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

Form 10-KSB

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

For The Fiscal Year Ended June 30, 2006

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

For the transition period _________ to _________

Commission File Number: 0-27862

EVOLUTION PETROLUEM CORPORATION
(Exact name of registrant as specified in charter)

Nevada	41-1781991
(State of incorporation)	(I.R.S. employer identification number)

820 Gessner, Suite 1340, Houston, Texas 77024
(Address of principal executive offices and zip code)

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

Securities registered pursuant to Section 12(b) of the Exchange Act:
Common Stock, $.001 Par Value
(Title of class and shares outstanding)

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

None.

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

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

Issuer's revenues for its most recent fiscal year: $2,861,414

As of September 1, 2006, the aggregate market value of common stock held by non-affiliates of the registrant was approximately $37 million, assuming solely for purposes of this calculation that all directors and executive officers of the registrant and all stockholders beneficially owning more than 10% of the registrant's common stock are "affiliates." This determination of affiliate status is not necessarily a conclusive determination for other purposes.

The number of shares of common stock outstanding on September 1, 2006 was 26,651,997 shares.

DOCUMENTS INCORPORATED BY REFERENCE into Part III hereof Portions of the Proxy Statement to be filed with the Commission in connection with the Company's 2006 Annual Meeting.

Transitional Small Business Format (Check One): Yes |_| No |X|

EVOLUTION PETROLEUM
CORPORATION AND SUBSIDIARIES

2006 ANNUAL REPORT ON 10-KSB

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PART III

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.

"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 (BTU's).

"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.

"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" or "PV-10." 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 of ten percent and assuming continuation of existing economic conditions. PV-10 means a present value, discounted at 10% per annum.

"productive well." A well that is producing oil or gas or that is capable of production.

"royalty" or "royalty interest." The mineral owner's share of oil or gas production (typically 1/8, 1/6 or 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 same 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., and, unless the context indicates otherwise, also includes our wholly-owned subsidiaries. "Old NGS" refers to Natural Gas Systems, Inc., a private Delaware corporation formed in 2003.

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).

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 820 Gessner, Suite 1340, Houston, Texas 77024, 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.

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. 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:

- Enhanced oil recovery (EOR) projects in mature oil reservoirs;
- Redevelopment of mature oil and gas fields using modern and/or proprietary technology; and
- Development of low permeability resource plays using modern stimulation and completion technologies, including horizontal drilling.

Our strategy is designed to generate scalable development opportunities at relatively shallow 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 ~7.4%.

In June 2006, we conveyed a farmout to Denbury Resources 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% 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").

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

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.

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.

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 also 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 crude oil production to Plains Marketing LP, a crude oil purchaser, at competitive field prices. A portion of our crude oil production is 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.

We have sold all of our natural gas liquids 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.

There is only one natural gas pipeline sales point readily available to our gas treating facility serving our Delhi natural gas production, which reduces our leverage in negotiating a more favorable transportation charge and sales price. The current natural gas sales line is also a delivery line to customers, downstream of the pipeline's processing and treating facilities, thus making the pipeline very sensitive to the quality of natural gas sold into our point of interconnection.

Since March 2005, we have sold all of our natural gas 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 has been sold under commodity contracts, as discussed in the section below. The remaining natural gas volumes are 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 is 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, are deducted from the natural gas sales receipts before calculation and distribution of royalties. Title to the natural gas passes to the purchaser at the metered interconnection to the transportation pipeline, where the Index price is 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, two of these contracts continue to extend through February 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.

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 (Please see Item 3. Legal Proceedings). We cannot predict what subsequent legislation or regulations may be enacted or what effect it will have on our operations or business.

RISK FACTORS

Risks related to the Company

FORWARD LOOKING RESULTS WILL CHANGE

Due to the 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 to fund and operate. The Delhi Farmout will result in the immediate reduction in net production and net revenues accruing to us from Delhi, until such time, if at all, as the EOR project is completed and brought online. Without further acquisitions of new properties, or production increases at our Tullos Field Area, our production and revenues from oil and gas production will decline in the foreseeable future, as compared to our fiscal 2006 results. Nevertheless, we believe that the $50 million pre-tax cash payment we received from the Delhi Farmout, the interest income earned on these proceeds and the oil production from our Tullos Field Area operations will provide sufficient liquid resources to fund our operations and capital program for the foreseeable future.

THE TYPES OF RESOURCES WE FOCUS ON HAVE CERTAIN 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 ~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 mange 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 farmout transaction with Denbury, we have incurred significant losses since the inception of our oil and gas operations. 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 propriety 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 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 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 credit facility, we entered into three commodity contracts. Although we terminated our credit facility in May 2006, two of these contracts extend through February 2007. After June 2006, these arrangements apply to virtually all of our crude oil production and provide price protection against declines in crude oil prices. Our 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, our 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.

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, for capital raising, sourcing and evaluating and closing deals, and oversight of development and operations.

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 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.

We hope to experience rapid growth through acquisitions and development activity. Any future 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 prospects;
- 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 99% of our reserves at July 1, 2006 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. 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 twelve months prior to June 30, 2006, our stock price as traded on the OTC Bulletin Board ranged from $1.00 to $3.70. The variance in our stock price makes it extremely difficult to forecast with any certainty the stock price at which an investor may be able to buy or sell shares of our common stock. The market price for our common stock could be subject to wide fluctuations as a result of factors that are out of our control, such as:

- actual or anticipated variations in our results of operations;
- naked short selling of our common stock and stock price manipulation;

- changes or fluctuations in the commodity prices of crude oil and natural gas;

- general conditions and trends in the crude oil and natural gas industry; and

- general economic, political and market conditions.

OUR EXECUTIVE OFFICERS, DIRECTORS AND AFFILIATES MAY BE ABLE TO CONTROL THE ELECTION OF OUR DIRECTORS AND ALL OTHER MATTERS SUBMITTED TO OUR STOCKHOLDERS FOR APPROVAL.

Our executive officers and directors, in the aggregate, beneficially own approximately 36% of our outstanding common stock. Further, 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 (including shares issuable upon the exercise of warrants), or approximately 29% of our outstanding common stock. Mr. Eric McAfee, a Managing Director of CMCP, currently owns or controls, directly or indirectly, approximately 5.9 million shares (including shares issuable upon the exercise of warrants), or approximately 22% of our outstanding common stock, but is neither an officer nor a member of our board of directors. Collectively, these two managing directors of CMCP currently own or control, directly or indirectly, approximately 13.6 million shares (including shares issuable upon the exercise of warrants), or approximately 50% of our outstanding common stock. As a result, these holders, if they were to act together, could exercise 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 twelve months prior to June 30, 2006, the actual trading volume in our common stock ranged from a low of no shares of common stock traded to a high of over 356,000 shares of common stock traded, with only 75 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, no non-company paid analysts cover our company. The lack of published reports by independent securities analysts could limit the interest in our common stock and negatively affect our stock price. We do not have any control over the research and reports these analysts publish or whether they will be published at all. If any analyst who does cover us downgrades our stock, our stock price 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.

Delhi Field

The Delhi Holt Bryant Unit in the Delhi Field, currently our most strategic asset, is in the early stages of being redeveloped through an enhanced oil recovery (EOR) project utilizing CO_2 technology. 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 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 Resources 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"), 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 successful CO2 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 CO2 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 Resources, Inc. (NYSE: DNR). 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.

- DNR committed to install a CO2-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.

- DNR, the dominant CO2-EOR operator on the Gulf Coast, currently operates several CO2-EOR projects, and owns naturally occurring CO2 reserves we believe to be sufficient to meet the needs of 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).

- Our 25% back-in working interest in the CO2-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 CO2 and demonstration of production response.

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. In addition we acquired 15 crude oil wells that 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 generally 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 the first well has been approved by state agencies for use and we believe that the balance of the seven conversions will be completed in calendar year 2006.

For the month of June 2006, we produced approximately 118 BOPD from our Tullos Field Area. As only one service rig is available, its use in converting wells to water disposal utility creates a growing backlog of producing wells being shut in for repairs and maintenance.

We are reviewing the results of our development program and the ongoing high level of required maintenance and repairs to determine other options to produce the substantial remaining oil potential while reducing operating costs.

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.

We occupy 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 2004, we extended our lease for three years, and the right to use furniture and fixtures without cost.

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 and Tullos Field Area as of July 1, 2006. Von Gonten also previously prepared an independent report of our proved reserves at 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, 2006, natural gas represented 1% and crude oil represented 99% of total proved reserves, denominated in equivalent barrels using a six MCF of gas to one barrel of oil conversion ratio, as compared to 14% and 86%, respectively, at July 1, 2005. The reduction in proved reserves was due to the Delhi Farmout.

