ReoStar Energy CORP
Form 10-K/A
April 09, 2010

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

FORM 10-K /A

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

For the fiscal year ended March 31, 2009

Commission file number 000-26139

REOSTAR ENERGY CORPORATION
(Name of small business issuer in its charter)

Nevada (State or other jurisdiction of incorporation or organization)	20-8428738 (IRS Employer Identification Number)
3880 Hulen St., Ste 500, Fort Worth, TX (Address of principal executive offices)	76107 (Zip Code)

Registrant's telephone number: 817-989-7367

Securities registered under Section 12(b) of the Exchange Act:
None

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

Common Stock, $.001 par value
(Title of class)

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Exchange Act. o

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 229.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o

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

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

Large accelerated filer o	Accelerated filer o
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company x

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

The aggregate market value of the common stock held by non-affiliates computed by reference to the closing sales price of such common equity as of the last business day of the registrant's most recently completed first fiscal quarter was $2,515,191.

The number of shares outstanding of the registrant's common stock as of July 10, 2009 was 80,353,912 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the registrant's 2009 annual meeting of shareholders to be filed with the SEC within 120 days after the end of the fiscal year ended March 31, 2009 are incorporated by reference in Part III of this Form 10-K.

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

EXPLANATORY NOTE: ReoStar Energy Corporation is amending its Annual Report on Form 10-K for the fiscal year ended March 31, 2009 filed on July 14, 2009 to correct an error in the calculation of proved undeveloped reserves related to the surfactant polymer flood project in its Corsicana field. Item 2. Properties in this Annual Report and Footnote 17 to the financial statements have been amended to correct the error in the proved undeveloped reserve figure. The remaining items in this Form 10-K/A consist of all other items contained in our Annual Report on Form 10-K for the fiscal year ended March 31, 2009 originally filed with the SEC on July 14, 2009.

REOSTAR ENERGY CORPORATION
FORM 10-K ANNUAL REPORT
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Disclosures Regarding Forward-Looking Statements

Certain information included in this report, other materials filed or to be filed with the Securities and Exchange Commission (the "SEC"), as well as information included in oral statements or other written statements made or to be made by us contain or incorporate by reference certain statements (other than statements of historical fact) that constitute forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. When used herein, the words "budget," "budgeted," "assumes," "should," "goal," "anticipates," "expects," "believes," "seeks," "plans," "estimates," "intends," "projects" or "targets" and similar expressions that convey the uncertainty of future events or outcomes are intended to identify forward-looking statements. Where any forward-looking statement includes a statement of the assumptions or bases underlying such forward-looking statement, we caution that while we believe these assumptions or bases to be reasonable and to be made in good faith, assumed facts or bases almost always vary from actual results and the difference between assumed facts or bases and the actual results could be material, depending on the circumstances. It is important to note that our actual results could differ materially from those projected by such forward-looking statements. Although we believe that the expectations reflected in such forward-looking statements are reasonable and such forward-looking statements are based upon the best data available at the date this report is filed with the SEC, we cannot assure you that such expectations will prove correct. Factors that could cause our results to differ materially from the results discussed in such forward-looking statements include, but are not limited to, the following: the factors described in Item 1A of this report under the heading "Risk Factors," production variance from expectations, volatility of oil and gas prices, hedging results, the need to develop and replace reserves, the substantial capital expenditures required to fund operations, exploration risks, environmental risks, uncertainties about estimates of reserves, competition, litigation, government regulation, political risks, our ability to implement our business strategy, costs and results of drilling new projects, mechanical and other inherent risks associated with oil and gas production, weather, availability of drilling equipment and changes in interest rates. All such forward-looking statements in this document are expressly qualified in their entirety by the cautionary statements in this paragraph, we do not undertake, and specifically disclaim any obligation, to update or revise such statements to reflect new circumstances or unanticipated events as they occur, and we urge readers to review and consider disclosures we make in this and other reports that discuss factors germane to our business, including our reports on Forms 10-K, 10-Q, and 8-K subsequently filed from time to time with the SEC.

PART I

ITEM 1. BUSINESS

General

Effective February 1, 2007 three entities contributed certain assets to Goldrange Resources, Inc. ("Goldrange") in exchange for stock. The contributing entities were under common control prior to the transaction, and immediately after the transactions, the former shareholders of the contributing entities owned 80.4% of the issued and outstanding stock of Goldrange. The contribution was accounted for as a reverse merger, therefore, all assets are carried on the balance sheet at historical cost. The predecessor entities kept accounting records based on a calendar year end. However, Goldrange's year end was March 31. Therefore, for 2006 and prior years, all data presented reflects data using a calendar year end.

We are engaged in the exploration, development and acquisition of oil and gas properties, primarily located in the state of Texas. We seek to increase oil and gas reserves and production through internally generated drilling projects on currently owned assets, coupled with complementary acquisitions.

At year-end 2009, we owned approximately 16,000 acres of leasehold, which includes 12,000 acres of exploratory and developmental prospects as well as 4,000 acres of enhanced oil recovery prospects. We have built a multi-year inventory of drilling projects and drilling locations and currently have enough acreage to sustain several years of drilling. We had also entered into a non-binding letter of intent to acquire 13,000 acres of leasehold in south Texas in the Eagle Ford Shale/Edwards trend area.

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ReoStar was incorporated in Nevada on November 29, 2004 under the name Goldrange Resources, Inc. In February of 2007 we changed our name to ReoStar Energy Corporation.

Our corporate offices are located at 3880 Hulen Street, Suite 500, Fort Worth, Texas 76107. Our telephone number is (817) 989-7367.

Business Strategy

Our objective is to build shareholder value by establishing and consistently growing our production and reserves with a strong emphasis on cost control and risk mitigation. Our strategy is (1) to control operations of all our leases through our affiliated operating companies, (2) to acquire and develop leasehold in key regional resource development plays while utilizing existing infrastructure and engaging in long-term drilling and development programs, and (3) to acquire leasehold in mature fields and implement enhanced oil recovery programs.

Significant Accomplishments in Fiscal Year 2009

Leasehold Acquisition and Development:

Barnett Shale. Our main area of interest in the Barnett Shale play is located in the "oil window" of the Barnett in southwest Cooke County, Texas.

We completed, and began production in the seven wells that were in process as of March 31, 2008. We also drilled, completed, and began production in six wells. Two other wells were drilled that we anticipate will be completed in the second quarter of fiscal year 2010.

Corsicana Enhanced Oil Recovery (EOR) Project. We began injecting surfactant polymer in phase I of the project in mid-June 2007 and continued injection throughout the current fiscal year. We initiated phase II of the project by drilling 12 wells in June 2008 in an area immediately south of our injection facility adjacent to the phase I wells.

Corsicana deeper zone exploration. We drilled four deeper exploratory wells in the Corsicana acreage. The first two, a Glen Rose well and a Pecan Gap well were dry holes. In December 2008, we successfully completed two Pecan Gap wells.

Eagle Ford Shale. In March 2009, we entered into a non-binding letter of intent to acquire a 100% working interest (75% net revenue interest) in 13,000 acres of leasehold in South Texas. The acreage is in the Edwards trend and has both Edwards and Eagle Ford Shale prospects.

Concentrate in Core Operating Areas. We currently focus in one region: the Southern Mid-continent region of the United States (which includes the Barnett Shale of North Central Texas, and our Corsicana EOR prospect in East Central Texas, and the Eagle Ford/Edwards trend in South Texas). Concentrating our drilling and producing activities in these core areas allows us to develop the regional expertise needed to interpret specific geological and operating trends and develop economies of scale. Operating developmental projects (such as our Barnett Shale prospects) and Enhanced Oil Recovery prospects in the same core area allows us to achieve reserve growth, balance our portfolio between oil and natural gas, and minimize some of the operational risks inherent in our industry, while leveraging the benefits of the existing infrastructure.

Manage Our Risk Exposure. We continue to sell a portion of the working interests in the development wells we drill, which allows us to spread the risk by drilling more wells for the same capital expenditure budget.

Corporate Financing. We secured a $25 million senior secured credit facility with Union Bank of California in October 2008. The credit (borrowing base) available under the credit facility is determined based upon our reserves. The credit facility is secured by all of our assets. The interest rate varies depending upon the

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reference rate (either LIBOR or Prime) and the amount of the borrowing base utilized. At March 31, 2009, the borrowing base was $14 million. We have drawn $9.8 million and the interest rate was 2.82%.

Plans for fiscal year 2010

Barnett Shale

In December 2008, we suspended our Barnett Shale development due to depressed natural gas prices. We do not expect to renew the development program during this fiscal year. However, we have two drilling commitments and expect to drill one cluster of six wells in order to fulfill those commitments. The drilling budget for the Barnett acreage is $6.0 million for fiscal year 2010. The drilling budget will allow us to fulfill our drilling commitments by drilling one cluster and complete the two wells that were in process at year-end. The capital expenditure budget assumes we will retain 100% working interests in the wells. However, our normal practice is to sell a portion of the working interests in our wells under a turn-key contract. We expect to fund the drilling with the proceeds of a debt facility and proceeds from the sale of up to 40% working interest in each well on a turnkey basis.

Corsicana

We have applied for an area wide injection permit, which when granted will allow us to streamline the regulatory permitting process. Upon approval, we expect to begin injection in Phase II of the polymer flood. We expect to begin drilling Phase III of the surfactant-polymer project in the fourth quarter of the fiscal year.

We will drill three more Pecan Gap wells in July 2009. If the wells are successful, we expect to initiate a Pecan Gap drilling program and will drill up to 5 wells per month for the balance of the fiscal year. The Pecan Gap lies at about 1,800 feet and are economical to drill. We will sell up to 50% working interest in these wells on a turn-key contract basis.

During the fiscal year ended March 31, 2009, we acquired and began to refurbish a shallow well oil drilling rig capable of drilling wells up to 3,500 feet deep. The refurbishment was completed during the first quarter of the 2010 fiscal year and the rig will be used on the Pecan Gap drilling program and to drill the surfactant polymer project wells.

The planned surfactant polymer wells are shallow (800 ft.), and cost approximately $60,000 each to drill and complete. The Pecan Gap wells cost approximately $100,000 each to drill and complete. Total capital expenditure budget for fiscal 2010 for the Corsicana project is $3.5 million. The budget will be funded primarily with proceeds from the sale of up to 50% working interest in the Pecan Gap wells, the credit facility, and cash flow.

South Texas

During the first quarter of the fiscal year, we signed a contract to purchase 13,000 acres in South Texas. The purchase price was $5.5 million of cash and 12 million shares of ReoStar stock. The technical team, with significant experience in South Texas, will remain in place, and will be the operator of record. They will provide the technical expertise required to be successful in the Edwards and Eagle Ford Shale plays. The contract requires the Company to arrange $15 million in financing prior to August 1, 2009. The Company is working with an investment bank in Europe and several sources in the United States. The financing may take the form of equity, convertible debt, or a combination of equity and debt. The proceeds of the financing will be used to fund the cash portion of the purchase price and to fund stage I capital expenditures. The first stage will be comprised of a science well and re-entries of three existing vertical well bores.

Given the current state of equity markets, there can be assurance that we will be successful in raising the capital necessary to close the South Texas acquisition.

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Production, Revenues and Price History

The following table sets forth information regarding oil and gas production, and revenues for ReoStar Energy. Data shown for the 2006 and 2005 calendar years are combined results of the predecessor entities.

	March 31,		March 31,		December 31,		
Years Ending	2009		2008		2006		2005
Production							
Oil (Bbl)	45,105		33,602		34,607		8,965
Gas (Mcf)	479,180		351,538		199,282		94,358
Revenues							
Crude Oil	$ 4,034,376	$	2,704,468	$	1,772,649	$	555,097
Gas	2,523,693		2,197,604		1,101,642		554,102
Total	6,558,069		4,902,072		2,874,291		1,109,199
Average Sale Price per Bbl	89.44	$	80.49	$	51.22	$	61.92
Average Sale Price per MCF	5.27	$	6.25	$	5.53	$	5.87
Lease Operating Costs (per BOE)	20.79	$	23.05	$	16.68	$	22.59
Severance Taxes (per BOE)	3.00	$	3.13	$	2.41	$	2.67
Average Sale Price (per BOE)	52.48	$	53.17	$	42.38	$	44.92
Average Sale Price (per MCFE)	8.75	$	8.86	$	7.06	$	7.49

(a) Natural Gas was converted to BOE at the rate of 1 barrel equals 6 MCF.

Competition

We encounter substantial competition in developing and acquiring oil and gas properties, securing and retaining personnel, conducting drilling and field operations and marketing production. Competitors in exploration, development, acquisitions and production include the major oil companies as well as numerous independent oil companies, individual proprietors and others. Although our sizable acreage position and core-area concentration provide some competitive advantages, many competitors have financial and other resources substantially exceeding ours. Therefore, competitors may be able to pay more for desirable leases and to evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources allow. Our ability to replace and expand our reserve base depends on our ability to attract and retain quality personnel and our ability to identify and acquire suitable producing properties and prospects for future drilling.

