Gas Systems
ARKLA Petroleum, LLC	Louisiana	Arkla Petroleum LLC
Four Star Development Corporation	Louisiana	Natural Gas Systems Four Star Development Corporation and Natural Gas Systems
NGS Technologies, Inc	Delaware	NGS Technologies, Inc.
Evolution Operating Co., Inc.	Texas	Evolution Operating Co., Inc.

Exhibit 23.1

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 25, 2007, relating to the financial statements of Evolution Petroleum Corporation and subsidiaries appearing in the Form 10-KSB for the period ended June 30, 2007.

/s/ Hein & Associates LLP
Hein & Associates LLP

Houston, Texas
September 25, 2007

500 Dallas, Suite 2900
Houston, Texas 77002
Phone: 713-850-9814
Fax: 713-850-0725
www.heincpa.com

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

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, 2007” in the relevant pages of the 10-KSB of Evolution Petroleum Corporation for the fiscal year ended June 30, 2007.

W.D. Von Gonten & Co. has no interests in Evolution Petroleum Corporation or in any affiliated companies or subsidiaries and is not to receive 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,

W.D. VON GONTEN & CO.

/s/ William D. Von Gonten, Jr.

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

September 25, 2007

Exhibit 31.1

CERTIFICATION 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

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

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

2. Based on my knowledge, this annual 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 small business issuer as of, and for, the periods presented in this report;

4. The small business issuer’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)) for the small business issuer 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 small business issuer, 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) Evaluated the effectiveness of the small business issuer’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

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

5. The small business issuer’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the small business issuer’s auditors and the audit committee of the small business issuer’s Board of Directors:

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 small business issuer’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 small business issuer’s internal control over financial reporting.

Date: *September 28, 2007*

/s/ *ROBERT S. HERLIN*
Robert S. Herlin
Chief Executive Officer

Exhibit 31.2

CERTIFICATION 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

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

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

2. Based on my knowledge, this annual 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 small business issuer as of, and for, the periods presented in this report;

4. The small business issuer’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)) for the small business issuer 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 small business issuer, 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) Evaluated the effectiveness of the small business issuer’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

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

5. The small business issuer’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the small business issuer’s auditors and the audit committee of the small business issuer’s Board of Directors:

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 small business issuer’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 small business issuer’s internal control over financial reporting.

Date: September 28, 2007

/s/ STERLING H. MCDONALD
Sterling H. McDonald
Chief Financial Officer

Exhibit 32.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
(18 U.S.C. 1350)

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-KSB for the year ended June 30, 2007 (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 28th day of September, 2007.

/s/ ROBERT S. HERLIN
Robert S. Herlin
Chief Executive Officer

Exhibit 32.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
(18 U.S.C. 1350)

The undersigned, Sterling H. McDonald, 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-KSB for the year ended June 30, 2007 (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 28th day of September, 2007.

/s/ STERLING H. McDONALD
Sterling H. McDonald
Chief Financial Officer