The following table sets forth, as of July 1, 2006 and July 1, 2005, 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 $73.93 and $56.50 per barrel of oil and $6.10 and $6.98 per MMBTU of gas as of June 30, 2006 and June 30, 2005, 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%
Jul 1, 2006	460,525	25,800	$14,141,560	$ 8,038,791
Jul 1, 2005	771,817	732,300*	$24,892,850	$17,479,486

* NGL reserves of 7,300 as of July 1, 2005 are included in the above gas volumes, at a 6:1 ratio.

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

At July 1, 2005, Proved Developed reserves (including Proved Behind Pipe) totaled 68% 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:

	12 months ended June 30, 2006		12 months ended June 30, 2005	
Product	Volume	Price	Volume	Price
Gas (mcf)	45,368	$ 9.35	54,137	$ 6.62
Oil (bbls)	45,091	$54.05	27,230	$46.89

Average production costs, including production taxes, per unit of production (using a six to one conversion ratio of mcf's to barrels) were $34.49 and $26.02 per barrel of oil equivalent for the twelve months ended June 30, 2006 and 2005, respectively.

Productive Wells and Developed Acreage

Developed acreage at June 30, 2006 totaled 519 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 last year by 13,636 acres, due to the Delhi Farmout, which became effective as of June 1, 2006.

At June 30, 2006, we owned working interests in 262 net and gross wells consisting of 165 crude oil wells, 22 salt water disposal wells and 75 shut-in wells with uncertain future utility located in the Tullos Field Area. Approximately 65 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. The number of wells has declined by 44 wells from June 30, 2005 due to the farm-out of our Delhi Holt Bryant Unit effective June 1, 2006.

Undeveloped Acreage

As of June 30, 2006, all of our working interest acreage is held by production through a unitization agreement or lease agreements on developed properties.

Drilling

During the twelve months ended June 30, 2006, we drilled and completed 5 new wells in the Delhi Field. For the twelve months ended June 30, 2005, no new wells were drilled.

Subsequent Events

Natural Gas Systems, Inc changed its name to "Evolution Petroleum Corporation" effective July 11, 2006, to avoid confusion with similar names on the AMEX and to better reflect our business model. The name change was effectuated without shareholder approval pursuant to a statutory short-form merger with a wholly owned subsidiary, followed by the name change, in accordance with the provisions of Nevada law.

On July 17, 2006, Evolution Petroleum Corporation started trading its common stock on the American Stock Exchange ("AMEX") under the EPM ticker symbol.

On July 21, 2006, we funded and closed the acquisition of royalty and overriding royalty interests aggregating 0.39% in the Delhi Holt Bryant Unit from an unrelated third party owner.

Item 3. Legal Proceedings.

On November 17, 2005, a multi-plaintiff lawsuit was filed in the Fifth Judicial District Court, Richland Parish, Louisiana, against 26 defendants, including two of our subsidiaries, Arkla Petroleum L.L.C. ("Arkla") and NGS Sub Corp (together with Arkla, the "Subsidiaries"). We were not served with, notified or aware of, the lawsuit until February 2006.

The plaintiffs claim to be landowners whose property (including the soil, surface water, and groundwater) has been contaminated by oil and gas exploration, production and development activities conducted by the defendants on the plaintiffs' property and adjoining land since the 1930's (including activities by Arkla as operator of the Delhi Field subsequent to Arkla's formation in 2002 and our acquisition of Arkla in 2003, and activities since NGS Sub Corp's acquisition of a 100% working interest in the Delhi Field in 2003). The plaintiffs claim that the defendants knew of the alleged dangerous nature of the contamination and actively concealed it rather than remedy the problem.

The plaintiffs are seeking unspecified compensatory damages and punitive damages, as well as an order that the defendants restore the property and prevent further contamination. Our ultimate exposure related to this lawsuit is not currently determinable, but could, if adversely determined, have a material adverse effect on our financial condition. Our costs to defend this action, which we currently believe is not covered by our insurance policies, could also have a material adverse effect on our financial condition.

During the quarter ended March 2006, we filed our response and Motion to Stay Proceedings and Dilatory and Declinatory Exceptions with respect to this proceeding.

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.

Our common stock trades on the American Stock Exchange ("AMEX") under the ticker symbol EPM, effective July 17, 2006. Prior to this time, our stock traded on the OTC Bulletin Board National Association of Securities Dealers Automated Quotation System under the symbol "NGSY" and its predecessor symbol "RLYI". The following table sets forth the high and low bid prices per share of our Common Stock for each of the calendar quarters identified below as reported by the OTC Bulletin Board. These quotations represent inter-dealer prices, without retail mark-up, markdown or commission, and may not represent actual transactions. Furthermore, the prices have been adjusted for a 40:1 stock split that occurred on February 5, 2004.

2006:	High	Low
Quarter ended June 30, 2006	$3.70	$2.01
Quarter ended March 31, 2006	$2.65	$1.31

2005:	High	Low
Quarter ended December 31, 2005	$2.05	$1.15
Quarter ended September 30, 2005	$2.05	$1.00
Quarter ended June 30, 2005	$3.47	$1.32
Quarter ended March 31, 2005	$2.30	$1.55

2004:	High	Low
Quarter ended December 31, 2004	$2.30	$1.45
Quarter ended September 30, 2004	$3.75	$2.05

At September 22, 2006, we had 1,782 shareholders of record.

We have never paid a cash dividend and we do not expect to pay any cash dividends in the foreseeable future. Earnings, if any, are expected to be reinvested in business activities. No stock has been repurchased by us since the merger of Old NGS into us in May, 2004.

Securities authorized for issuance under equity compensation plans

As of June 30, 2006, options to purchase 2,361,000 shares had been granted under the 2004 Stock Plan and 145,000 shares were issued directly under the same plan. The purpose of the 2004 Stock Plan is to grant equity compensation in the form of stock grants, options or warrants to purchase our common stock to our employees and key consultants.

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	3,016,000(1)	$1.42	1,494,000
Equity compensation plans not approved by security holders	1,478,021(2)	$1.50	--
Total	4,494,021	$1.44	1,494,000

(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, 2006, 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, 2006, there were 2,361,000 shares of common stock issued or issuable upon exercise of outstanding options and 145,000 shares issued directly under the 2004 Stock Plan leaving 1,494,000 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 312,931 shares of common stock at an exercise price of $1.00, with a seven year term (warrants). We issued 240,000 of these warrants to CMCP and their assigns in connection with arranging the merger and 72,931 were issued to Laird Q. Cagan, Chadbourn Securities and their assigns in connection with capital raising services. Subsequently, we issued a warrant 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 5,000 shares for capital raising services in connection with the loan agreement with Prospect Energy Corporation, 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 incentive 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

This information was previously reported on our 10-QSB and Current Form 8-K filed during the fiscal year ended June 30, 2006.

Item 6. Management's Discussion and Analysis or Plan of Operation.

Liquidity and Capital Resources

As of June 30, 2006, we had approximately $9.9 million of unrestricted cash and $34.7 million of cash held in a qualified intermediary ("QI") account for possible Internal Revenue Code 1031 "like-kind exchanges", all of which is available to us at any time. 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 (being December 9, 2006) for assets identified within 45 days of such sale. Concurrent with the closing of the Delhi Farmout, we established the QI account with $35 million of the $50 million of proceeds we received from Denbury at closing, $420,000 of which has been used to acquire like-kind property on or prior to June 30, 2006 (partially offset by approximately $82,000 of interest income earned on the QI account). In the event that we choose to withdraw any funds from the qualified intermediary account to fund non like-kind exchanges, or fail to use all of the funds prior to December 9, 2006, all of the funds remaining or disbursed from the QI account will become subject to immediate taxable gain on the sale of the Delhi property.

At June 30, 2006 we had $6.5 million of positive working capital, as compared to $2.6 million of positive working capital at June 30, 2005. Our working capital at June 30, 2006 does not include the $34.7 million of cash deposited in the QI account for possible like-kind exchanges, or the $13.1 million of deferred tax liability associated with such cash receipt deferral, as they are recorded as non-current assets and liabilities, respectively.

Cash flow used by our operating activities was $0.7 million for the twelve months ended June 30, 2006, as compared to $1 million used during the fiscal year ended June 30, 2005.

Cash flow provided by investing activities was approximately $11.8 million for the twelve months ended June 30, 2006. Approximately $50 million of cash was provided by the Delhi Farmout. Of the major investing activities, approximately $34.7 million was invested in the QI account for possible 1031 "like-kind" exchanges, approximately $1.4 million was used to acquire additional royalty and overriding royalty interests in the Delhi Holt Bryant Unit, $2.6 million was used to develop our oil and gas properties (primarily in the Delhi Field prior to our divestiture). In the prior fiscal year, we used $1.6 million to acquire working interests in our Tullos Field Area, approximately $0.5 million was used in developing our properties, and $0.6 million was used to fund the Prospect Debt Service Reserve account.

During the twelve months ended June 30, 2006, we borrowed $1.04million and received $1.0 million in proceeds (net of transaction costs) from the sale of 351,553 shares of common stock and the issuance of warrants to Prospect with respect their additional loan, prior to the repayment of all of our debt in the amount of $5.6 million.