Employees

As of April 1, 2009, ReoStar Energy Corporation had 4 full-time and no part-time employees.

All of ReoStar's full-time employees are eligible to receive equity awards approved by the Compensation Committee of the Board of Directors. No employees are covered by a labor union or other collective bargaining arrangement. We believe that the relationship with our employees is excellent. We regularly utilize independent consultants and contractors to perform various professional services, particularly in the areas of drilling, completion, field and on-site production operation services, mainly through our affiliated operators, Texas M.O.R., Inc. and Rife Energy Operating, Inc.

Available Information

We maintain an internet website under the name "www.reostarenergy.com." Information contained on or connected to our website is not incorporated by reference into this Form 10-K and should not be considered part of this report or any other filing that we make with the SEC. We make available, free of charge, on our website, the

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annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports, as soon as reasonably practicable after providing such reports to the SEC. Also, our Code of Ethics is available on our website and in print to any stockholder who provides a written request to Investor Relations at 3880 Hulen Street, Suite 500, Fort Worth, Texas 76107.

We file annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, proxy statements and other documents with the SEC under the Securities Exchange Act of 1934. The public may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers, including REOSTAR, that file electronically with the SEC. The public can obtain any document we file with the SEC at "www.sec.gov."

Marketing and Customers

We market nearly all of our oil and gas production from the properties we operate for both our interest and that of the other working interest owners and royalty owners. All of our gas produced from the Barnett Shale is sold pursuant to a gas contract with Copano Field Services/North Texas LLC. The contract expires May 31, 2017 and provides for two stages of gathering fees. For all wells in production through December 31, 2010, a gathering fee of $0.55 per MMBTU is assessed against our revenue. Thereafter, for all wells in production as of December 31, 2010, no gathering fee will be assessed. Currently, none of our gas is sold under long-term fixed price contracts. Our Barnett oil is currently sold to Cimmarron Gathering, LP under a month to month contract until such time as either party cancels by providing thirty (30) days advance written notice to the other party of intent to cancel. The contract pays Platts plus minus $1.00 based on Plains - North Texas Sweet posted price.

Oil and gas purchasers are selected on the basis of price, credit quality and service. For a summary of purchasers of our oil and gas production that accounted for 10% or more of consolidated revenue, see Note 13 to our financial statements. Because alternative purchasers of oil and gas are usually readily available, we believe that the loss of any of these purchasers would not have a material adverse effect on us.

Currently, we have no hedges in place. We expect to implement a comprehensive hedging program during this fiscal year with unaffiliated third parties for portions of our production to achieve more predictable cash flows and to reduce our exposure to down-side price risk.

Proximity to local markets, availability of competitive fuels and overall supply and demand are factors affecting the prices for which our production can be sold. Market volatility due to international political developments, overall energy supply and demand, fluctuating weather conditions, economic growth rates and other factors in the United States and worldwide has had, and will continue to have, a significant effect on energy prices.

For additional information, see "Risk Factors".

Governmental Regulation

Federal, state and local laws and regulations substantially affect our operations. In particular, oil and gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which we own or operate producing crude oil and natural gas properties have statutory provisions regulating the exploration for and production of crude oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements in order to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling

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and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individuals wells.

In August 2005, Congress enacted the Energy Policy Act of 2005 ("EPAct 2005"). Among other matters, the EPAct 2005 amends the Natural Gas Act ("NGA"), to make it unlawful for "any entity", including otherwise non-jurisdictional producers such as ReoStar, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the Federal Energy Regulatory Commission ("FERC"), in contravention of rules prescribed by the FERC. On January 20, 2006, the FERC issued rules implementing this provision. The rules make it unlawful in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 also gives the FERC authority to impose civil penalties for violations of the NGA up to $1,000,000 per day per violation. The new anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sale or gathering, but does apply to activities or otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction. It therefore reflects a significant expansion of FERC's enforcement authority. ReoStar does not anticipate it will be affected any differently than other producers of natural gas.

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Congress, the states, the FERC, and the courts regularly consider additional proposals and proceedings that affect the oil and gas industry. We cannot predict when or whether any such proposals may become effective.

Environmental Matters

Our operations are subject to stringent federal, state and local laws governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous governmental departments such as the Environmental Protection Agency ("EPA") issue regulations to implement and enforce such laws, which are often difficult and costly to comply with and which carry substantial civil and criminal penalties for failure to comply. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, frontier and other protected areas, require some form of remedial action to prevent pollution from former operations such as plugging abandoned wells, and impose substantial liabilities for pollution resulting from operations. In addition, these laws, rules and regulations may restrict the rate of production. The regulatory burden on the oil and gas industry increases the cost of doing business, affecting growth and profitability. Changes in environmental laws and regulations occur frequently, and changes that result in more stringent and costly waste handling, disposal or clean-up requirements could adversely affect our operations and financial position, as well as the industry in general. We believe we are in substantial compliance with current applicable environmental laws and regulations. Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters during fiscal year ended 2008, nor do we anticipate that such expenditures will be material in fiscal year ended 2009.

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, on certain

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classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include owners or operators of the disposal site or sites where the release occurred and companies that disposed of or arranged for the disposal of the hazardous substances at the site where the release occurred. Under CERCLA, such persons may be subject to joint and several liabilities for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. Furthermore, although petroleum, including crude oil and natural gas, is not a "hazardous substance" under CERCLA, at least two courts have ruled that certain wastes associated with the production of crude oil may be classified as "hazardous substances" under CERCLA and that such wastes may therefore give rise to liability under CERCLA. Beyond CERCLA, state laws regulate the disposal of oil and gas wastes, and periodically new state legislative initiatives are proposed that could have a significant impact on us. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damages allegedly caused by the release of hazardous substances or other pollutants into the environment pursuant to environmental statutes, common law or both.

The Federal Water Pollution Control Act ("FWPCA") imposes restrictions and strict controls regarding the discharge of produced waters and other oil and gas wastes into waters of the United States. Permits must be obtained to discharge pollutants into state and federal waters. The FWPCA and analogous state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of oil and other hazardous substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages. State water discharge regulations and Federal National Pollutant Discharge Elimination System permits applicable to the oil and gas industry generally prohibit the discharge of produced water, sand and some other substances into coastal waters. The cost to comply with zero discharges mandated under federal and state law has not had a material adverse impact on our financial condition and results of operations.

Some oil and gas exploration and production facilities are required to obtain permits for their storm water discharges. Costs may be incurred in connection with treatment of wastewater or developing and implementing storm water pollution prevention plans. The Resource Conservation and Recovery Act ("RCRA") as amended, generally does not regulate most wastes generated by the exploration and production of oil and gas. RCRA specifically excludes from the definition of hazardous waste "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy." However, these wastes may be regulated by the EPA or state agencies as non-hazardous solid waste. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils, can be regulated as hazardous wastes. Although the costs of managing wastes classified as hazardous waste may be significant, we do not expect to experience more burdensome costs than similarly situated companies.

The Oil Pollution Act ("OPA") requires owners and operators of facilities that could be the source of an oil spill into "waters of the United States" (a term defined to include rivers, creeks, wetlands and coastal waters) to adopt and implement plans and procedures to prevent any spill of oil into any waters of the United States. OPA also requires affected facility owners and operators to demonstrate that they have sufficient financial resources to pay for the costs of cleaning up an oil spill and compensating any parties damaged by an oil spill. Substantial civil and criminal fines and penalties can be imposed for violations of OPA and other environmental statutes.

Stricter standards in environmental legislation may be imposed on the oil and gas industry in the future. For instance, legislation has been proposed in Congress from time-to-time that would alter the RCRA exemption by reclassifying certain oil and gas exploration and production wastes as "hazardous wastes" and make the waste subject to more stringent handling, disposal and clean-up restrictions. If such legislation were enacted, it could have a significant impact on our operating costs, as well as the industry in general. Compliance with environmental requirements generally could have a material adverse effect on our capital expenditures, earnings or competitive position. Although we have not experienced any material adverse effect from compliance with environmental requirements, no assurance may be given that this will continue.

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ITEM 1A. RISK FACTORS

An investment in our common stock is speculative and involves a high degree of risk and uncertainty. You should carefully consider the risks described below, together with the other information contained in our reports filed with the SEC, including the consolidated financial statements and notes thereto of our company, before deciding to invest in our common stock. The risks described below are not the only ones facing our company. Additional risks not presently known to us or that we presently consider immaterial may also adversely affect our company. If any of the following risks occur, our business, financial condition and results of operations and the value of our common stock could be materially and adversely affected.

Volatility of oil and natural gas prices significantly affects our cash flow and capital resources and could hamper our ability to produce oil and gas economically.

Oil and natural gas prices are volatile, and a decline in prices would adversely affect our profitability and financial condition. The oil and natural gas industry is typically cyclical, and prices for oil and natural gas have been highly volatile. Historically, the industry has experienced severe downturns characterized by oversupply and/or weak demand. In recent years, higher oil and natural gas prices have contributed to increased earnings industry wide. However, long-term supply and demand for oil and natural gas is uncertain and subject to a myriad of factors such as:

- the domestic and foreign supply of oil and gas;
- the price and availability of alternative fuels;
- weather conditions;
- the level of consumer demand;
- the price of foreign imports;
- world-wide economic conditions;
- political conditions in oil and gas producing regions; and
- domestic and foreign governmental regulations.

Decreases in oil and natural gas prices from current levels could adversely affect our revenues, net income, cash flow and economically recoverable proved reserves. Significant price decreases could have a material adverse effect on our operations and limit our ability to fund capital expenditures. Without the ability to fund capital expenditures, we would be unable to replace reserves and production.

High operating costs are inherent in enhanced oil recovery projects and could impair our ability to produce oil and gas economically.

The Company has initiated a surfactant polymer flood, which is classified as an enhanced oil recovery project. The cost of the surfactants and polymers, the cost of preparing the mixture for injection, the cost of injection, the cost of monitoring the quality of the injected solution, and the cost of monitoring the results all contribute to operating expenses which are significantly higher than operating expenses incurred using primary and secondary recovery techniques. Additionally, the response time, response rate, and overall recovery rate of a surfactant polymer flood are uncertain, which could materially impact the operating cost per unit produced.

Due to the higher operating costs (which for the fiscal year ended March 31, 2008 averaged more than $30.00 per BOE), a significant decline in commodity prices could magnify the negative impact on net income, cash flow and proved reserves.

Hedging transactions may limit our potential gains and involve other risks.

To manage our exposure to price risk, we may, from time to time, enter into hedging arrangements, utilizing commodity derivatives with respect to a significant portion of our future production. The goal of hedging is to lock in prices so as to limit volatility and increase the predictability of cash flow. These transactions may limit

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potential gains if oil and natural gas prices rise above the price established by the hedge. In addition, hedging transactions may cause risk of financial loss in certain circumstances.

Information concerning our reserves and future net reserve estimates is uncertain.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and their values, including many factors beyond our control. Estimates of proved reserves are by their nature uncertain. Although we believe these estimates are reasonable, actual production, revenues and costs to develop will likely vary from estimates, and these variances could be material.

The accuracy of any reserve estimate is a function of the quality of available data; engineering and geological interpretation and judgment; assumptions used regarding quantities of oil and natural gas in place; recovery rates; and future commodity pricing.

Actual prices, production, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from those assumed in our estimates, and such variances may be material. Any variance in the assumptions could materially affect the estimated quantity and value of the reserves.

If oil and natural gas prices decrease or exploration efforts are unsuccessful, we may be required to take write-downs of our oil and natural gas properties.

This could occur when oil and natural gas prices are low, if we have downward adjustments to our estimated proved reserves, increases in our estimates of operating or development costs, deterioration in our exploration results, unsatisfactory results in our enhanced oil recovery projects, or mechanical problems with wells where the cost to re-drill or repair does not justify the expenditures required.

Accounting rules require that the carrying value of oil and natural gas properties be periodically reviewed for possible impairment. "Impairment" is recognized when the book value of a proven property is greater than the expected undiscounted future net cash flows from that property and on acreage when conditions indicate the carrying value is not recoverable. We may be required to write down the carrying value of a property based on oil and natural gas prices at the time of the impairment review, as well as a continuing evaluation of drilling results, production data, economics and other factors. While an impairment charge reflects our long-term ability to recover an investment, it does not impact cash or cash flow from operating activities, but it does reduce our reported earnings and negatively impacts our leverage ratios.

Our business is subject to operating hazards and environmental regulations that could result in substantial losses or liabilities.