These transactions, especially the Delhi Farmout, have allowed us to:

- Further strengthen our balance sheet to fund new development projects in accordance with our business plan to exploit known petroleum resources.;

- Participate in a major enhanced oil recovery project without our incurring further capital expenditures or scaled up operations; and

- Repay all of our debt.

Although our future development initiatives in the Delhi Field are expected to be replaced with a CO2-EOR project offering much greater potential, the Delhi Farmout will result in the immediate reduction in 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, or production increases at our Tullos Field Area, our production and revenues from oil and gas production will decline in the foreseeable future, as compared to our fiscal 2006 results. Nevertheless, we believe that the $50MM of pre-tax proceeds that we received from the Delhi Farmout, the interest income earned on these proceeds and the oil production from our Tullos Field Area operations will provide sufficient liquid resources to fund our operations and capital program for the foreseeable future.

Product Prices and Production

Refer to Item 1, "Markets and Customers", for discussion of oil and gas prices and marketing.

Although product prices are key factors in our ability to operate profitably and to budget capital expenditures, they are beyond our control and are difficult to predict.

Refer to Item 2, "Properties", for disclosures regarding reserve values and for a summary on production, average sales prices and average production costs.

Oil and Gas Activities

General

Our oil and gas activities for the fiscal year 2006 included ongoing development of our fields in Louisiana, completion of our development drilling program in the Delhi Field, purchase of additional royalty and overriding royalty interests in the Delhi Holt Bryant Unit, and, most importantly, completion of the Delhi Farmout. Important aspects of the Delhi Farmout include:

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

- DNR committed to install a CO2-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.

- DNR, the dominant CO2-EOR operator on the Gulf Coast, currently operates several CO2-EOR projects, and owns naturally occurring CO2 reserves we believe to be sufficient to meet the needs of 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).

- Our 25% back-in working interest in the CO2-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 CO2 and demonstration of production response.

Reserves

Refer to Item 2, "Properties, General, Estimated Proved Oil and Gas Reserves and Future Net Reserves", for information regarding oil and gas reserves.

Results of Operations

Fiscal year ended June 30, 2006 compared to fiscal year ended June 30, 2005

Revenues. Our revenues were $2.9 million in fiscal year 2006, compared to revenue of $1.6 million in fiscal year 2005. This 75% increase in revenues was primarily due to increased oil sales of approximately 65%, offset by a 16% decrease in gas sales. In addition, overall commodity prices were higher by 11% and 41%, respectively, for oil and gas. Increased oil sales were due to development activity at our Delhi Field, a full year of production from our Tullos Field Area and improved commodity prices. Gas sales decreased due to depletion of gas reservoirs.

Lease Operating Expenses. The 97% increase in our lease operating expenses is primarily due to an increase in the number of wells operated in 2006 versus 2005 and well work-over costs. Fiscal 2006 includes a full year of operating expenses for the Tullos Field Area, which assets were purchased during early and mid fiscal year 2005. In addition, lease operating expenses increased due to substantial overall industry cost increases and due to an increase in drilling and production activity.

Production taxes. The 27% increase in production (severance) taxes is directly related to the increase in net production and sales.

General and Administrative expenses (G&A). Our G&A expenses increased 27% in fiscal 2006 as compared to fiscal 2005, primarily due to the addition of two full time employees in late fiscal 2005 and accrual of cash bonuses for fiscal year 2006, offset slightly by reduced non-cash stock compensation expense of $546,567 during fiscal 2006, as compared to $707,117 during fiscal 2005. Our G&A expenses continue to be high 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 market for skilled energy staff.

Depletion, Depreciation and Amortization (DD&A). DD&A expenses are recorded on the full cost method of accounting. Depletion and depreciation of oil and gas properties is on a unit of production basis. In the fiscal year ended 2006, the average DDA rate per BOE was up 13% percent to $7.48 per barrel of oil equivalent, compared to prior year of $6.63 per barrel of oil equivalent. This increase is attributable to higher capital spending than estimated for the Delhi Development drilling program. Depreciation of office equipment and computer equipment is computed on a straight line basis.

Interest Income. Our interest income increased significantly, from $11,709 to $165,313 due to higher cash balances and higher interest rates.

Interest Expense. Interest expense increased significantly from $387,301 to $2,600,180 primarily due to the Prospect note payable. Specifically, cash interest paid was approximately $600,000, imputed interest expense was approximately $1,302,000 and amortization of deferred financing fees and other loan costs was approximately $698,000 were all related to the Prospect note and the early pre-payment of such note during fiscal year 2006.

Gain on sale of asset. As the result of the approximately $50 million in pre-tax cash proceeds we received from the Delhi Farmout, we recorded a pre-tax gain on the sale of assets for approximately $45 million after adjustments for customary closing costs and buyer and seller credits.

Net income. We reported a net income of $24.6 million for the fiscal year 2006, compared to a net loss of $2.2 million for the previous year. The primarily reason for the net income in current the year is the $45 million pre-tax gain we recorded from the Delhi Farmout.

Earnings / (loss) per share (EPS). For fiscal year 2006, basic and diluted EPS was $0.98 and $0.96, respectively. For prior fiscal year, basic and diluted EPS was $(0.09).

Our results of operations were positively impacted by the following events during the fiscal year 2006:

- Receipt of approximately $50 million (pre-tax) for our Delhi Farmout;

- Completion of our first full year of operations in the Tullos Field Area;

- Successful drilling and completion of our Delhi Ut. #92-2 and Delhi Ut. #70-4; and

- High crude oil and natural gas prices.

Our operating results for the year ended June 30, 2006 were adversely impacted by the following events:

- With respect to our Delhi Development Drilling Program:

  The Delhi Ut. 92-2 depleted far more rapidly than projected.

  Drilling results in the Delhi Ut. 87-3, 139-2 and 225-2 yielded reservoirs that require additional stimulation to reach the expected production rates, and required substantial completion activities in excess of budgeted expenditures.

  The program was substantially delayed due to unavailability of a drilling rig, and the poor quality of the drilling rig and operating crew received contributed to results less than projected and far higher costs than budgeted.

- With respect to our Tullos Field Area:

  The high industry demand for workover service rigs hampered our ability to carry out our maintenance, repair and development programs in a timely manner.

Delays in permit approvals necessary to convert wells to water disposal utility substantially delayed our development program at Tullos.

The following remedial actions have been or are planned to be taken:

- We have replaced our Delhi Development Drilling Program with a much larger CO_2-EOR project.
- We have begun a search for a General Manager for Tight Gas Development and Drilling;
- We are focusing our new development projects in areas with greater access to field services; and
- With respect to our Tullos Field Area, we:

  Received the seven water disposal well permits we requested. Conversion operations, to be followed by final regulatory approvals, are in process.

  Contracted to purchase a field yard in the Tullos Field Area in order to consolidate operations and inventory.

  Are considering alternative options to recover oil in the Tullos Field Area and reduce operating expenses.

  Plan on replacing certain high maintenance beam pumps with submersible pumps, potentially reducing maintenance expense and production downtime.

Following is a summary of the progress we have made in both sales volumes and revenues, net to our interest:

Net to EPM for the quarters ended:	Units	9/30/2004	12/31/2004	3/31/2005	6/30/2005	9/30/2005	12/31/2005	3/31/2006	6/30/2006*
Oil & Gas Revenue	$	$231,167	$365,768	$402,305	$635,948	$542,884	$830,936	$878,602	$608,993
Oil volumes sold	BO	3,955	5,234	6,545	12,644	10,639	11,860	13,890	10,553
Gas volumes sold	MCF	11,252	15,679	16,378	10,828	9,811	24,110	10,147	1,300
Barrels of oil equivalent sold	BOE	5,830	7,847	9,275	14,449	12,274	15,878	15,581	10,770
Oil price (incl hedging gain or losses)	$BBL	$ 42.66	$ 47.94	$ 47.61	$ 50.78	$ 45.72	$ 47.00	$ 57.67	$ 57.41
Gas price (incl hedging gain or losses)	$/MCF	$ 5.55	$ 7.32	$ 6.71	$ 6.35	$ 5.90	$ 11.57	$ 8.25	$ 2.75

* only two months of Delhi field results are included as a result of the Delhi Farmout becoming effective as of June 1, 2006.

Highlights of our performance from July 1, 2004 to June 30, 2006:

- We have generally increased revenues for each quarter, primarily due to both production and commodity price increases; and
- We have generally increased sales volumes for each quarter due to increases in production for both fields.

Critical Accounting Policies and Estimates

Accounting for Oil and Gas Property Costs. As more fully discussed in Note 3 to the consolidated financial statements, the Company (i) follows the full cost method of accounting for the costs of its oil and gas properties, (ii) amortizes such costs using the units of production method, and (iii) applies a quarterly full cost ceiling test. Adverse changes in 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.

Estimates of Proved Oil and Gas Reserves. 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.

Estimates of Asset Retirement Obligations. In accordance with SFAS No 143, we make estimates of future costs and the timing thereof in connection with recording our future obligations to plug and abandon wells. Estimated abandonment dates will be revised in the future based on changes to related economic lives, which vary with product prices and production costs. Estimated plugging costs may also be adjusted to reflect changing industry experience. Increases in operating costs and decreases in product prices would increase the estimated amount of the obligation and increase DD&A expense. Cash flows would not be affected until costs to plug and abandon were actually incurred.

Fair value of debt and equity transactions. Many of our various debt and equity transactions require us to determine the fair value of a debt or equity instrument in order to properly record the transaction in our financial statements. We have not utilized independent third parties to assist us in determining the fair value of many of our transactions. Fair value is generally determined by applying widely acceptable valuation models, (e.g., the Black-Scholes options valuation model) using the trading price of the underlying instrument or by comparison to instruments with comparable maturities and terms.

New Accounting Pronouncements. In December 2004, the FASB issued Statement of Financial Accounting Standards No. 123R "Shared Based Payment" ("SFAS 123R"). This statement is a revision of SFAS Statement No. 123 "Accounting for Stock-Based Compensation" and supersedes APB Opinion No. 25, "Accounting for Stock Issued to Employees," and its related implementation guidance. SFAS 123R addresses all forms of shared based compensation ("SBP") awards, including shares issued under employee stock purchase plans, stock options, restricted stock and stock appreciation rights. Under SFAS 123R, SBP awards result in a cost that will be measured at fair value on the awards' grant date, based on the estimated number of awards that are expected to vest and will be reflected as compensation cost in the historical financial statements. This statement is effective for public entities that file as small business issuers as of the beginning of the first interim or annual reporting period that begins after December 15, 2005. The Company plans to adopt SFAS No. 123R on July 1, 2006 and we estimate that our stock compensation cost will increase by a material amount. However, due to the non-cash nature of this charge, adoption of SFAS No. 123R will have no impact on our cash position.

On March 29, 2005, the SEC released Staff Accounting Bulletin 107 ("SAB 107"), providing additional guidance in applying the provisions of SFAS 123(R). SAB 107 should be applied when adopting SFAS 123(R) and addresses a wide range of issues, focusing on valuation methodologies and the selection of assumptions. In addition, SAB 107 addresses the interaction of SFAS 123(R) with existing SEC guidance.

On September 13, 2006, the SEC released Staff Accounting Bulletin 108 ("SAB 108") providing interpretive guidance on how the effects of the carryover or reversal of prior year misstatements should be considered in quantifying a current year misstatement. There have been two common approaches used to quantify such errors. Under one approach, the error is quantified as the amount by which the current year income statement is misstated. The other common approach quantifies the error as the cumulative amount by which the current year balance sheet is misstated. Exclusive reliance on an income statement approach can result in a registrant accumulating errors on the balance sheet that may not have been material to any individual income statement, but which nonetheless, may misstate one or more balance sheet accounts. Similarly, exclusive reliance on a balance sheet approach can result in a registrant disregarding the effects of errors in the current year income statement that result from the correction of an error existing in previously issued financial statements. The SEC staff believes that registrants should quantify errors using both a balance sheet and an income statement approach and evaluate whether either approach results in quantifying a misstatement that, when all relevant quantitative and qualitative factors are considered, is material.

This Form 10-KSB includes certain statements that may be deemed to be "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements included in this Form 10-KSB, other than statements of historical facts, address matters that the Company reasonably expects, believes or anticipates will or may occur in the future. Such statements are subject to various assumptions, risks and uncertainties, many of which are beyond the control of the Company. Investors are cautioned that any such statements are not guarantees of future performance and actual results or developments may differ materially from those described in the forward-looking statements. The Company bases its forward-looking statements on information currently available and it undertakes no obligation to update them.

Item 7. Financial Statements.

Index to Consolidated Financial Statements

Evolution Petroleum Corporation and Subsidiaries
Consolidated Balance Sheets

	June 30, 2006	June 30, 2005
Assets		
Current Assets:		
Cash	$ 9,893,547	$ 2,548,688
Accounts receivable, trade	132,371	300,761
Inventories	76,917	222,470
Prepaid expenses	157,629	84,304
Retainers and deposits	60,895	56,335
Total current assets	10,321,359	3,212,558
Cash in qualified intermediary account for "like-kind" exchanges	34,662,368	0
Oil & Gas properties - full cost	3,878,551	5,276,303
Oil & Gas properties - not amortized	52,098	61,887
Less: accumulated depletion	(371,624)	(313,391)
Net oil & gas properties	3,559,025	5,024,799
Furniture, fixtures and equipment, at cost	16,561	12,113
Less: accumulated depreciation	(7,998)	(3,401)
Net furniture, fixtures, and equipment	8,563	8,712
Restricted deposits	326,835	863,089
Other assets	79,808	356,066
Total assets	$48,957,958	$ 9,465,224
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$ 310,272	$ 240,389
Accrued liabilities	473,782	276,470
Notes payable, current	0	6,754
Income taxes payable	2,978,650	0
Royalties payable	47,054	89,713
Total current liabilities	3,809,758	613,326
Long term liabilities:		
Notes Payable, net of discount	0	2,906,548
Deferred income taxes payable	13,101,350	0
Asset retirement obligations	123,679	433,250
Total liabilities	17,034,787	3,953,124
Common Stock, totaling 351,333 shares subject to demand registration rights	790,500	0
Stockholders' equity:		
Common Stock, par value $0.001 per share; 100,000,000 shares authorized, 26,300,664 and 24,774,606, issued and outstanding as of June 30, 2006 and June 30, 2005, respectively, net of 351,333 shares of common stock subject to demand registration rights	26,300	24,774
Additional paid-in capital	10,274,555	9,611,767
Deferred stock based compensation	(265,167)	(595,283)
Accumulated income / (deficit)	21,096,983	(3,529,158)
Total stockholders' equity	31,132,671	5,512,100
Total liabilities and stockholders' equity	$48,957,958	$ 9,465,224

See accompanying notes to consolidated financial statements.

Evolution Petroleum Corporation and Subsidiaries
Consolidated Statements of Operations

	Years Ended June 30, 2006	2005
Revenues:		
Oil sales	$ 2,450,676	$ 1,335,288
Gas sales	424,190	358,433
Price risk management activities	(13,452)	(58,534)
Total revenues	2,861,414	1,635,187
Operating Costs:		
Production expenses	1,725,760	874,876
Production taxes	86,562	68,386
Depreciation, depletion and amortization	407,467	260,124
General and administrative (includes non-cash stock based compensation expense of $546,567 and $707,117 for the years ended June 30, 2006 and 2005)	2,826,085	2,220,780
Total operating costs	5,045,874	3,424,166
Loss from operations	(2,184,460)	(1,788,979)
Other income and (expense):		
Interest income	165,313	11,709
Interest expense	(2,600,180)	(387,301)
Gain on sale of assets	45,325,468	0
Total other income and (expense)	42,890,601	(375,592)
Income / (loss) before income taxes	40,706,141	(2,164,571)
Income tax expense:		
Current	2,978,650	0
Deferred	13,101,350	0
Total income tax expense	16,080,000	0
Net income (loss)	$24,626,141	$(2,164,571)
Earnings/ (Loss) per common share		
Basic	$ 0.98	$ (0.09)
Diluted	$ 0.96	$ (0.09)
Weighted average number of common share		
Basic	25,031,125	23,533,922
Diluted	25,555,992	23,533,922

See accompanying notes to consolidated financial statements.

Evolution Petroleum Corporation and Subsidiaries
Consolidated Statements of Cash Flow

	Twelve Months Ended June 30, 2006	Twelve Months Ended June 30, 2005
Cash flows from operating activities:		
Net Income / (loss)	$ 24,626,141	$(2,164,571)
Adjustments to reconcile net income / (loss) to net cash used by operating activities:		
Gain on asset sale	(45,208,532)	0
Depletion	402,870	257,882
Depreciation	4,597	2,242
Non-cash stock based compensation expense	546,567	707,117
Amortization of deferred financing costs	293,797	0
Accretion of asset retirement obligations	27,716	21,824
Accretion of debt discount and non-cash loan costs	1,739,046	78,882
Non-cash penalty expense	240,000	0
Changes in assets and liabilities:		
Accounts receivable	168,390	(276,374)
Retainer and deposits	(4,560)	0
Inventories	145,553	(106,611)
Accounts payable	69,883	101,201
Royalties payable	(42,659)	89,713
Accrued liabilities	247,312	226,397
Income taxes payable	16,080,000	0
Prepaid expenses	(73,325)	(15,237)
Net cash used by operating activities	(737,204)	(1,077,535)
Cash flows from investing activities:		
Development of oil and gas properties	(2,611,369)	(503,394)
Acquisitions of oil and gas properties	(1,448,239)	(1,554,149)
Proceeds from asset sale	49,993,134	0
Cash in qualified intermediary account for "like-kind" exchanges	(34,662,368)	0
Capital expenditures for furniture, fixtures and equipment	(4,448)	(9,022)
Restricted deposits	536,254	(612,589)
Other assets	19,661	(99,469)
Net cash provided (used) in investing activities	11,822,625	(2,778,623)
Cash flow from financing activities:		
Payments on notes payable	(5,634,654)	(1,725,167)
Proceeds from notes payable	1,040,764	3,806,678
Deferred financing costs	(37,201)	(279,924)
Proceeds from issuance of common stock and fair value of warrants issued with debt	999,385	4,729,091
Transaction & registration costs	(108,856)	(493,663)
Net cash provided (used) by financing activities	(3,740,562)	6,037,015
Net increase in cash and cash equivalents	7,344,859	2,180,857
Cash and cash equivalents, beginning of period	2,548,688	367,831
Cash and cash equivalents, end of period	$ 9,893,547	$ 2,548,688
Supplemental disclosure of cash flow information:		
Interest paid	$ 567,273	$ 308,419
Income taxes paid	$ 0	$ 0
Non-cash transactions:		
Non-cash equity adjustment	$ 50,000	$ 0
Assumption of asset retirement obligations	$ 0	$ 99,984

See accompanying notes to consolidated financial statements.