Oil and natural gas operations are subject to many risks, including well blowouts, craterings, explosions, uncontrollable flows of oil, natural gas or well fluids, fires, formations with abnormal pressures, pipeline ruptures or spills, pollution, releases of toxic natural gas and other environmental hazards and risks. If any of these hazards occur, we could sustain substantial losses as a result of:

- injury or loss of life;
- severe damage to or destruction of property, natural resources, and equipment;
- pollution or other environmental damage;
- clean-up responsibilities;
- regulatory investigations and penalties; or
- suspension of operations.

As we drill to deeper horizons and in more geologically complex areas, we could experience a greater increase in operating and financial risks due to inherent higher reservoir pressures and unknown downhole risk exposures. As we continue to drill deeper, the number of rigs capable of drilling to such depths will be fewer and we may experience greater competition from other operators.

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Our operations are subject to numerous and increasingly strict federal, state and local laws, regulations and enforcement policies relating to the environment. We may incur significant costs and liabilities in complying with existing or future environmental laws, regulations and enforcement policies and may incur costs arising out of property damage or injuries to employees and other persons. These costs may result from our current and former operations and even may be caused by previous owners of property we own or lease. Any past, present or future failure by us to completely comply with environmental laws, regulations and enforcement policies could cause us to incur substantial fines, sanctions or liabilities from cleanup costs or other damages. Incurrence of those costs or damages could reduce or eliminate funds available for exploration, development or acquisitions or cause us to incur losses.

In accordance with our operating agreements, the operator maintains insurance against some, but not all, of these potential risks and losses. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. We do not maintain business interruption insurance.

In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs that is not fully covered by insurance, it could have a material adverse affect on our financial condition and results of operations.

We are subject to financing and interest rate exposure risks.

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, which limit our ability to pursue acquisition opportunities and place us at a competitive disadvantage.

Many of our current and potential competitors have greater resources than ours, and we may not be able to successfully compete in acquiring, exploring and developing new properties.

We face competition in every aspect of our business, including, but not limited to, acquiring reserves and leases, obtaining goods, services and employees needed to operate and manage our business and marketing oil and natural gas. Competitors include multinational oil companies, independent production companies and individual producers and operators. Many of our competitors have greater financial and other resources than we do.

The demand for field services and their ability to meet that demand may limit our ability to drill and produce our oil and natural gas properties.

Due to current industry demands, well service providers and related equipment and personnel are in short supply. This will result in escalating prices, the possibility of poor services coupled with potential damage to down-hole reservoirs and personnel injuries. Such pressures will likely increase the actual cost of services, extend the time to secure such services and add costs for damages due to accidents sustained from the over use of equipment and inexperienced personnel.

The oil and natural gas industry is subject to extensive regulation.

The oil and natural gas industry is subject to various types of regulations in the United States by local, state and federal agencies. Legislation affecting the industry is under constant review for amendment or expansion, frequently increasing our regulatory burden. Numerous departments and agencies, both state and federal, are authorized by statute to issue rules and regulations binding on participants in the oil and natural gas industry. Compliance with such rules and regulations often increases our cost of doing business and, in turn, decreases our profitability.

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Acquisitions are subject to the risks and uncertainties of evaluating reserves and potential liabilities and may be disruptive and difficult to integrate into our business.

We could be subject to significant liabilities related to acquisitions. It generally is not feasible to review in detail every individual property included in an acquisition. Ordinarily, a review is focused on higher valued properties. However, even a detailed review of all properties and records may not reveal existing or potential problems in all of the properties, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. We do not always inspect every well we acquire, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is performed.

In addition, there is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our acquisition strategy is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Our ability to pursue our acquisition strategy may be hindered if we are not able to obtain financing on terms acceptable to regulatory approvals or us.

Acquisitions often pose integration risks and difficulties. In connection with future acquisitions, the process of integrating acquired operations into our existing operations may result in unforeseen operating difficulties and may require significant management attention and financial resources that would otherwise be available for the ongoing development or expansion of existing operations. Future acquisitions could result in our incurring additional debt, contingent liabilities, expenses and diversion of resources, all of which could have a material adverse effect on our financial condition and operating results.

Our success depends on key members of our management and our ability to attract and retain experienced technical and other professional personnel.

Our success is highly dependent on our management personnel. The loss of one or more of these individuals could have a material adverse effect on our business. Furthermore, competition for experienced technical and other professional personnel is intense. If we cannot retain our current personnel or attract additional experienced personnel, our ability to compete could be adversely affected.

Our future success depends on our ability to replace reserves that we produce.

Because the rate of production from oil and natural gas properties generally declines as reserves are depleted, our future success depends upon our ability to economically find or acquire and produce additional oil and natural gas reserves. Except to the extent that we acquire additional properties containing proved reserves, conduct successful exploration and development activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, our proved reserves will decline as reserves are produced. Future oil and natural gas production, therefore, is highly dependent upon our level of success in acquiring or finding additional reserves that are economically recoverable. We cannot assure you that we will be able to find or acquire and develop additional reserves at an acceptable cost.

New technologies may cause our current exploration and drilling methods to become obsolete.

The oil and natural gas industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. One or more of the technologies that we currently use or that we may implement in the future may become obsolete. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. If we are not able to maintain technological advancements consistent with industry standards, our operations and financial condition may be adversely affected.

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Our business depends on oil and natural gas transportation facilities, most of which are owned by others.

The marketability of our oil and natural gas production depends in part on the availability, proximity and capacity of pipeline systems owned by third parties. The unavailability of or lack of available capacity on these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Although we have some contractual control over the transportation of our product, material changes in these business relationships could materially affect our operations. We generally do not purchase firm transportation on third party facilities and therefore, our production transportation can be interrupted by those having firm arrangements.

Federal and state regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport oil and natural gas.

The disruption of third-party facilities due to maintenance and/or weather could negatively impact our ability to market and deliver our products. We have no control over when or if such facilities are restored or what prices will be charged. A total shut-in of production could materially affect us due to a lack of cash flow, and if a substantial portion of the production is hedged at lower than market prices, those financial hedges would have to be paid from borrowings absent sufficient cash flow.

Indebtedness could limit our ability to successfully operate our business.

If we decide to pursue additional acquisitions, our capital expenditures will increase both to complete such acquisitions and to explore and develop any newly acquired properties. Our existing operations will also require ongoing capital expenditures. We may choose to increase debt in order to finance any of these potential capital expenditure requirements. The degree to which we are leveraged could have other important consequences, including the following:

- we may be required to dedicate a substantial portion of our cash flows from operations to the payment of our indebtedness, reducing the funds available for our operations;
- a portion of our borrowings are at variable rates of interest, making us vulnerable to increases in interest rates;
- we may be more highly leveraged than some of our competitors, which could place us at a competitive disadvantage;
- our degree of leverage may make us more vulnerable to a downturn in our business or the general economy;
- the terms of our credit arrangements could contain numerous financial and other restrictive covenants;
- our debt level could limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- we may have difficulties borrowing money in the future.

Any failure to meet our debt obligations could harm our business, financial condition and results of operations.

If our cash flow and capital resources are insufficient to fund our current or future debt obligations, we may be forced to sell assets, seek additional equity or restructure our debt. In addition, any failure to make scheduled payments of interest and principal on our outstanding indebtedness would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness on acceptable terms. Our cash flow and capital resources may be insufficient for payment of interest on and principal of our debt in the future and any such alternative measures may be unsuccessful or may not permit us to meet scheduled debt service obligations, which could cause us to default on our obligations and impair our liquidity.

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The current global financial crisis may adversely affect our business, operating results and financial condition.

The United States economy has recently experienced a financial downturn, with some financial and economic analysts predicting that the world economy may be entering into a prolonged economic downturn characterized by high unemployment, limited availability of credit and capital, increased rates of default and bankruptcy and decreased consumer and business spending. These developments could negatively affect our business, operating results and financial condition in a number of ways. For example, this downturn has had, and may continue to have, an unprecedented negative impact on the global credit and capital markets, resulting in financing terms that are less attractive to borrowers, and in many cases, the unavailability of certain types of debt or capital financing. If this crisis continues or worsens, and if we are required to obtain financing in the near term to meet our working capital or other business needs, we may not be able obtain that financing. Further, even if we are able to obtain the financing we need, it may be on terms that are not favorable to us, with increased financing costs and restrictive covenants.

We exist in a litigious environment.

Any constituent could bring suit or allege a violation of an existing contract. This action could delay when operations can actually commence or could cause a halt to production until the courts resolve such alleged violations. Not only could we incur significant legal and support expenses in defending our rights, planned operations could be delayed which would impact our future operations and financial condition. Such legal disputes could also distract management and other personnel from their primary responsibilities.

Common stockholders will be diluted if additional shares are issued.

We may incur debt that provides for a conversion to equity. Additionally, we may issue stock as consideration for additional property acquisitions. If we issue additional shares of our common stock in the future, it may have a dilutive effect on our current outstanding stockholders.

Dividend limitations.

Our ability to pay dividends may be limited by covenants imposed under future debt arrangements.

Our financial statements are complex.

Due to accounting rules, our financial statements continue to be complex, particularly with reference to hedging, asset retirement obligations, equity awards, and deferred taxes. We expect such complexity to continue and possibly increase.

Our stock price may be volatile and you may not be able to resell shares of our common stock at or above the price you paid.

The price of our common stock fluctuates significantly, which may result in losses for investors. To date our stock has been lightly traded, with the average daily volume being quite low. The low trading volume may prevent you from liquidating your position in our stock quickly. Additionally, the low trading volume may contribute significantly to price volatility. We expect our stock to be subject to fluctuations as a result of a variety of factors, including factors beyond our control. These include:

- changes in oil and natural gas prices;
- variations in quarterly drilling, re-completions, acquisitions and operating results;
- changes in financial estimates by securities analysts;
- changes in market valuations of comparable companies;
- additions or departures of key personnel; or
- future sales of our stock.

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We may fail to meet expectations of our stockholders or of securities analysts at some time in the future, and our stock price could decline as a result. Furthermore, the ability to access capital has been somewhat impaired due to the financial downturn, which could impact the Company's ability to do the same.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not applicable

ITEM 2. PROPERTIES

The information below summarizes certain data for our core operating areas for the year ended March 31, 2009. Segment reporting is not applicable to us as we have a single company-wide management team that administers all properties as a whole rather than by discrete operating segments. We track only basic operational data by area. We do not maintain complete separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis.

We conduct drilling, production and field operations in the Barnett Shale of North Central Texas, and the Corsicana field of East Central Texas.

Barnett Shale

The Barnett Shale is a non-conventional natural gas resource play located in North Texas. It underlies approximately 5,000 square miles and at least 17 counties. Our leases lie in the north western portion of the Barnett Shale, an area known as the "oil window," due to its production of both oil and gas.

We have drilled and own interests in 68 completed wells, all of which are operated by Rife Energy Operating, Inc., a non-publicly traded affiliated company owned by a shareholder who controls more than 25% of our outstanding stock. Our average working interest is 45%, and our average net revenue interest is 34%. We have approximately 5,743 acres under lease, the majority of which is not classified as proven. During the fiscal year ended March 31, 2009, our Barnett Shale production consisted of 479,000 MCF of natural gas and 32,410 barrels of oil, or approximately 112,250 BOE (673,400 MCFE).

Proved developed producing reserves consisted of 2,812 MMCF of natural gas and 94 M barrels of oil, or, 562 MBOE (3,375 MMCFE). Proved developed non-producing reserves consisted of 494 MMCF of natural gas and 46 M barrels of oil, or, 125 MBOE (750 MMCFE). The majority of the proved developed non-producing reserves represented the reserves associated with 2 wells that were drilled, but were not yet completed. Total proved developed reserves at March 31, 2009 were 687 MBOE (4,125 MMCFE). Total proven, undeveloped reserves consisted of 8,505 MMCF natural gas and 655 M barrels of oil, or, 2,070 MBOE (12,430 MMCFE).

At March 31, 2009, we had a Barnett Shale drilling inventory of more than 200 drilling locations and more than 10 re-completions.

Corsicana Field

We own interests in 77 producing well bores and 199 inactive wells. All of our properties in Corsicana are operated by Texas MOR, Inc, a non-publicly traded affiliate. Our average working interest is 95%, and our average net revenue interest is 76%. We commenced flooding on Phase I of our polymer project in June of 2007. Through March 31, 2009, we have injected 291,060 barrels of fluid. During the fiscal year ended March 31, 2009, our oil production in the Corsicana field totaled 10,500 barrels of oil.

The Nacatoch reservoir is fairly shallow with depths of less than 1,000 feet. While this field has been producing for more than one hundred years, several engineering studies have estimated that more than 80% of the original reserves still remain in place or approximately 100 MMBO.

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In addition to the Polymer flood, we are evaluating optional EOR techniques including the use of steam and fire floods.