Evolution Petroleum Corporation and Subsidiaries
Consolidated Statements of Changes in Stockholders' Equity
For the twelve months ended June 30, 2006 and June 30, 2005

	Shares	Dollars	Additional Paid-in Capital	Deferred Stock Based Compensation	Accumulated Income / (Deficit)	Total Stockholders' Equity
Balances, June 30, 2004	22,945,406	22,945	4,453,905	(378,136)	(1,364,587)	2,734,127
Sales of common stock	1,829,200	1,829	4,502,517	--	--	4,504,346
Fair value of warrants issued with debt	--	--	1,149,008	--	--	1,149,008
Transaction and registration costs	--	--	(493,663)	--	--	(493,663)
Deferred compensation	--	--	--	(217,147)	--	(217,147)
Net loss	--	--	--	--	(2,164,571)	(2,164,571)
Balances, 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	599,327	599	1,005,073	--	--	1,005,672
Reduction of capital related to common stock, subject to demand registration rights	(351,333)	(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
Deferred compensation	--	--	--	330,116	--	330,116
Net Income	--	--	--	--	24,626,141	24,626,141
Balances, June 30, 2006	26,300,664	$26,300	10,274,555	($265,167)	21,096,983	$31,132,671

See accompanying notes to consolidated financial statements.

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Company's Business

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. During the two years prior to May 26, 2004, Reality represented that it had not conducted any operations and had minimal assets and liabilities.

On May 26, 2004, Natural Gas Systems, Inc., a privately owned Delaware corporation formed in September of 2003 (" Old NGS "), was merged into a wholly owned subsidiary of Reality and Reality changed its name to Natural Gas Systems, Inc. On the effective date of the merger, Laird Q. Cagan was elected as Chairman of the Board of Directors of Reality and Robert S. Herlin and Sterling H. McDonald, the CEO and CFO of Old NGS, were elected CEO and CFO of Reality, respectively. The corporation was renamed Natural Gas Systems, Inc. ("we", "us", "our", "our company", "Company" or "NGS") and adopted a June 30 fiscal year end.

Natural Gas Systems, Inc changed its name to "Evolution Petroleum Corporation" (AMEX: EPM) effective July 11, 2006, to avoid potential confusion with similar names traded on the AMEX and to better reflect our business model. The change was effected pursuant to an Agreement and Plan of Merger dated as of July 11, 2006 by which Evolution Petroleum Corporation, a Nevada corporation and wholly-owned subsidiary of the Company, merged with and into the Company, with the Company as the surviving entity and renamed as "Evolution Petroleum Corporation." This statutory short-form merger and name change was effectuated without shareholder approval in accordance with the provisions of Section 92A.180 of the Nevada Revised Statutes. The Company's Board of Directors authorized this transaction on June 26, 2006.

Headquartered in Houston, Texas, Evolution Petroleum Corporation is a petroleum company 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. At June 30, 2006, we conducted our operations through our 100% working interest in the Tullos Urania field, Crossroads field and Colgrade fields (collectively, the "Tullos Field Area"), and our non-operated royalty, overriding royalty and back-in working interests in the Delhi Field, all located in Louisiana.

All regulatory filings and other historical information prior to May 26, 2004 apply to Reality, the predecessor of the Company. EPM trades on the American Stock Exchange under the symbol "EPM".

2. Significant Risks and Uncertainties

Preparation of our financial statements requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities and contingencies as of the balance sheet date, and the reported amount of revenues and expenses during the reporting period. On an ongoing basis, management reviews its estimates, including those related to litigation, environmental liabilities, income taxes, abandonment costs and the determination of proved reserves. Changes in circumstances may result in revised estimates and actual results may differ from those estimates.

Our business makes us vulnerable to changes in crude oil and natural gas prices. Such prices have been volatile in the past and can be expected to be volatile in the future. This volatility can dramatically affect cash flows and proved reserves, since price declines reduce the estimated quantity of proved reserves and increase annual amortization expense (which is based on proved reserves), or could potentially result in an impairment charge. Other risks related to proved reserves, revenues, and cash flows include our current reliance on the concentration of a few wells.

3. Summary of Significant Accounting Policies

Principles of Consolidation -- Our consolidated financial statements include the Company and its subsidiaries. All material inter-company accounts and transactions have been eliminated.

Oil and Gas Properties and Furniture, Fixtures and Equipment -- We follow the full cost method of accounting for its 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 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.

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.

Equipment, which includes computer equipment, hardware and software and furniture and fixtures, is recorded at cost and is generally depreciated on a straight-line basis over the estimated useful lives of the assets, which range from two to five years.

Repairs and maintenance are charged to expense as incurred.

Statement of Cash Flows -- For purposes of the statements of cash flows, cash equivalents include highly liquid financial instruments with maturities of three months or less as of the date of purchase.

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, 2006.

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

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, 2006 and 2005, the valuation allowance was $0.

Inventory - Inventory, which is included in current assets, 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 Options --SFAS 123, "Accounting for Stock-Based Compensation," as amended by SFAS 148, "Accounting for Stock-Based Compensation--Transition and Disclosure," established accounting and disclosure requirements using a fair value-based method of accounting for stock-based employee compensation plans. We account for stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board Opinion 25, "Accounting for Stock Issued to Employees" ("APB 25").

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. The fair value of the notes payable to Prospect Energy approximates the carrying value of the notes as the effective interest rates applicable to the notes approximates current rates available to us for comparable financing arrangements.

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 as an asset or liability measured at fair value and requires that the changes in the fair value be recognized currently in our earnings unless specific hedge accounting criteria is met.

Upon adoption, we did not have any financial derivative contracts utilized for non-trading purposes. Thus, the adoption of SFAS No. 133 had no impact on us. We have entered into certain over-the-counter contracts to hedge the cash flow of part of our forecasted sale of oil and gas production. We did not elect to document and designate these as hedges. Thus, the changes in the fair value of these over-the-counter contracts are reflected in the 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 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.

Earning (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 - In December 2004, the FASB issued Statement of Financial Accounting Standards No. 123R "Shared Based Payment" ("SFAS 123R"). This statement is a revision of SFAS Statement No. 123 "Accounting for Stock-Based Compensation" and supersedes APB Opinion No. 25, "Accounting for Stock Issued to Employees," and its related implementation guidance. SFAS 123R addresses all forms of shared based compensation ("SBP") awards, including shares issued under employee stock purchase plans, stock options, restricted stock and stock appreciation rights. Under SFAS 123R, SBP awards result in a cost that will be measured at fair value on the awards' grant date, based on the estimated number of awards that are expected to vest and will be reflected as compensation cost in the historical financial statements. This statement is effective for public entities that file as small business issuers as of the beginning of the first annual reporting period that begins after December 15, 2005. The Company plans to adopt SFAS No. 123R on July 1, 2006 and we estimate that our stock compensation cost will increase by a material amount; however due to the non-cash nature of this charge, adoption of SFAS No. 123R will have no impact on our cash position.

On March 29, 2005, the SEC released Staff Accounting Bulletin 107 ("SAB 107") providing additional guidance in applying the provisions of SFAS 123(R). SAB 107 should be applied when adopting SFAS 123(R) and addresses a wide range of issues, focusing on valuation methodologies and the selection of assumptions. In addition, SAB 107 addresses the interaction of SFAS 123(R) with existing SEC guidance.

4. Acquisitions and Divestitures

On January 31, 2006, we acquired from an unrelated third party an overriding royalty interest of 4.811195% in the Delhi Holt Bryant Unit ("Delhi Unit") within the Delhi Field. Funding of the $1.0 million purchase price was provided by an additional $1.0 million advance under our Prospect Facility, thereby increasing the maturity value of our note due at maturity to $6.0 million, and the issuance of an additional 150,000 of irrevocable warrants and 100,000 of revocable warrants, exercisable over five years at the 20 trading day average price immediately prior to January 31 2006. The Prospect facility was repaid in full on May 31, 2006. See Note 7 for more about the repayment of the Facility.

In June 2006, we acquired from various unrelated third parties, additional royalty and overriding royalty interests totaling 2.2048% in the Delhi Holt Bryant Unit. Funding of the approximate $464,000 purchase price was provided by the approximate $50 million in proceeds received from the sale of our working interest in the Delhi Field to a subsidiary of Denbury Resources Inc. See below for more about the divestiture.

Also in June 2006, another unrelated party agreed to sell us their royalty and overriding royalty interests aggregating 0.38919% in the Delhi Holt Bryant Unit for approximately $85,000. The closing of this acquisition occurred on July 21, 2006. Funding was provided by the proceeds from the asset sale mentioned above.

Acquisitions were recorded using the purchase method of accounting and, accordingly, results of operations of these acquired activities and oil and gas properties have been included in our results of operations from the respective closing dates of the acquisitions.

As previously reported in a Current Report on Form 8-K filed by the Company with the SEC on May 11 and June 16, 2006, we conveyed a farmout to Denbury Onshore, LLC., a subsidiary of Denbury Resources, Inc. (NYSE: DNR, hereinafter referred to as "Denbury" or "DNR") to conduct a CO_2 enhanced oil recovery project in the Delhi Holt Bryant Unit within the Delhi Field in northeast Louisiana (the "Delhi Farmout"). On June 12, 2006, we received $50 million and delivered to Denbury all of our working interests and an 80% net revenue interest in the Delhi Holt Bryant Unit, and a 75% working interest and a 60% net revenue interest in certain other depths in the Delhi Field. We retained 7.4% in separately acquired royalty and overriding royalty interests in the Delhi Holt Bryant Unit as discussed above and a 25% working interest (20% net revenue interest) in certain other depths of the Delhi Field outside of the Delhi Holt Bryant Unit. Under the terms of the Delhi Farmout, Denbury has agreed to contribute all development capital, technical expertise and required amounts of proven reserves of carbon dioxide that will be injected into the Delhi Holt Bryant Unit oil reservoirs. After the project generates $200 million of net cash flows before capital expenditures for Denbury, we will regain a 25% working interest (20% net revenue interest) in the Delhi Holt Bryant Unit.

5. Asset Retirement Obligations

Asset retirement obligations are included in long term liabilities on our balance sheet. The following table describes the change in our asset retirement obligations for the periods from June 30, 2005 to June 30, 2006:

Asset retirement obligation at June 30, 2005	$ 433,250
Liabilities incurred	0
Accretion expense for 2006	27,716
Revisions to estimates during 2006 (property divestiture)	(337,287)
Asset retirement obligation at June 30, 2006	$ 123,679

On June 12, 2006, we closed the Delhi Farmout. Consequently, once the change of operator has been filed by the new operator with the State of Louisiana and they establish their own Site Specific Trust Account, we will seek release of our collateralized certificate of deposit from the State and receive a refund of approximately $326,000.

6. Oil and Gas Properties

Depletion expense for the twelve months ended June 30, 2006 and June 30, 2005 totaled $402,870 and $257,882, respectively. Also, as of June 30, 2006 and 2005, unamortized capital expenditures totaled $52,098 and $61,887, respectively.

These costs are reviewed quarterly to determine when they should be transferred to the full cost pool and amortized.

7. Notes Payable

The following table sets forth the Company's notes payable balances as of the dates indicated:

Borrowing	June 30, 2006	June 30, 2005
Cananwill Insurance Premium Loan	--	6,754
Prospect Energy Note	--	2,906,548
Total Outstanding	$--	$2,913,302

CANANWILL LOAN: At June 30, 2005, $6,754 was owed under the Cananwill Insurance Premium Loan. The balance of $6,754 was paid in October 2006.

LOAN: In March 2006, Laird Q. Cagan, our Chairman and a major stockholder, loaned us $250,000 pursuant to an unsecured note bearing interest at 10% per annum. The funds were used for corporate and working capital purposes. On June 12, 2006, we repaid the Loan, totaling $257,058 with accrued interest, in full.

PROSPECT ENERGY NOTE: On February 3, 2005, we closed the "Prospect Facility" (or "Facility") and drew down $3,000,000, and on March 16, 2005 we drew down an additional $1,000,000 against a $4,800,000 total commitment. The draws were used to fund the February 2005 acquisition of properties in Louisiana, costs of the financing, funding of a debt service reserve fund, repayment of a bridge loan, immediate re-development of our existing properties and for working capital purposes.

At June 30, 2005, we owed $2,906,548 on the Prospect Facility, including the accreted discount through such date. At maturity or, exclusive of any prepayment penalty, on early prepayment, the total amount owed under the Facility was $4,000,000 due to accretion of the original issue discount.

During fiscal year 2006, we borrowed another $1,000,000 in maturity value of loans from Prospect to fund the acquisition of an overriding royalty interest in the Delhi Holt Bryant Unit, recording approximately $0.8 million of the proceeds to loans payable and $0.2 million of the proceeds to equity from the warrants we attached. On May 31, 2006, we voluntarily repaid the Prospect loan in full, including a prepayment penalty, offset by release of $0.56MM held in a restricted Debt Service Reserve account.

8. Common Stock, Stock Options and Warrants

Common Stock

During the twelve months 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 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 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.

During the twelve months ended June 30, 2005, we raised gross proceeds of $4,729,091 from the sale of our common stock, warrants to purchase our common stock and direct stock grants, less placement fees of $257,840 paid to Chadbourn Securities and Laird Q. Cagan and warrants to purchase 108,536 shares. In addition, we also paid $32,659 to unrelated third parties as finder's fees. Of the total, $3,580,083 was received from the sale of 1,594,200 shares of our common stock and the issuance of 235,000 shares of our common stock upon the exercise of options and direct stock awards granted under our 2004 Stock Plan. The remaining $1,149,008 was raised through the sale of warrants to Prospect Energy.

Options and Warrants issued to Employees

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, giving rise to $437,250 of expense, spread over a four year vesting schedule.

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 months 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

During the twelve months 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 and Mr. McDonald was awarded warrants to purchase 150,000 shares. These warrants were granted at "at the money" on the grant date and have a four year vesting term and a contractual life of 10 years.

A reconciliation of reported income (loss) as if the Company used the fair value method of accounting for stock-based compensation computed under FASB 123 as compared to the compensation expense we recorded under APB 25 follows:

	Twelve Months ended June 30, 2006	Twelve Months ended June 30, 2005
Net income / (loss) attributable to common stockholders, as reported	$ 24,626,141	($2,164,571)
Plus: share based compensation expense determined under APB 25	171,537	131,313
Less: compensation expense determined under Fair Value Method	(1,543,690)	(359,457)
Pro forma net income / (loss) attributable to common stockholders	$ 23,253,988	($2,392,715)
Basic earnings / (loss) per common share:		
As reported	$0.98	($0.09)
Pro Forma	$0.93	($0.10)
Diluted earnings / (loss) per common share:		
As reported	$0.96	($0.09)
Pro Forma	$0.91	($0.10)
Weighted average Black-Scholes fair value assumptions:		
Risk free interest rate	4.18% - 4.93%	4.18% - 4.93%
Expected life	2-4 years	3-4 years
Expected volatility	104% - 159%	104% - 130%
Expected dividend yield	0.0%	0.0%

Fair values were estimated at the date of grant using the Black-Scholes options pricing model, based on the assumptions above. For purposes of the pro forma disclosures, the estimated fair value is amortized to expense over the awards' vesting period. The Black-Scholes option valuation model was developed for use in estimating the fair value of traded options which have no vesting restrictions and are fully transferable. In addition, option valuation models require the input of highly subjective assumptions including the expected stock price volatility. Because the Company's employee stock options have characteristics significantly different from those of traded options, and because changes in the subjective input assumptions can materially affect the fair value estimate, in management's opinion, the existing models do not necessarily provide a single measure of the fair value of its employee stock options. At June 30, 2006, 1,494,000 shares were available for grant under the plans.

A summary of option and warrant transactions issued to employees for the period from July 1, 2004 to June 30, 2006 follows:

	Number of Shares	Weighted average Exercise Price	Weighted average Grants Date Fair Value	Weighted average Remaining Contractual Life
Beginning balance	500,000	$0.13		9.3 years
Twelve months ended June 30, 2005				
Granted	2,012,500	$1.71	$1.31	
Exercised				
Canceled				
Outstanding at June 30, 2005	2,512,500	$1.39		9.4 years
Twelve months ended June 30, 2006				
Granted	1,311,000	$1.70	$1.43	
Exercised				
Canceled				
Outstanding at June 30, 2006	3,823,500	$1.50		9.6 years

These options and warrants vest during the following fiscal years ended as follows: Vested at June 30, 2005: 303,125; 2006: 1,001,250; 2007: 935,375; 2008: 801,250; 2009: 641,875 and 2010: 140,625.