There are many alternative reservoirs between 1000 and 7000 feet, which are being evaluated for optimal exploitation. The company feels that there are tremendous opportunities in the multiple zones within this range and it plans on attempting to produce from each one.

During the fiscal year ended March 31, 2009, the Company drilled four Pecan Gap test wells. Two of the wells were successfully completed in December. The Company plans to drill three more Pecan Gap wells in July 2009. If these wells are successful, the Company expects to begin an extensive drilling program, and may drill up to 200 more Pecan Gap wells. The Pecan Gap formation lies at about 1,800 feet, and the wells cost approximately $100,000 to drill and complete. The Company has secured co-financing for these wells from an industry partner who has purchased a 50% working interest in the first three wells and expects to sell up to 50% of any additional Pecan Gap wells we drill.

As of March 31, 2009, total proved developed reserves were 187 MBOE and proved undeveloped reserves totaled 33 MBOE.

East Texas Properties

We own interest in 4 leases in eastern Texas and western Louisiana. Our average working interest is 50% and our average net revenue interest is 40%. For the year ended March 31, 2009, our East Texas production consisted of 1,960 barrels of oil.

As of March 31, 2008, total proved developed reserves were 13 MBOE. There were no proved undeveloped reserves.

Fayetteville Shale

We own 6,450 net acres in the Fayetteville Shale located in Arkansas. No wells have been drilled on this acreage and no reserve values have been assigned to the leasehold interests. The leasehold interests are not contiguous and we offered the acreage for sale during fiscal year 2009. During the fall and winter of 2009, natural gas prices tumbled, and we received no offers on the property. The leases begin to expire in late 2010. Because the Company does not plan to drill on the acreage and due to the lack of a market for the leasehold, the entire acreage was written off for financial accounting purposes. The Company will continue to actively seek a buyer for the acreage.

Proven Reserves

Proven oil and gas reserves are defined as the estimated quantities of crude oil, condensate, natural gas liquids and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable 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.

See financial statement footnote number 16, "Supplemental Info on Oil and Gas Exploration, Development, and Production Activities" for the disclosures required by SFAS 69 and more detailed information regarding our proven reserves.

At year-end 2009, the independent petroleum-consulting firm of Forrest Garb and Associates, Inc. reviewed our reserves. These engineers were selected for their geographic expertise and their history in engineering enhanced oil recovery prospects similar to our Corsicana properties. At March 31, 2009, these consultants reviewed 100% of our proved reserves.

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All estimates of oil and gas reserves are subject to uncertainty. The following table sets forth the estimated proven reserves in barrel of oil equivalents and the benchmark prices used in projecting them (in thousands except prices):

Estimated Proved Reserves	***Barnett Shale***	***Corsicana Field***	***E. Texas Field***	***Total***
Proved Developed (MBOE)	688	187	13	888
Proved Undeveloped (MBOE)	2,072	33	-	2,105
Total Proven Reserves at March 31, 2009	2,760	220	13	2,993
Benchmark Pricing				
Natural Gas per mmbtu	$3.58			
Crude Oil per barrel	$49.65			

There are numerous uncertainties inherent in estimating reserves and related information and different reservoir engineers often arrive at different estimates for the same properties. No estimates of our reserves have been filed with or included in reports to another federal authority or agency.

Wells are classified as crude oil or natural gas according to their predominant production stream.

The day-to-day operations of oil and gas properties are the responsibility of the operator designated under pooling or operating agreements. The operator supervises production, maintains production records, employs or contracts for field personnel and performs other functions. An operator receives reimbursement for direct expenses incurred in the performance of its duties as well as monthly per-well producing and drilling overhead reimbursement at rates customarily charged by unaffiliated third parties. The charges customarily vary with the depth and location of the well being operated. Our operators are affiliated with ReoStar and are owned by shareholders who own more than 15% of our issued and outstanding common stock.

Undeveloped Acreage Expirations

A significant amount of our Barnett Shale acreage is not yet held by production. However, due to our planned drilling schedules and lease renewal provisions, we do not anticipate significant leasehold expirations during the next two years.

Our Corsicana properties and east Texas properties are held by production.

Title to Properties

We believe that we have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. As is customary in the industry, in the case of undeveloped properties, often minimal investigation of record title is made at the time of lease acquisition. Investigations are made prior to the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use or affect the value of the properties. Burdens on properties may include:

- customary royalty interests;
- liens incident to operating agreements and for current taxes;
- obligations or duties under applicable laws;
- development obligations under oil and gas leases; or
- burdens such as net profit interests.

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Our headquarters are located at 3880 Hulen St, Suite 500, Fort Worth, Texas. We lease approximately one-half of the 12,000 square feet of office space under a sublease with the remaining half occupied by our affiliated operating entities, each of which contribute to the costs of leasing and maintenance of the leasehold, pro-rata to their respective usage. The term of the sub-lease is three years, and we pay rent at a rate of $1.10 per square foot, per month. Our administrative and office facilities are suitable for their respective uses.

ITEM 3. LEGAL PROCEEDINGS

On September 15, 2008, a royalty owner in the Corsicana polymer pilot, representing approximately one-third of the mineral ownership, filed an amendment to a suit originally filed in 2007. The amendment was filed to include the Company as a defendant. The suit, filed in the 13th Judicial District Court in Navarro County, Texas, alleges the lease has expired because no oil was produced from January 2005 through September 2005. The plaintiff has asked the court to declare the lease to be void; demands payment for any oil produced and sold subsequent to the time the lease expired; demands that all equipment and salvage located on the lease be given by court order to the plaintiff; and asks that any plugging liability be adjudged to be the responsibility of the Company.

The other royalty owners representing the remaining two-thirds mineral ownership have ratified the lease.

In October 2008, the court issued an order requiring the Company and plaintiff to attend mediation to settle the matter. The Company and plaintiff attended mediation in Corsicana, Texas, but were unable to resolve the matter during mediation. In March, the plaintiff filed a motion for summary judgment. The Court has not yet ruled on the motion.

If the plaintiff should prevail in the lawsuit, the amount of the loss contingency cannot be reasonable estimated; therefore no expense for this contingency has been recorded on the accompanying financial statements.

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

There were no matters submitted to a vote of our security holders during the fourth quarter of 2009.

PART II

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

Market Information

Our common stock is currently quoted for trading on Over-the-Counter Bulletin Board (OTCBB) maintained by the Financial Industry Regulatory Authority (FINRA) under the symbol "REOS". There was no active market or any trading volume with respect to the shares of our common stock in the periods prior to the quarter ended December 31, 2006.

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The following table sets forth the high and low closing sale price of our common stock, as reported by the National Association of Securities Dealers Composite for each quarter during the past two fiscal years.

Fiscal 2009	High	Low
30-Jun-08	$0.95	$0.20
30-Sep-08	$0.74	$0.20
31-Dec-08	$0.50	$0.10
31-Mar-09	$0.30	$0.05

Fiscal 2008	High	Low
30-Jun-07	$1.28	$1.05
30-Sep-07	$1.30	$1.02
31-Dec-07	$1.42	$0.80
31-Mar-08	$1.04	$0.62

Holders of Record

On March 31, 2009, there were approximately 90 holders of record of our common stock.

Dividends

We have not paid any cash dividends on our Common Stock, and do not anticipate paying cash dividends on our Common Stock in the next year. We anticipate that any income generated in the foreseeable future will be retained for the development and expansion of our business. Future dividend policy is subject to the discretion of the Board of Directors and will depend upon a number of factors, including future earnings, debt service, debt covenants, capital requirements, business conditions, the financial condition of the Company and other factors that the Board of Directors may deem relevant.

ITEM 6. SELECTED FINANCIAL DATA

Not applicable.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. This section should be read in conjunction with the financial statements and the accompanying notes included elsewhere in this Form 10-K.

Statements in our discussion may be forward-looking. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause future production, revenues and expenses to differ materially from our expectations. See "Disclosures Regarding Forward-Looking Statements" at the beginning of this Annual Report and "Risk Factors" in Item 1A for additional discussion of some of these factors and risks.

Overview of Our Business

We are an independent natural gas and oil company engaged in the acquisition, development, and exploration of oil and gas properties, primarily in Texas. Our objective is to build a balanced portfolio consisting of oil and gas producing properties and reserves in both resource (developmental) and enhanced

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oil recovery (redevelopment) plays. We will expand reserves through internally generated drilling projects coupled with complementary acquisitions.

Our revenues, profitability and future growth depend substantially on prevailing prices for oil and gas and on our ability to find, develop and acquire oil and gas reserves that are economically recoverable. Our profitability depends upon our ability to control operations of our oil and gas assets.

We have a single company-wide management team that administers all properties as a whole rather than by independent operating segments. We track only basic operational data by area and we do not maintain complete separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis.

Successful Efforts Method of Accounting

We account for our exploration and development activities utilizing the successful efforts method of accounting. Under this method, costs of productive exploratory wells, development dry holes and productive wells and undeveloped leases are capitalized. Oil and natural gas lease acquisition costs are also capitalized. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for oil and natural gas leases, are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities. The sale of a partial interest in a proved property is accounted for as a cost recovery and no gain or loss is recognized as long as this treatment does not significantly affect the unit-of-production amortization rate. A gain or loss is recognized for all other sales of producing properties.

The application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as developmental or exploratory which will ultimately determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Wells may be completed that are assumed to be productive and actually deliver oil and natural gas in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. The evaluation of oil and natural gas leasehold acquisition costs requires managerial judgment to estimate the fair value of these costs with reference to drilling activity in a given area.

The successful efforts method of accounting can have a significant impact on the operational results reported when we enter a new exploratory area in hopes of finding an oil and natural gas field that will be the focus of future developmental drilling activity. The initial exploratory wells may be unsuccessful and will be expensed. Seismic costs can be substantial which will result in additional exploration expenses when incurred.

Industry Environment

We operate entirely within the United States, a mature region for the exploration and production of oil and gas. As a mature region, the size and frequency of new discoveries is declining, while finding and development costs are increasing.

We believe that there remain certain areas in the southern Mid-continent region which are under-explored or have not been fully explored and developed with the benefit of newly available exploration, production and reserve enhancement technology. Examples of such technology include advanced 3-D seismic processing, hydraulic reservoir fracture stimulation, advances in well logging and analysis, and enhanced oil recovery practices.

Another characteristic of a mature region is the historical exit of larger independent producers and major oil companies from such regions. These companies, searching for larger new discoveries, have ventured increasingly overseas and offshore, de-emphasizing their onshore United States assets. This movement out of mature basins by larger companies has provided acquisition opportunities for companies that are capable of

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quickly analyzing opportunities, well positioned financially to quickly close an acquisition, and have the technical expertise to generate additional value from these assets.

In other situations, larger independent producers and major integrated oil companies have allowed smaller companies the opportunity to explore and develop reserves on their undeveloped acreage through joint ventures and farm-in arrangements.

We believe the acquisition market for natural gas properties has become extremely competitive as producers vie for additional production and expanded drilling opportunities. During the last fiscal year, leasehold acquisition values reached historic highs. While these prices have moderated with the decline in natural gas commodity prices, we expect these values to increase in the near future. As natural gas demand rebounds, we expect drilling and service costs pressures to increase, resulting in higher finding and development costs. In addition, we expect lease-operating expenses to continue to rise as producers are forced to make operational enhancements to maintain production in aging fields.

Crude oil and natural gas are commodities that are traded on regulated markets. The price that we receive for the crude oil and natural gas we produce is largely a function of market supply and demand. Demand for natural gas in the United States has increased dramatically over the last ten years. Demand is impacted by general economic conditions, estimates of gas in storage, weather and other seasonal conditions, including hurricanes and tropical storms. Demand for crude oil has also increased over the last ten years while the increase in supply has not increased proportionately resulting in a tight market. Market conditions involving over or under supply of crude oil and natural gas can result in substantial price volatility. Historically, commodity prices have been volatile and we saw extreme volatility during the last fiscal year. We expect the volatility to continue in the future. A substantial or extended decline in oil and gas prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of oil and gas reserves that may be economically produced and our ability to access capital markets.

We derive our revenues from the sale of crude oil and natural gas that is produced from our properties. Revenues are a function of the volume produced and the prevailing market price at the time of sale. The price of oil and natural gas is the primary factor affecting our revenues.

Principal Components of Our Cost Structure

Direct Operating Expenses. These are day-to-day costs incurred to bring hydrocarbons out of the ground and to the market together with the daily costs incurred to maintain our producing properties. Such costs also include work-over repairs to our oil and gas properties not covered by insurance. To minimize and help control our costs, we acquired a work-over drilling rig and a swab rig in June of 2007. During the March 31, 2009 we purchased and began refurbishing a shallow well oil drilling rig which will be used to drill our Corsicana Nacatoch and Pecan Gap wells.