Options, Warrants and Grants to Non-Employees

At June 30, 2006, outstanding warrants and options, excluding employees, to purchase the Company's common shares were as follows:

	Warrants and Stock Options Outstanding (excludes employees)			
Holders	Range of Exercisable Prices		Outstanding at June 30, 2006	Exercisable at June 30, 2006
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	79,444
Others	$ 1.00	$2.00	94,750	94,750
Total			550,521	519,965

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 gives 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 our 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, which was $15,000 per month through October 2005 and $5,000 per month beginning December 1, 2005, per the amended agreement. 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 $1MM of gross proceeds to a minimum rate of 4%, and warrants equal to 4% of the shares placed by CMCP.

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 substantial portion of which we believe 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.

During the fiscal year ended June 30, 2005, we issued warrants to purchase 91,359 and 5,427 shares of common stock to Laird Q. Cagan and Chadbourn Securities, Inc., respectively, in connection with capital raising services. During the same period, we paid $257,890 cash commissions to Laird Q. Cagan and Chadbourn Securities, Inc., in connection with capital raising activities. Further, during fiscal year ended June 30, 2005, the Company expensed and paid CMCP $180,000 for monthly retainers earned in fiscal 2005, and paid $60,000 for monthly retainers earned, but unpaid, during fiscal 2004.

Also during fiscal 2005, from August through December, 2004, Mr. Cagan loaned us, through a series of advances, $920,000, pursuant to a secured promissory note bearing interest at 10% per annum and a 5% origination fee (the "Bridge Loan") earmarked for our purchase of working interests in the Tullos Urania Field in Louisiana, working capital and certain costs related to the pre-closing of the Prospect Facility. On February 15, 2005, we repaid the Bridge Loan, totaling $953,589 with accrued interest, in full.

10. Supplemental Disclosures about Oil and Gas Producing Properties

Net Capitalized Costs

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

	Twelve Months Ended June 30, 2006	Twelve Months Ended June 30, 2005
Capitalized costs being amortized	$3,878,551	$5,276,303
Capitalized costs not being amortized*	52,098	61,887
Total	3,930,649	5,338,190
Less accumulated depletion	(371,624)	(313,391)
Net capitalized costs	$3,559,025	$5,024,799

* Costs not being amortized at the end of each period were excluded from the depletion base. The costs as of June 30, 2006 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:

	Twelve Months Ended June 30, 2006	Twelve Months Ended June 30, 2005
Property acquisition costs:		
Proved	$1,448,239	$1,554,149
P&A liability assumed	--	99,984
Unproved	(9,788)	61,887
Exploration costs	--	--
Development costs	2,611,369	441,508
Total	$4,049,820	$2,157,528

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 2006 and 2005. 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.

	Twelve Months Ended June 30, 2006	Twelve Months Ended June 30, 2005
Oil and gas sales	$ 2,861,414	$1,635,187
Production expenses	(1,725,760)	(874,876)
Production taxes	(86,562)	(68,386)
Depletion	(402,870)	(257,882)
Results of operations for oil and gas producing activities (excluding corporate overhead and financing costs)	$ 646,222	$ 434,043

Oil and Gas Reserve Quantities (unaudited)

The following table sets forth the net proved reserves of the Company as of July 1, 2006, and the changes therein for the periods from July 1, 2004 to July 1, 2006. 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)
July 1, 2004	239,534	508,556
Purchases of minerals in place (1)	418,217	0
Extensions and discoveries	242,340	330,023
Revisions	(100,978)	(34,290)
Production	(27,230)	(72,166)
Sales of minerals in place	0	0
July 1, 2005 (2)	771,883	732,123
Purchases of minerals in place	4,200	25,800
Extensions and discoveries	0	0
Revisions	138,762	0
Production	(46,942)	(45,368)
Sales of minerals in place	(407,403)	(686,755)
July 1, 2006	460,500	25,800
Proved developed reserves:		
July 1, 2004(3)	239,534	508,556
July 1, 2005(4)	540,360	396,600
July 1, 2006(5)	460,500	25,800

(1) Proved developed reserves acquired in the Tullos Field Area during fiscal 2005.

(2) During fiscal 2005, the preponderance of our proved crude oil and natural gas extensions and discoveries was due to the addition of eight proved undeveloped reserve locations (PUDs), resulting from a six month geological study performed by an outside geologist we engaged to review approximately 20% of our Delhi Field. Proved crude oil additions more than exceeded the downgrade of our acquired Tullos reserves, resulting from poor performance related to bad weather, lack of service equipment and lack of repairs and maintenance by the seller in the months immediately preceding our acquisition. Elimination of our Delhi 210-2 well was primarily offset by a decrease in the estimate of fuel use. Proved natural gas reserve quantities include 7,300 Bbl of NGL's, converted at 6 Mcfs per Bbl at July 1, 2005.

(3) At July 1, 2004, our proved developed natural gas reserves include 5,000 Bbls of NGL, converted at 6 Mcfs per Bbl.

(4) During fiscal 2005, our proved developed natural gas reserves were revised downward due to the loss of our Delhi 210-2 well due to bad casing. At July 1, 2005, our proved developed natural gas reserves included 3,500 Bbls of NGL, converted at 6 Mcf per Bbl.

(5) 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.

Standardized Measure of Discounted Future Net Cash Flows at June 30, 2006 and June 30, 2005

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.

	June 30, 2006	June 30, 2005
Future cash inflows	$ 32,874,568	$ 46,841,246
Future production costs	(18,167,012)	(20,028,389)
Future development costs	(566,000)	(1,920,000)
Future income taxes	(2,687,000)	(6,036,000)
Future net cash flows	$ 11,454,556	$ 18,856,857
10% annual discount	(4,943,196)	(5,615,779)
Standardized Measure	$ 6,511,360	$ 13,241,078

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 twelve months ended June 30, 2006 and 2005:

	Twelve Months Ended June 30, 2006	Twelve Months Ended June 30, 2005
Standardized Measure, beginning	$ 13,241,078	$ 5,180,611
Net changes in income taxes	1,445,256	(3,209,706)
Oil and gas sales, net of costs	(1,049,092)	(691,925)
Discoveries, extensions and transfers	239,382	7,131,907
Purchase of minerals in place	354,679	4,780,920
Sale of minerals in place	(12,916,340)	0
Changes in prices and costs	1,403,539	3,285,724
Change in development costs	1,116,590	(1,045,275)
Accretion discount	1,324,108	518,061
Revisions of estimates	1,352,160	(2,670,979)
Other	0	(38,260)
Standardized Measure, ending	$ 6,511,360	$ 13,241,078

11. Restricted Deposits

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 $227,000 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. Treasury and Agency Money Market Fund with short-term durations.

At June 30, 2005, Restricted Deposits include $301,835 to secure a letter of credit posted with the State of Louisiana for future plugging and abandonment liabilities related to the Delhi Field, and $560,000 to secure the debt service reserve under the Prospect Facility. Approximately $202,000 exceeds FDIC insurance limits in depository accounts at Wells Fargo bank.

12. Income Taxes

The tax effect of significant temporary differences representing deferred tax assets and liabilities at June 30, 2006 and 2005 are as follows:

	2006	2005
Oil and gas properties	($964,000)	($178,000)
Basis in subsidiary stock	149,000	126,000
Other	95,650	(11,000)
Gain on sale of property	(12,191,000)	0
Net operating loss carryforwards	6,390,000	6,325,000
Valuation allowance	(6,581,000)	(6,262,000)
Net deferred tax asset / (liability)	($13,101,350)	$ 0

At June 30, 2006, we have current income tax payable of $2.98 million (split $2.3 million for federal income taxes and $0.6 million for state income taxes due) and a deferred non-current tax liability of approximately $13.1 million, primarily as a result of the Delhi Farmout in which we received approximately $50 million of pre-tax proceeds. In determining the $16.1 million of current and non-current deferred tax liability, we used all of our $2.8 million of NOL's generated by our oil and gas operations, and $82,600 of pre-merger Reality NOL's.

We have established a full valuation allowance against our net deferred tax assets totaling $6.58 million for fiscal year ended 2006, and we will continue to take a full valuation allowance until an appropriate level of profitability is attained. Of this amount, $6.1 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 under advice from our tax consultants and in concert with our analysis of the Internal Revenue Code, including Rev. Proc. 77-176, IRC Section 614 property definitions pertaining to natural resources, the IRS training manual regarding the designation of property classifications with respect to natural resources, General Counsel Memorandums 33552, 24094, 22106, various court case rulings and other applicable research.