Production and Ad Valorem Taxes. These costs are primarily paid based on a percentage of market prices or at fixed rates established by federal, state or local taxing authorities.

Exploration Expense. The costs include geological and geophysical costs, seismic costs, delay rentals and the costs of unsuccessful wells or dry holes. While our current asset mix requires a minimum of geological and geophysical costs and seismic costs, it is possible this component of our cost structure could sharply increase depending upon future property acquisitions.

Plugging Costs. The Corsicana field is over one hundred years old and has hundreds of abandoned well bores scattered throughout the properties. In order to properly execute our enhanced oil recovery projects, we need to plug these abandoned, worn out well bores. Since the wells are fairly shallow, we are able to cement in the entire well bore at a cost of less than $1,500 per well.

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General and Administrative Expenses. Overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of finding our working interest partners, costs of managing our production and development operations, audit and other professional fees and legal compliance are included in general and administrative expense. General and administrative expense includes stock-based compensation expense (non-cash) associated with the adoption of SFAS No. 123(R), amortization of restricted stock grants as part of employee compensation.

Interest. We increased our levels of debt during fiscal year 2009, and in the future, we may finance a larger portion of our working capital requirements and acquisitions with borrowings under a credit facility or with longer-term public traded debt securities. As a result, interest expense could become a much more prevalent component of our cost structure.

Depreciation, Depletion and Amortization. As a successful efforts company, we capitalize all costs associated with our acquisition and all successful development and exploration efforts, and apportion these costs to each unit of production through depreciation, depletion and amortization expense. This also includes the systematic, monthly depreciation of our oilfield equipment assets.

Changes in Estimates. Changes in estimates of proved reserves significantly impact the depletion expense we record each year. When proved reserves increase, our depletion rate decreases, resulting in a lower depletion expense and higher net income. Conversely, as proved reserves decrease, our depletion rate increases, resulting in a higher depletion expense and lower net income. Changes in estimates of proved reserves are frequently the result of changes in commodity prices, changes in operating costs, and reservoir performance history. While depletion is a non-cash expense, volatility in commodity prices and the resulting volatility in depletion can have a material impact on our profitability and on certain leverage ratios.

Income Taxes. We are subject to federal income taxes but are currently not in a tax paying position for regular federal income taxes, primarily due to the current deductibility of intangible drilling costs ("IDC"). Currently, we are not subject to state income taxes. Virtually all of our Federal taxes are deferred; however, at some point, we will utilize all of our net operating loss carry-forwards and we will recognize current income tax expense and continue to recognize current tax expense as long as we are generating taxable income.

Results and Analysis of Financial Condition, Cash Flows and Liquidity

Barnett Shale Project: During the fiscal year ended March 31, 2009, we completed the seven wells that were awaiting completion at the beginning of the fiscal year. We also drilled and completed six wells. At year-end, there were two wells drilled and awaiting completion. ReoStar retained an average working interest in these wells of 51.75% at a total net investment of $6.5 million.

Corsicana Project: We continued injecting surfactant polymer in phase I of the polymer project. We drilled 16 wells for phase II of the polymer project at a total net investment of $600,000. Rather than permit phase II wells individually, we applied for an area injection permit. At the end of the fiscal year, the permit had not yet been approved by the regulatory authorities. We will begin injection in phase II upon approval of the area wide injection permit.

We drilled two unsuccessful exploratory wells in Corsicana, one Pecan Gap test well and one Glen Rose test well. We sold 50% working interests in the wells to industry partners under a turn-key contract. Our dry hole costs associated with these wells was minimal based on the terms of the associated drilling contracts.

In December 2008, we drilled two successful Pecan Gap wells in the Corsicana area at a total net investment of $268,000. We retained a 50% working interest in these wells.

The average price per barrel of oil during the fiscal year was $89.44 compared with $80.48 for the fiscal year ended March 31, 2008. The average price realized per thousand cubic feet (MCF) of gas produced during the fiscal year was $5.27 compared with $6.25 fiscal year ended March 31, 2008

Oil and gas production for the year increased 35% to a total of 124,968 BOE compared with 92,193 BOE 67,821 for the fiscal year ended March 31, 2008. Oil and gas revenue for the year increased 33% to a total of $6.5 million compared to $4.9 million for the fiscal year ended March 31, 2008. We had a net loss of $2.0 million for the fiscal year compared to net income of $796,000 for the prior fiscal year.

During fiscal year ended March 31, 2009, our cash provided from operations was $825,000 and we invested $10 million on capital expenditures. Financing activities provided net cash of $9.0 million. The Company entered into a $25 million senior secured credit facility with an initial borrowing base of $14 million. The Company borrowed $9.8 million against the borrowing base during the fiscal year ended March 31, 2009.

On March 31, 2009, we had $426,000 in cash and total assets of $23.0 million. Debt consisted of payables to non-related parties of $9.1 million, of which $9.0 million were long-term note payables. We also had accounts and notes payables to related parties of $3.6 million.

Cash is required to fund capital expenditures necessary to offset inherent declines in production and reserves.. Future success in growing reserves and production will be highly dependent on capital resources available and the success of finding or acquiring additional reserves.

We are in the process of securing additional capital financing. The additional financing may be in the form of additional equity, which would be dilutive to current shareholders. The financing may be in the form of a convertible debt instrument and the conversion feature would be dilutive to current shareholders. The additional financing could be a hybrid of the two. The proceeds of the financing will be used to close the acquisition of the South Texas leasehold, stage 1 of the South Texas drilling program, funding the fiscal year 2010 capital expenditure program in the Barnett Shale properties, refinancing the related party debt, and working capital.

Cautionary Statement: There can be no assurance that we will be successful in raising capital, whether in the form of equity, convertible debt, or a combination of the two. Even if we are successful in raising capital through the sources specified, there can be no assurances that any such financing would be available in a timely manner or on terms acceptable to our management and current shareholders. Additional equity financing will be dilutive to our then existing shareholders, and any debt financing could involve restrictive covenants with respect to future capital raising activities and other financial and operational matters.

Long-term cash flows are subject to a number of variables including the level of production and prices as well as various economic conditions that have historically affected the oil and gas business. A material drop in oil and gas prices or a reduction in production and reserves would reduce our ability to fund capital expenditures, meet financial obligations and/or remain profitable. We operate in an environment with numerous financial and operating risks, including, but not limited to, the inherent risks of the search for, development and production of oil and gas, the ability to buy properties and sell production at prices which provide an attractive return and the highly competitive nature of the industry. Our ability to expand our reserve base is, in part, dependent on obtaining sufficient capital through internal cash flow, bank borrowings or the issuance of debt or equity securities. There can be no assurance that internal cash flow and other capital sources will provide sufficient funds to maintain capital expenditures that we believe are necessary to efficiently develop our properties and offset inherent declines in production and proved reserves.

Cash Flow

Our principal sources of cash are net cash generated by oil and gas operations, the sale of a portion of the working interest in our drilling projects, and the issuance of equity or debt securities. Our operating cash flow is highly dependent on oil and gas prices.

Based on current projections and oil and gas futures prices, the 2010 capital program is expected to be funded with the proceeds of the senior secured credit facility, internal cash flow, and the planned capital financing.

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Capital Requirements

Our primary needs for cash are for exploration and development of our Barnett Shale properties, establishing the enhanced oil recovery project the Pecan Gap drilling program in our Corsicana properties, and the acquisition of additional oil and gas properties, both in unconventional gas plays and re-development of mature fields. During the three months ended March 31, 2007, $4.5 million of capital was expended on Barnett Shale drilling projects, during the fiscal year ended March 31, 2008, $18.2 million of capital was expended on Barnett Shale drilling projects, and during the fiscal year ended March 31, 2009, $12 million of capital was expended on Barnett Shale drilling. For fiscal year 2008, $12.2 million of the capital program was funded via the sale of working interests on a turn-key basis and the balance of the capital program was funded by cash flow from operations and the proceeds of the private placement. For fiscal year 2009, $6.6 million of the capital program was funded via the sale of working interests on a turn-key basis and the balance of the capital program was funded by cash flow from operations and the proceeds of the senior secured credit facility.

We repurchased working interests in several of our Barnett properties during fiscal year 2009 for a total cost of $0.4 million.

Our capital expenditure budget for fiscal year 2010 is $27.5 million. Of this, $20 million is budgeted for the acquisition and stage I drilling of the 13,000 acres in south Texas, $7 million is budgeted for drilling in the Barnett Shale, and $0.5 million is budgeted for the Corsicana surfactant polymer project expansion and Pecan Gap drilling program. Our capital expenditure budget will be partially funded from our credit facility and cash flow from the properties. The majority of the capital expenditure budget will be funded from a planned equity financing.

Future Commitments

In addition to our capital expenditure program, we are committed to making cash payments in the future on two types of contracts: note agreements and operating leases. As of March 31, 2009, we do not have any capital leases nor have we entered into any material long-term contracts for equipment, nor do we have any off-balance sheet debt or other such unrecorded obligations.

The table below provides estimates of the timing of future payments that we are obligated to make based on agreements in place at March 31, 2008. In addition to the contractual obligations listed on the table below, our balance sheet at March 31, 2008 reflects accrued interest payable on our debt of $109,000 which is payable throughout the rest of 2008.

	Fiscal year ended March 31			
In thousands	2010	2011	2012	Thereafter
Office Lease	$ 131,000	$ -	$ -	$ -
Senior Credit Facility	-	-	9,800,000	-
Related Party Notes	-	-	-	3,518,924

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements to enhance liquidity and capital resource position, or for any other purpose.

Inflation and Changes in Prices

Our revenues, the value of our assets and our ability to obtain bank loans or additional capital on attractive terms have been and will continue to be affected by changes in oil and gas prices and the costs to produce our reserves. Oil and gas prices are subject to significant fluctuations that are beyond our ability to control or predict. Although certain of our costs and expenses are affected by general inflation, inflation does not

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normally have a significant effect on our business. In a trend that began in 2004 and accelerated during 2008 and 2009, commodity prices for oil and gas increased significantly. The higher prices led to increased activity in the industry and, consequently, sharply rising costs. These costs trends have put pressure not only on our operating costs but also on our capital costs.

Management's Discussion of Critical Accounting Estimates

Our discussion and analysis of our financial condition and results of operations are based upon consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at year-end and the reported amounts of revenues and expenses during the year. We base our estimates on historical experience and various other assumptions that we believe are reasonable; however, actual results may differ.

Certain accounting estimates are considered to be critical if (a) the nature of the estimates and assumptions is material due to the level of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to changes; and (b) the impact of the estimates and assumptions on financial condition or operating performance is material.

Oil and Gas Properties

To ensure the reliability of our reserve estimates, we engage independent petroleum consultants to prepare an estimate of proved reserves. Proved the SEC defines reserves as those volumes of crude oil, condensate, natural gas liquids and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable from known reservoirs under existing economic and operating conditions. Proved developed reserves are volumes expected to be recovered through existing wells with existing equipment and operating methods. Although our engineers are knowledgeable of and follow the guidelines for reserves established by the SEC, the estimation of reserves requires engineers to make a significant number of assumptions based on professional judgment. Reserve estimates are updated at least annually and consider recent production levels and other technical information. Estimated reserves are often subject to future revisions, which could be substantial, based on the availability of additional information, including: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price and cost changes and other economic factors. Changes in oil and gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserve quantities. Reserve revisions in turn cause adjustments in the depletion rates utilized by us. We cannot predict what reserve revisions may be required in future periods.

We monitor our long-lived assets recorded in property, plant and equipment in our consolidated balance sheet to ensure they are fairly presented. We must evaluate our properties for potential impairment when circumstances indicate that the carrying value of an asset could exceed its fair value. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Such events include a projection of future oil and natural gas sales prices, an estimate of the ultimate amount of recoverable oil and gas reserves that will be produced from a field, the timing of future production, future production costs, future abandonment costs, and future inflation. The need to test a property for impairment can be based on several factors, including a significant reduction in sales prices for oil and/or gas, unfavorable adjustment to reserves, physical damage to production equipment and facilities, a change in costs, or other changes to contracts, environmental regulations or tax laws. All of these factors must be considered when testing a property's carrying value for impairment. We cannot predict whether impairment charges may be required in the future. We are required to develop estimates of fair value to allocate purchase prices paid to acquire businesses to the assets acquired and liabilities assumed under the purchase method of accounting. The purchase price paid to acquire a business is allocated to its assets and liabilities based on the estimated fair values of the assets acquired and liabilities assumed as of the date of acquisition. We use all available information to make these fair value determinations. See Note 3 to the consolidated financial statements for information on these acquisitions.

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Deferred Taxes

We are subject to income and other taxes in all areas in which we operate. When recording income tax expense, certain estimates are required because income tax returns are generally filed many months after the close of a calendar year, tax returns are subject to audit, which can take, years to complete and future events often impact the timing of when income tax expenses and benefits are recognized. We have deferred tax assets relating to tax operating loss carry forwards and other deductible differences. We routinely evaluate deferred tax assets to determine the likelihood of realization. A valuation allowance is recognized on deferred tax assets when we believe that certain of these assets are not likely to be realized. In determining deferred tax liabilities, accounting rules require OCI to be considered, even though such income or loss has not yet been earned.

At year-end 2009, deferred tax liabilities exceeded deferred tax assets by $1.7 million. We may be challenged by taxing authorities over the amount and/or timing of recognition of revenues and deductions in our various income tax returns. Although we believe that we have adequately provided for all taxes, gains or losses could occur in the future due to changes in estimates or resolution of outstanding tax matters.

Contingent Liabilities

A provision for legal, environmental and other contingent matters is charged to expense when the loss is probable and the cost or range of costs can be reasonably estimated. Judgment is often required to determine when expenses should be recorded for legal, environmental and contingent matters. In addition, we must often estimate the amount of such losses. In many cases, our judgment is based on the input of our legal advisors and on the interpretation of laws and regulations, which can be interpreted differently by regulators and/or the courts. We monitor known and potential legal, environmental and other contingencies and make our best estimate of when to record losses for these matters based on available information. Although we continue to monitor all contingencies closely, particularly our outstanding litigation, we currently have no material accruals for contingent liabilities.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Not applicable.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
ReoStar Energy Corporation
Fort Worth, Texas 76107

We have audited the accompanying consolidated balance sheets of ReoStar Energy Corporation as of March 31, 2009 and 2008, and the related consolidated statements of operations, stockholders' equity, and cash flows for the years then ended. ReoStar Energy Corporation's management is responsible for these consolidated financial statements. 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The company 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 also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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 financial position of ReoStar Energy Corporation as of March 31, 2009 and 2008, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

/s/ Killman, Murrell & Company, P.C.
Killman, Murrell & Company, P.C.
Odessa, Texas
June 12, 2009

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ReoStar Energy Corporation
Consolidated Balance Sheets

	March 31, 2009	March 31, 2008
ASSETS		
Current Assets:		
Cash	$ 426,430	$ 592,665
Accounts Receivable:		
Oil & Gas - Related Party	337,879	868,406
Related Party	1,107,854	-
Other	15,760	-
Inventory	7,514	4,748
Other Current Assets	6,317	13,062
Total Current Assets	1,901,754	1,478,881
Note Receivable	553,536	1,355,228
Oil and Gas Properties - successful efforts method	25,254,777	17,832,931
Less Accumulated Depletion and Depreciation	(6,206,558)	(4,139,337)
Oil & Gas Properties (net)	19,048,219	13,693,594
Other Depreciable Assets:	2,171,654	1,641,806
Less Accumulated Depreciation	(315,093)	(121,113)
Other Depreciable Assets (net)	1,856,561	1,520,693
Other Related Party Receivable	-	80,395
Leasehold Held for Sale	150,000	1,680,813
Investment in Equity Method Investment	-	142,395
Total Assets	$ 23,510,070	$ 19,951,999
LIABILITIES		
Current Liabilities:		
Accounts Payable	$ 22,033	$ 103,479
Notes Payable to Related Parties	-	324,330
Payable to Related Parties	148,550	1,547,136
Accrued Expenses	106,141	915,372
Accrued Expenses - Related Parties	130,870	171,788
Current Portion of Long-Term Debt	-	14,960
Total Current Liabilities	407,594	3,077,065
Notes Payable	8,955,202	1,647,769
Notes Payable - Related Parties	3,518,924	3,194,594
Other Related Party Payables	-	490,840
Less Current Portion of Notes Payable	-	(14,960)
Total Long-Term Debt	12,474,126	5,318,243
Asset Retirment Obligation	344,079	-
Deferred Tax Liability	1,702,782	2,163,183

Total Liabilities		14,928,581		10,558,491
Commitments & Contingencies:				
Contingent Stock Based Compensation		-		214,976
Stockholders' Equity				
Common Stock, $.001 par,200,000,000 shares authorized and 80,353,912 and 80,181,310 shares outstanding on March 31, 2009 and 2008, respectively		80,353		80,181
Additional Paid-In-Capital		10,959,965		9,553,346
Retained Deficit		(2,458,829)		(454,995)
Total Stockholders' Equity		8,581,489		9,178,532
Total Liabilities & Stockholders' Equity	$	23,510,070	$	19,951,999

See Accompanying Notes to Consolidated Financial Statements

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ReoStar Energy Corporation
Consolidated Statements of Operations

	Years Ended	
	Mar. 31, 2009	**Mar. 31, 2008**
Revenues		
Oil & Gas Sales	$ 6,558,069	$ 4,902,072
Sale of Leases	18,005	307,028
Other Income	458,365	281,231
	7,034,439	5,490,331
Costs and Expenses		
Oil & Gas Lease Operating Expenses	2,598,208	2,125,261
Workover Expenses	114,683	356,342
Severance & Ad Valorem Taxes	427,307	318,785
Geologic & Geophysical	-	8,993
Delay Rentals	2,975	52,186
Plugging Costs & Expired Leases	433,976	290,959
Depletion & Depreciation	3,487,440	1,520,406
General & Administrative:		
Salaries & Benefits	874,418	1,104,785
Legal & Professional	720,771	584,765
Other General & Administrative	701,687	332,009
Interest, net of capitalized interest of $537,024 and $488,299 for the years ended March 31, 2009 and March 31, 2008, respectively	3,780	-
	9,365,245	6,694,491
Other Income (Expense)		
Interest Income	79,876	210,938
Other Expense	(6,745)	(16,938)
Loss on Equity Method Investments	(206,561)	(32,605)
(Loss) from continuing operations before income taxes and discontinued operations	(2,464,236)	(1,042,765)
Income Tax Benefit	460,402	364,930
Loss before discontinued operations	(2,003,834)	(677,835)
Income from discontinued operations, net of income taxes:		
Pipeline Income	-	22,930
Gain on Sale of Pipeline	-	1,450,805
Income from discontinued operations	-	1,473,735
Net Income (Loss)	$ (2,003,834)	$ 795,900
Basic & Diluted (Loss) Income per Common Share:		
Loss from continuing operations	$ (0.02)	$ (0.01)
Income from discontinued operations	$ -	$ 0.02)
Net Income (Loss) per Common Share	$ (0.02)	$ 0.01

Weighted Average Common Shares Outstanding	80,300,804	78,800,618

See Accompanying Notes to Consolidated Financial Statements

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ReoStar Energy Corporation
Consolidated Statements of Stockholders' Equity
Years Ended March 31, 2008 and 2009

	Common Stock				
	Number of Shares	Amount	Paid-In Capital	Retained Deficit	Total
Balance, March 31, 2007	71,954,262	$ 71,954	$ 1,970,795)	$ (1,250,895)	$ 791,854)
Sale of Common Stock	7,637,048	7,637	6,877,717	-	6,885,354
Common Stock Issued for Wilson Energy Acquisition	240,000	240	298,560	-	298,800
Common Stock Issued for Employee Compensation	350,000	350	406,274	-	406,624
Net Income 2008	-	-	-	795,900	795,900
Balance, March 31, 2008	80,181,310	80,181	9,553,346	(454,995)	9,178,532
Common Stock Issued for Penalty Shares	172,602	172	172,430	-	172,602
Warrants Issued for short-term note payable	-	-	36,967	-	36,967
Warrants Issued in connection with consulting contract	-	-	300,000	-	300,000
Warrants Issued for success fee related to senior secured credit facility	-	-	375,000	-	375,000
Employee and director stock options granted	-	-	522,222	-	522,222
Net Loss 2009	-	-	-	(2,003,834)	(2,003,834)
Balance, March 31, 2009	80,353,912	$ 80,353	$ 10,959,965	$ (2,458,829)	$ 8,581,489

See Accompanying Notes to Consolidated Financial Statements

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ReoStar Energy Corporation
Consolidated Statements of Cash Flows

	Fiscal Year Ended	
Operating Activities:	**Mar. 31, 2009**	**Mar. 31, 2008**
Net Income (Loss)	$ (2,003,834)	$ 795,900
Adjustments to reconcile net income to net cash from operating activities:		
Discontinued Operations	-	(22,930)
Deferred Income Tax Expense	(460,402)	(364,930)
Depletion, Depreciation, & Amortization	3,487,440	1,520,406
Expired Leases	433,976	280,400
Non-employee stock based compensation	300,000	-
Stock based compensation	307,240	621,600
Penalty shares	172,602	-
Loss on Equity Method Investment	206,561	32,605
Gain on Sale of Pipeline (net of income taxes)	-	(1,450,805)
Gain on Leases Sold	-	(307,028)
Changes in Operating Assets and Liabilities		
Changes in Accrued Liabilities	(685,671)	25,514
Change in Inventory	(2,766)	(4,748)
Change in Related Party Receivables/Payables	(1,369,752)	(10,000)
Changes in Other Receivables	(15,760)	63,389
Changes in Other Current Assets	6,745	(13,062)
Change in Revenue Receivables	530,527	(373,206)
Changes in Accounts Payable	(81,446)	(406,061)
Net Cash provided by (used in) Operating Activities	825,460	387,044
Net Cash provided by (used in) Discontinued Operations	-	79,373
Investing Activities:		
Oil & Gas Drilling, Completing and Leasehold Acquisition Costs	(8,706,952)	(7,748,556)
Change in Related Party Payable related to drilling	(1,547,136)	(2,073,212)
Proceeds from the Sale of Leases	-	412,913
Investment in Other Depreciable Assets	(534,287)	(1,641,806)
Investment in Equity Method Investment	(64,166)	(175,000)
Note Receivable Collections	801,692	258,990
Net Cash provided by (used in) Continuing Activities	(10,050,849)	(10,966,671)
Net Cash provided by (used in) Discontinued Activities	-	14,002,552
Financing Activities		
Financing Activities Notes Payable Advances Net of Loan Fees	10,401,254	54,898
Notes Payable Principal Payments	(1,342,100)	(2,153,066)
Changes in Notes Payable Related Party	-	(100,000)
Net cash received from common stock subscriptions	-	6,885,353
Net Cash provided by (used in) Continuing Activities	9,059,154	4,687,185
Net Cash provided by (used in) Discontinued Activities	-	(7,809,073)
Net Increase (Decrease) in Cash	(166,235)	380,410
Cash - Beginning of the Year	592,665	212,254
Cash - End of the Year	$ 426,430	$ 592,664

See Accompanying Notes to Consolidated Financial Statements

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ReoStar Energy Corporation
Consolidated Statements of Cash Flows
(Continued)

	Year Ended	
	Mar. 31, 2008	**Mar. 31, 2008**
Supplemental Disclosure of Cash Flow Information		
Cash paid during period for:		
Interest	$ 466,792	$ 204,217
Income Taxes	$ -	$ -
Non Cash Investing and Financing Activities		
Stock Based Property Acquisition	$ -	$ 298,800
Stock Based Loan Costs	$ 375,000	$ -
Stock Based Interest Payment	$ 36,967	$ -
Stock Based Compensation	$ 522,222	$ 406,624
Stock Based Consulting Fees	$ 300,000	$ -

See Accompanying Notes to Consolidated Financial Statements

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REOSTAR ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
MARCH 31, 2009 AND 2008

(1) SUMMARY OF ORGANIZATION AND NATURE OF BUSINESS

REOSTAR ENERGY CORPORATION ("REOSTAR ," "we," "us," or "our") is engaged in the exploration, development and acquisition of oil and gas properties primarily in Texas. We seek to increase our reserves and production primarily through drilling, complementary acquisitions, and the development of enhanced oil recovery prospects.

(2) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation and Principles of Consolidation

The financial statements and notes are representations of the Company's management who are responsible for their integrity and objectivity. The Company's accounting policies conform to accounting principles generally accepted in the United States of America and have been consistently applied in the preparation of these consolidated financial statements.

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries, ReoStar Leasing, Inc. and ReoStar Gathering, Inc. Intercompany accounts and transactions have been eliminated in consolidation.

Use of Estimates

The preparation of financial statements in accordance with generally accepted accounting principles ("GAAP") in the United States requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at year-end and the reported amounts of revenues and expenses during the year. Actual results could differ from the estimates and assumptions used.

Income per Common Share

Basic net income per share is calculated based on the weighted average number of common shares outstanding. Diluted net income per share assumes issuance of stock compensation awards and exercise of stock warrants, provided the effect is not anti-dilutive.

Revenue Recognition

Oil, gas, and natural gas liquids revenues are recognized when the products are sold and delivery to the purchaser has occurred. Although receivables are concentrated in the oil and gas industry, we do not view this an unusual credit risk.

Cash and Equivalents

Cash and cash equivalents include cash on hand and on deposit and investments in highly liquid debt instruments with maturities of three months or less.