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 purchase 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 placed $35 million in a qualified intermediary ("QI") account for possible Internal Revenue Code 1031 "like-kind exchanges" (which is 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 is 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. On or prior to 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). In the event that we choose to withdraw any funds from the qualified intermediary account to fund non like-kind exchanges, or if we fail to use all of the funds for like-kind exchanges prior to December 9, 2006, all of the funds remaining or disbursed from the QI account will become subject to immediate taxable gain on the sale of the Delhi property.

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

	2006	2005
Income taxes (benefit) at U.S. and state statutory rates	$ 16,400,000	($735,954)
Non-deductible amortization and expenses	0	0
Non-deductible interest expense and deferred stock compensation	508,000	240,860
Deferred tax asset valuation allowance adjustment	(1,160,000)	495,094
Other	332,000	0
Total	$ 16,080,000	$ 0

The U. S. statutory rate is 35%. The state of Louisiana tax rate, net of federal tax benefit is 5.2%. The blended tax rate is 40.2%

The deferred tax asset valuation allowance adjustment is due to the release of valuation allowances from prior year NOL's, including net operating losses from that past two fiscal years and the maximum portion of tax credits allowed under current tax laws for Reality's NOL's. The total amount of the NOL's used in the current year is $2.9 million, with a tax effect of approximately $1,160,000.

13. Leases

At June 30, 2006, our only operating lease obligation is for our corporate headquarters in Houston, Texas. Minimum lease payments (i.e. rent expense) through April 14, 2007, the expiration date of agreement, totals $33,980.

Our lease expense was $121,502 for the twelve months ended June 30, 2006 and $121,799 for the twelve months ended June 30, 2005. These figures include a monthly lease rental for the gas processing plant servicing our Delhi Field, which was terminated on June 1, 2006, the effective date of our Delhi Farmout.

14. Earnings / (Loss) per Share

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

	Twelve Months ended June 30, 2006	Twelve Months ended June 30, 2005
Numerator:		
Net income / (loss) applicable to common stockholders	$24,626,141	($2,164,571)
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	$24,626,141	($2,164,571)
Denominator:	25,031,125	23,533,922
Affect of potentially dilutive common shares:		
Warrants	176,072	N/A
Employee and director stock options	348,795	N/A
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	25,555,992	23,533,922
Earnings / (loss) per common share:		
Basic	$ 0.98	($0.09)
Diluted	$ 0.96	($0.09)

15. 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, two of these contracts continue to extend through February 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.

16. Major Customers

All of our crude oil is currently sold to Plains Marketing L.P. and committed through the life of our fixed price crude oil sales contract. Other crude oil purchasers are available.

17. Subsequent Events

Natural Gas Systems, Inc changed its name to "Evolution Petroleum Corporation" effective July 11, 2006. Our name was changed pursuant to an Agreement and Plan of Merger dated as of July 11, 2006 by which Evolution Petroleum Corporation, a Nevada corporation and wholly-owned subsidiary of the Company, merged with and into the Company, with the Company as the surviving entity and renamed as "Evolution Petroleum Corporation." This statutory short-form merger and name change was effectuated without shareholder approval in accordance with the provisions of Section 92A.180 of the Nevada Revised Statutes. Our Board of Directors authorized this transaction on June 26 2006.

On July 17, 2006, our common stock began trading on the American Stock Exchange ("AMEX") under the ticker symbol "EPM." J. Streicher & Co. Ltd acts as our trading specialist.

On July 21, 2006, we funded and closed the acquisition of 0.39% in royalty and overriding royalty interests in the Delhi Holt Bryant Unit from an unrelated third party owner.

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, 2006 and 2005 and the related consolidated statements of operations, stockholders' equity, and cash flows for the years ended June 30, 2006 and 2005. 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, 2006 and 2005, 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.

HEIN & ASSOCIATES LLP

Houston, Texas
August 29, 2006

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 e 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's 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; 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 2006 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 2006 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 2006 fiscal year.

Item 12. Certain Relationships and Related Transactions.

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 2006 fiscal year.

Item 13. Exhibits.

Index of Exhibits

2.1	Asset Purchase Agreement for Tullos Field, dated September 3, 2004.	Previously Filed
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
3(i)	Articles of Incorporation.	Previously Filed
3(ii)	Bylaws.	Previously Filed
10.1	Registration Rights Agreement, dated as of February 2, 2005, between the Company and Prospect	Previously Filed
10.2	Executive Employment Agreement, Robert S. Herlin, dated April 4, 2005	Previously Filed
10.3	Herlin Stock Option Agreement, dated April 4, 2005	Previously Filed
10.4	Herlin Warrant Agreement, dated April 4, 2005	Previously Filed
10.5	Executive Employment Agreement, Sterling H. McDonald, dated April 4, 2005	Previously Filed
10.6	McDonald Stock Option Agreement, dated April 4, 2005	Previously Filed
10.7	Securities Purchase Agreement dated as of May 6, 2005, by and between Natural Gas Systems, Inc. and Rubicon Master Fund	Previously Filed
10.8	Executive Employment Agreement, Daryl V. Mazzanti ("Mazzanti"), dated June 23, 2005	Previously Filed
10.9	Mazzanti Stock Option Agreement, dated June 23 2005	Previously Filed
10.10	Mazzanti Stock Grant Agreement dated June 23, 2005	Previously Filed
10.11	Mazzanti Revocable Warrant Agreement, dated June 23, 2005	Previously Filed
10.12	Securities Purchase Agreement dated as of January 13, 2006 by and between Natural Gas Systems, Inc. and Rubicon Master Fund	Previously Filed
10.13	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
10.14	Subordinated Promissory Note, dated March 3, 2006, between Natural Gas Systems, Inc. and Laird Q. Cagan.	Previously Filed
10.15	Master Services Agreement, dated September 29, 2005, by and between the NGS Technologies, Inc. and MTEM, LTD	Previously Filed
10.16	Agreement with Chadbourn Securities, Inc., dated February 13, 2006.	Previously Filed
10.17	Agreement with Cagan McAfee Capital Partners, LLC, dated February 13, 2006.	Previously Filed
10.18	Purchase and Sale Agreement, by and between NGS Sub Corp. and Denbury Onshore, LLC, dated May 9, 2006.	Previously Filed
10.19	Purchase and Sale Agreement I, by and between NGS Sub Corp. and Denbury Onshore, LLC, dated May 8, 2006.	Previously Filed
10.20	Purchase and Sale Agreement II, by and between NGS Sub Corp. and Denbury Onshore, LLC, dated May 8, 2006.	Previously Filed
10.21	Unit Operating Agreement, by and between NGS Sub Corp. and Denbury Onshore, LLC, dated May 8, 2006.	Previously Filed
10.22	Conveyance, Assignment and Bill of Sale Agreement, by and between NGS Sub Corp. and Denbury Onshore, LLC, dated May 8, 2006.	Previously Filed
10.23	Form of Indemnification Agreement for Officers and Directors, as adopted on September 20, 2006.	Previously Filed
14.1	Code of Ethics for Natural Gas Systems, Inc.	Previously Filed
21.1	List of all subsidiaries of the Company.	Included
31.1	Certification of Chief Executive Officer pursuant to Section 302 of Sarbanes-Oxley Act of 2002.	Included
31.2	Certification of Chief Financial Officer pursuant to Section 302 of Sarbanes-Oxley Act of 2002.	Included
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.	Included
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.	Included
99.1	Audit Committee Charter of the Board of Directors of Natural Gas Systems, Inc.	Previously Filed
99.2	Compensation Committee Charter of the Board of Directors of Natural Gas Systems, Inc.	Previously Filed
99.3	Nominating Committee Charter of the Board of Directors of Natural Gas Systems, Inc.	Previously Filed

Item 14. Principal Accountants 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 2006 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. 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
Chief Financial Officer
(Principal Financial and
Accounting Officer)

Date: September 27, 2006

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 27, 2006	/s/ E. J. DIPAOLO E. J. DiPaolo	Director
September 27, 2006	/s/ GENE STOEVER Gene Stoever	Director
September 27, 2006	/s/ WILLIAM DOZIER William Dozier	Director
September 27, 2006	/s/ LAIRD Q. CAGAN Laird Q. Cagan	Chairman of the Board

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 and Natural Gas Systems
Four Star Development Corporation	Louisiana	Four Star Development Corporation and Natural Gas Systems
NGS Technology	Delaware	NGS Technology

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 Registrant as of, and for, the periods presented in this report;

4. The Registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the Registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Evaluated the effectiveness of the Registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

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

5. The Registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Registrant's auditors and the audit committee of Registrant'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 Registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant's internal control over financial reporting.

Date: September 27, 2006

/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 Registrant as of, and for, the periods presented in this report;

4. The Registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the Registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Evaluated the effectiveness of the Registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

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

5. The Registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Registrant's auditors and the audit committee of Registrant'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 Registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant's internal control over financial reporting.

Date: September 27, 2006

/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, 2005 (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 27th day of September, 2006.

/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, 2005 (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 27th day of September, 2006.

/s/ STERLING H. McDONALD

Sterling H. McDonald
Chief Financial Officer