Acounts Receivable

Accounts receivable include amounts that are due from oil and gas sales produced and sold during the reporting period but awaiting cash payment including related parties on oil and gas properties operated by the Company in the amounts of $337,879 and $868,406 for the years ended March 31, 2009 and 2008, respectively. Other related party receivables in connection with oil and gas activities were due the Company at March 31, 2009 in the amount of $1,107,854.

We regularly review our accounts receivable for quality of accounts receivable. Other than related party receivables, we accrue a provision for doubtful accounts equal to 20% of any accounts receivable balance that has aged more than one hundred twenty (120) days. As of March 31, 2009, we had no accounts receivable balances over the 120 day threshold, therefore, no allowance for doubtful accounts has been accrued.

Oil and Gas Properties

Oil and gas investments are accounted for by the successful efforts method of accounting. Accordingly, the costs incurred to acquire property (proved and unproved), all development costs, and successful exploratory costs are capitalized, whereas the costs of unsuccessful exploratory wells are expensed.

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Depletion of capitalized oil and gas well costs is provided using the units of production method based on estimated proved developed oil and gas reserves of the respective oil and gas properties. Cost, net of estimated salvage value, is recovered on each property via depletion.

The carrying value of capitalized oil and gas property costs is compared annually to the future net revenues attributed to the related proved developed oil and gas reserves. If such costs exceed the future net revenues of the related proved oil and gas reserves, an impairment provision is recorded in accordance with the FASB SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets".

Our policy is to minimize risks associated with drilling exploratory wells by selling most of the working interest associated with each particular well on a turn-key basis (up to 80% of the working interest may be sold). The proceeds are credited to the net book value of the property. In the event the proceeds from selling the working interest exceed the total cost of acquiring the leasehold and drilling the well, we record the net proceeds in excess of cost as gain on the sale of oil and gas properties.

Gain or loss is recognized from the sale of any interest of proven developed properties.

Depletion
Our proven oil and gas properties are depleted using a field level cost center. A field is defined as an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas of interest, etc. A reservoir is defined as a porous and permeable underground formation containing a natural accumulation of producible oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

If all the oil and gas properties in a field-wide cost center are proven properties, then all of the leasehold costs will be aggregated and depleted on a units-of-production basis over the total proved reserves of the field. If the cost center contains some properties that are proved and some properties that are unproved, only the proved property leasehold costs are aggregated and depleted. The total capitalized costs for wells and equipment is also aggregated and depleted on a units-of-production basis over the total proved developed reserves of the field.

Depreciation
The workover, service, and swab rigs are depreciated using the straight-line method over the estimated useful life of 10 years. Computer equipment is depreciated using the straight-line method over the estimated useful life of 3 years. All other equipment is depreciated using the straight-line method over 5 years.

Interest Expense
ReoStar capitalizes interest expense related to the financing obtained to acquire and develop oil and gas properties. Capitalized interest associated with oil and gas properties is recovered via depletion, using the overall depletion rate on producing properties. Capitalized interest for the years ended March 31, 2009 and 2008 have been included in Other Depreciable Assets in the amounts of $999,620 and $930,408.

Deferred Taxes
Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to the differences between the financial statement carrying amounts of assets and liabilities and their tax bases as reported in our filings with the respective taxing authorities. The realization of deferred tax assets is assessed periodically based on several interrelated factors. These factors include our expectation to generate sufficient taxable income including tax credits and operating loss carryforwards.

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Stock-based Compensation
The Company accounts for its stock options and warrants in accordance with FAS 123(R) - Share Based Payments, and related interpretations in accounting for stock-based compensation awards to employees, directors, and non-employees. In accordance with FAS 123 (R), the Company recognizes stock-based compensation expense based on the fair value of the stock options (or warrants) on the date of grant. The fair value of the stock options (or warrants) at the date of grant is amortized over the vesting period, with the offsetting credit to additional paid in capital. If the stock options are exercised, the proceeds are credited to share capital. Likewise, if the stock warrants are exercised, the proceeds are credited to share capital.

Comprehensive Income
SFAS No. 130, "Reporting Comprehensive Income," establishes standards for reporting and financial statement presentation of comprehensive income, its components and accumulated balances. Comprehensive income is defined to include all changes in equity except those resulting from investments by owners and distributions to owners. Among other disclosures, SFAS No. 130 requires that all items that are required to be recognized under current accounting standards as components of comprehensive income be reported in a financial statement that is displayed with the same prominence as other financial statements. The Company does not have comprehensive income items requiring disclosure of comprehensive income.

Impairment of Long-Lived Assets
In accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, long lived assets, such as oil and gas properties and equipment are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated future cash flows, an impairment charge is recognized by the amount by which the carrying amount of the asset exceeds the fair value of the asset. Assets to be disposed of would be separately presented in the balance sheet and reported at the lower of the carrying amount of the fair value less costs to sell and are no longer depreciated. The assets and liabilities of a disposed group classified as held for sale would be presented separately in the appropriate asset and liability sections of the balance sheet.

Contingencies
Certain conditions may exist as of the date the financial statements are issued, which may result in a loss to the Company, but which will only be resolved when one of more future events occur or fail to occur. The Company's management and legal counsel assess such contingent liabilities, and such assessment inherently involves an exercise of judgment. In assessing loss contingencies related to legal proceedings that are pending against the Company, or unasserted claims that may result in such proceedings, the Company's legal counsel evaluates the perceived merits of any legal proceedings or unasserted claims as well as the perceived merits of the amount of relief sought or expected to be sought therein.

If the assessment of a contingency indicates that it is probable that a material loss has been incurred and the amount of the liability can be estimated, the estimated liability is accrued in the Company's financial statements. If the assessment indicates that a potentially material loss contingency is not probable but is reasonably possible, or is probable but cannot be estimated, then the nature of the contingent liability, together with an estimate of the range of possible loss if determinable and material, is disclosed.

Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the guarantees are disclosed.

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Financial Instruments
The carrying amount of financial instruments including cash and cash equivalents, accounts receivable, note receivable, accounts payable and accrued liabilities approximate fair value, unless otherwise stated, as of March 31, 2009. The carrying amount of long-term debt approximates market value due to the use of market interest rates.

Fair value estimates of financial instruments are made at the period end based on relevant information about financial markets and specific financial instruments. As these estimates are subjective in nature, involving uncertainties and matters of significant judgment, they cannot be determined with precision. Changes in assumptions can significantly affect estimated fair value.

Asset Retirement Obligation
Our financial statements reflect the fair value for asset retirement obligation, which consist of estimated future plugging and abandonment expenditures related to our oil and gas properties, to the extent they can be reasonably estimated. The asset retirement obligation is recorded as a liability at its estimated present value at the asset's inception, with an offsetting increase to producing properties on the consolidated balance sheet. Periodic accretion of the discount of the estimated liability is recorded as an expense in the consolidated statements of operations.

Reclassifications
Certain reclassifications have been made to the consolidated financial statements for March 31, 2008 to conform to the presentation used for the 2009 consolidated financial statements.

Recent Accounting Pronouncements
In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements - an amendment of Accounting Research Bulletin No. 51*. This statement requires an entity to separately disclose non-controlling interests as a separate component of equity in the balance sheet and clearly identify on the face of the income statement net income related to non-controlling interests. This statement is effective for financial statements issued for fiscal years beginning after December 15, 2008. The adoption of this statement will not have a material impact on our financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 141 (R), *Business Combinations*. This statement requires assets acquired and liabilities assumed to be measured at fair value as of the acquisition date, acquisition-related costs incurred prior to the acquisition to be expensed and contractual contingencies to be recognized at fair value as of the acquisition date. This statement is effective for financial statements issued for fiscal years beginning after December 15, 2008. We will comply with this statement prospectively in accounting for future business combinations.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities - an amendment of FASB Statement No. 133*. This statement changes the disclosure requirements for derivative instruments and hedging activities. The statement requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. This statement will not have a material impact on our financial disclosures.

In May 2008, the FASB issued FSP APB 14-1, *Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (Including Partial Cash Settlement)*. FSP APB 14-1 clarifies that convertible debt instruments that may be settled in cash upon either mandatory or optional conversion (including partial cash settlement) are not addressed by paragraph 12 of APB Opinion No. 14, *Accounting for Convertible Debt and Debt Issued with Stock Purchase Warrants*. The accounting prescribed by FSP APB 14-1 increases the amount of interest expense required to be recognized with respect to such instruments and, thus, lowers reported net income and net income per share of issuers of such instruments. Issuers must account for the liability and equity components of the instrument separately, and in a manner that reflects interest expense at the interest rate of similar nonconvertible debt. We have three debt series that will be affected by the guidance, our 2.75% Contingent Convertible Senior Notes due 2035, our 2.5% Contingent Convertible Senior Notes due 2037 and our 2.25% Contingent Convertible Senior Notes due 2038. This staff position is effective for financial statements issued for fiscal years and interim periods beginning after December 15, 2008 and must be applied on a retrospective basis. This statement will not have a material impact on our financial statements.

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In June 2008, the FASB issued FSP Emerging Issues Task Force (EITF) No. 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities*. FSP EITF 03-6-1 addresses whether instruments granted in share-based payments transactions are participating securities prior to vesting and therefore need to be included in the earnings allocation in calculating earnings per share under the two-class method described in SFAS No. 128, *Earnings per Share*. FSP EITF No. 03-6-1 requires companies to treat unvested share-based payment awards that have non-forfeitable rights to dividend or dividend equivalents as a separate class of securities in calculating earnings per share. FSP EITF No. 03-6-1 is effective for fiscal years beginning after December 15, 2008; earlier application is not permitted. FSP EITF No. 03-6-1 could be applicable to us, but we have no current transactions that would be affected.

In October 2008, the FASB issued FSP FAS 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active*. FSP FAS 157-3 clarifies the application of FASB statement No. 157, Fair Value Measurements, in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. This FSP could be applicable to us, but we currently have no financial assets of this type.

On December 31, 2008, the Securities and Exchange Commission (SEC) adopted major revisions to its rules governing oil and gas company reporting requirements. These include provisions that permit the use of new technologies to determine proved reserves, and allow companies to disclose their probable and possible reserves to investors. The current rules limit disclosure to only proved reserves. The new disclosure requirements also require companies to report the independence and qualifications of the person primarily responsible for the preparation or audit of reserve estimates, and to file reports when a third party is relied upon to prepare or audit reserves estimates. The new rules also require that oil and gas reserves be reported and the full-cost ceiling value calculated using an average price based upon the prior 12-month period. The new oil and gas reporting requirements are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009, with early adoption not permitted. We are in the process of assessing the impact of these new requirements on our financial position, results of operations, and financial disclosures.

(3) ACQUISITIONS AND DISPOSITIONS

Wilson Energy Transaction

Effective August 1, 2007, ReoStar purchased substantially all of the assets of Vern Wilson Energy, Inc. The assets consisted of 4 oil and gas leases located in Texas and Louisiana, a service rig, and an operating shop to assist in maintenance of field equipment. Consideration for the purchase consisted of $159,000 cash and 240,000 shares of ReoStar stock with a market value of $298,800 for a total purchase price of $457,800.

(4) DEFERRED TAX LIABILITY

Our income tax benefit from operations was $460,402 and $364,930 for the years ended March 31, 2009 and 2008, respectively. A reconciliation between the statutory federal income tax rate and our effective income tax rate is as follows: Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax provisions. Our income tax expense (benefit) is as follows:

	March 31,	
	2009	2008
Federal Statutory Tax Rate	35%	35%
State	0%	0%
Consolidated Effective Tax Rate	35%	35%

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax provisions. Our income tax expense (benefit) is as follows:

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	Years Ended March 31,			
		2009		2008
Current income tax expense				
Federal	$	-		-
State		-		-
Total current tax expense		-		-
Deferred income tax (benefit) from continuing operations				
Federal		(460,402)		(364,930)
State		-		-
Total income tax (benefit) from continuing operations		(460,402)		(364,930)
Income tax (expense) from discontinued operations		-		793,550
Total income tax (benefit) expense	$	(460,402)	$	428,620)

The income tax provision differs from the amount computed at the statutory rate of 35% as follows:

	Years Ended March 31,			
		2009		2008
Rate		35%		35%
Tax on Income from Continuing Operations at Statutory Rate	$	(862,483)	$	(364,968)
Increase (decrease) resulting from:				
Permanent differences		402,081		38
Income tax (benefit) from continuing operations		(460,402)		(364,930)
Income tax expense from discontinued operations		-		793,550
Income Tax (Benefit) Provision	$	(460,402)	$	428,620

Significant components of deferred tax assets and liabilities are as follows:

	March 31,			
		2009		2008
Deferred Tax Assets:				
Net Operating Loss Carryforward	$	751,045	$	2,188
Other Deferred Tax Assets		-		-
Total Deferred Tax Assets		751,045		2,188
Deferred Tax Liabilities				
Oil & Gas Properties Basis		2,086,984		1,922,321
Other Deferred Tax Liabilities		366,843		243,050
Total Deferred Liabilites		2,453,827		2,165,371
Net Deferred Tax Liability	$	1,702,782	$	2,163,183

At March 31, 2009 and 2008, we had net operating loss carryforwards for tax purposes of approximately $2.4 million and $6 thousand, and expire on March 31, 2028 and 2027, respectively,

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(5) EARNINGS PER COMMON SHARE

The average stock price for the year was less than the strike price of the outstanding stock warrants and stock options. Therefore, there were no dilutive common stock equivalents as of March 31, 2009. The following table sets forth the computation of basic earnings per common share.

	March 31,			
	2009		2008	
Numerator				
Net Income (Loss)	$	(2,003,834)	$	795,900
Denominator				
Weighted Average Shares Outstanding - Basic		80,300,804		78,800,618
Basic - Net Income	$	(0.02)	$	0.01

(6) INDEBTEDNESS

The following debt was outstanding as of March 31, 2009 and March 31, 2008, respectively:

Construction Loan. On October 2, 2007, ReoStar secured a $245,000 construction loan from Texas Capital Bank to partially finance the construction of a field office on a 10 acre parcel in Corsicana, Texas. The terms of the loan provide for 6 months of interest payments beginning November 1, 2007. Beginning May 1, 2008, the loan provides for 60 monthly payments equal to $1,360 plus interest. The loan provides for interest equal to the Wall Street Journal Prime Rate. The note provided for a balloon payment of $164,455 plus interest on May 1, 2013. Construction was completed in the summer of 2008 and the construction loan was paid in full on October 30, 2008 with proceeds from the Union Bank Senior Secured Credit Facility. The outstanding balance at March 31, 2008 was approximately $59,000.

Lease Notes Payable. The Company had several lease bank obligations related to the acquisition of certain leasehold in the Barnett Shale and the Fayetteville Shale plays. The first of the lease bank obligations related to acreage acquired in the Barnett Shale. The lease bank obligation originated on May 15, 2006 and bears interest of 10% due annually. The note matured June 1, 2008 and was paid in full in October 2008. The outstanding balance at March 31, 2008 was $72,100.

There were three additional lease bank obligations that related to the acquisition of acreage in the Fayetteville Shale. All three obligations were non-recourse in nature and required repayment of the principal as the acquired leasehold was drilled or when the underlying leasehold was sold. The Company has fully impaired the underlying acreage (see Note 10 for more information). Since the obligations are non-recourse in nature, the Company has written off the related lease bank obligations as of March 31, 2009. The outstanding balances at March 31, 2008 were $1,213,000.

Senior Secured Credit Facility. On October 30, 2008, we entered into a $25 million senior secured credit facility with lenders led by Union Bank of California, N.A. ("UBOC"), as administrative agent and as issuing lender. Pursuant to the terms of the senior credit facility, the initial borrowing base was set at $14 million and is subject to re-determination every six months with one optional re-determination allowed between scheduled re-determinations.

As of March 31, 2009, the Company had drawn $9,800,000 on the note. The Company incurred costs associated with the note (including legal fees and investment banking fees) of approximately $1.2 million. The loan fees are amortized over the life of the note, and amortization for the year totaled approximately $190 thousand. The carrying value of the note is reduced by the loan costs net of amortization, leaving a carrying balance of approximately $8,955,000.

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The credit facility is secured by all of the Company's assets and is senior to all other long-term debt. The outstanding principal is due October 30, 2011. However, if, pursuant to the terms of the senior credit facility, specific evens of default occur, the due date of all outstanding principal and accrued interest may be accelerated. Specific events of default include, but are not limited to: payment defaults; breaches of representations and warranties, and covenants; insolvency; a "change of control" in our ownership as described in the senior credit agreement; and a "material adverse change" as described in the senior credit agreement.

The senior credit facility requires us to comply with certain credit metrics, such as the maintenance of minimum working capital, certain ratios of debt to EBITDA (as defined in the senior credit facility), maintenance of a minimum EBITDA to interest, and places a cap on Capital Expenditures each year. Each metric is further defined below.

Working capital, defined as consolidated current assets less consolidated current liabilities is required to be at least $1.5 million as of the last day of each fiscal quarter. Current assets include the unused amount available under the senior credit facility. We were in compliance with the working capital requirement as of March 31, 2009.

The leverage ratio is as follows: (a) for each fiscal quarter, the ratio of (i) Funded Debt (as defined in the senior credit facility) to (ii) consolidated EBITDA for the four fiscal quarter period then ended must not be greater than 3.50 to 1.00. For the purposes of calculating the leverage ratio, the definition of "Funded Debt" does not include Notes Payable to Shareholders that has been subordinated to the senior credit facility. EBITDA is defined as Consolidated Net Income adjusted plus, to the extent deducted in determining net income, interest expense, income taxes, depletion, depreciation, amortization, and other non-cash charges for the period. We were not in compliance with the leverage ratio as of March 31, 2009. A waiver was granted by the lender for this specific instance of non-compliance. There can be no assurances that the lender will grant a waiver for such non-compliance of this or any covenant in the future.

The interest coverage ratio is the ratio of our consolidated EBITDA for the four fiscal quarter periods then ended to our consolidated Interest Expense for the four fiscal quarters then ended must be at least 3.00 to 1.00. We were in compliance with the interest coverage ratio as of March 31, 2009.

At our option, the interest rate is computed based on either (i) the prime rate plus the applicable margin ranging from 0.00% up to 0.50% based on the utilization level or (ii) the LIBOR rate applicable to the interest period plus the applicable margin ranging from 2.00% to 2.75% based on the utilization level. At March 31, 2009 the interest rate was 2.82%.

The senior credit agreement imposes certain restrictions on us and our subsidiaries, subject to specific exceptions, including, but not limited to, the following: (i) incurring additional liens; (ii) incurring additional debt; (iii) merging or consolidating or selling, transferring, assigning, farming-out, conveying or otherwise disposing of any property; (iv) making certain payments, including cash dividends to our stockholders; (v) making any loans, advances or capital contributions to, or making any investment in, or purchasing or committing to purchase any stock or other securities or interests in any person or any oil and natural gas properties or activities related to oil and natural gas properties unless with regard to new oil and natural gas properties, such properties are mortgaged to UBOC, as administrative agent, or with regard to new subsidiaries, such subsidiaries execute a guaranty, pledge agreement, security agreement and mortgage in favor of UBOC, as administrative agent; and (vi) entering into affiliate transactions on terms that are not at least as favorable to us as comparable arm's length transactions.

Notes Payable to Related Parties. ReoStar has a note payable to ReoStar's President and CEO. The note was renewed in October 2008 and matures on April 1, 2012. The note bears interest of 8%. The principal balance of the note on March 31, 2009 and 2008 was $324,330 and $324,330, respectively. The note is subordinated to the Union Bank Senior Secured Credit Facility.

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ReoStar has a note payable to a limited partnership owned by the Chairman of the Board. The note was renewed in October 2008 and matures on April 1, 2012. The note provides for an interest rate of 5.95%. The principal balance at March 31, 2009 and 2008 was $3,194,594 and $3,194,594, respectively. The note is subordinated to the Union Bank Senior Secured Credit Facility.

The following table summarizes our note payable repayment obligations.

	Fiscal Years Ending March 31,					
	2010	2011	2012	2013	Thereafter	Total
Note Payable - Shareholder	$ -	$ -	$ -	$ 324,330	$ -	$ 324,330
Note Payable - Shareholder	-	-	-	3,194,594	-	3,194,594
Senior Secured Credit Facility	-	-	9,800,000	-	-	9,800,000
	$ -	$ -	$ 9,800,000	$ 3,518,924	$ -	$ 13,318,924

Payables to Related Party.
ReoStar contracts with the operators of its oil and gas properties to drill and complete all new wells. The operators are affiliated entities owned by a ReoStar shareholder who owns more than 20% of ReoStar stock. The outstanding payable to the operators as of March 31, 2009 and 2008 was $148,550 and $1,547,136, respectively.

Additionally, ReoStar had other outstanding non-current payables to related parties of $0 and $490,840 at March 31, 2009 and 2008, respectively.

Accrued Expenses:
Accrued expenses consist of working interest owner payout guarantees totaling $0 and $748,963, accrued interest expense totaling $23,030 and $108,924, royalty payable totaling $68,406 and $57,485, and sales taxes payable totaling $14,705 and $0 at March 31, 2009 and 2008, respectively.

Accrued interest payable to related parties consisted of $130,870 and $171,788 on March 31, 2009 and 2008, respectively.

(7) CAPITAL STOCK
We have authorized capital stock of 200 million shares of common stock. The following is a schedule of changes in the number of outstanding common shares since March 31, 2007.

	Shares Outstanding
Shares Outstanding March 31, 2007	71,954,262
Private Placement shares issued	7,637,048
Shares issued for Vern Wilson Energy acquisition	240,000
Shares issued for employment compensation	350,000
Balance at March 31, 2008	80,181,310
Shares issued as penalty for late registration of private placement shares	172,602
	80,353,912

The Company issued shares via a private placement offering at $1.00 per share. The proceeds from the sale reported in the statement of stockholder's equity is net of offering expenses of $751,695. Each share had one warrant attached with a strike price of $1.50 per share. The warrants are scheduled to expire 2 years from the date the stock certificates are issued. The private placement subscription agreement provided for additional penalty shares to be issued in the event the stock was not registered with the Securities Exchange Commission within 90 days of subscription. During the year, the company issued 172,602 penalty shares because the registration was not completed within the specified time period for some, but not all, of

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the private placement subscriptions. The penalty stock was valued at $1.00 per share based upon the bid price on the relevant date and an expense of $172,602 was recorded for the year ended March 31, 2009.

In total, the Company issued 11,462,000 warrants in conjunction with the private placement offering in 2007. Of these, 6,605,000 warrants were scheduled to expire by March 31, 2009. The remaining 4,757,000 warrants were scheduled to expire in the quarter ending June 30, 2009. In April 2009, the Company extended the expiration date for all of the warrants to June 16, 2009.

There were stock option grants issued to members of ReoStar's Board of Directors of 100,000 shares outstanding at year end. The stock options were valued at $69,856 using the Black-Scholes model with a volatility of 183.59% and a strike price of $1.11. Of the stock options, one-third vested on March 31, 2008, one-third vested on March 31, 2009, and the balance will vest on March 31, 2010.

At March 31, 2008, there were 350,000 shares of unvested restricted stock granted to two of the Company's officers outstanding. In July 2008, the Board approved an employee stock option plan that provides for stock options up to 8,000,000 shares. The Board canceled the restricted stock grants and replaced them with stock options. Stock options were issued to three of the Company's officers totaling 2,500,000 shares. The options were granted on July 25, 2008 and were valued at $873,348 using the Black-Scholes model with a volatility of 194.44% and a strike price of $0.35 per share. Of the stock options, one-third vested on March 31, 2009, one-third will vest on March 31, 2010, and the balance will vest on March 31, 2011.

Salaries and Benefits expense included stock based compensation expense of $307,240 and $621,600 for the years ended March 31, 2009 and 2008, respectively.

The Company issued 1,250,000 warrants to purchase 1 share of stock to our investment banking firm as part of the success fee in closing the Union Bank of California senior secured credit facility. The warrants were issued October 31, 2008 when the Company's stock price was $0.30 per share. The warrants have a strike price of $0.50 per share and are scheduled to expire October 31, 2012. Using the Black-Scholes model, the warrants were valued at $375,000.

The Company issued 100,000 warrants to purchase 1 share of stock to a private lender in lieu of interest. The warrants were issued on June 11, 2008 and expire on June 30, 2012. The stock was trading at $0.50 at the time of issue and the strike price is also $0.50 per share. Using the Black-Scholes model, the warrants were valued at $36,967.

The Company issued 1,000,000 warrants to a consultant. The warrants were issued effective January 1, 2009 and are scheduled to expire December 31, 2019. The strike price of $0.30 per share is equal to the market price on the date of issue. Using the Black-Scholes model, the warrants were valued at $300,000.

(8) FAIR VALUE ESTIMATES

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements". The objective of SFAS 157 is to increase consistency and comparability in fair value measurements and to expand disclosures about fair value measurements. SFAS 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, and expands disclosures about fair value measurements. SFAS 157 applies under other accounting pronouncements that require or permit fair value measurements and does not require any new fair value measurements.

The Company measures it options and warrants at fair value in accordance with SFAS 157. SFAS 157 specifies a valuation hierarchy based on whether the inputs to those valuation techniques are observable or unobservable. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect the Company's own assumptions. These two types of inputs have created the following fair value hierarchy:

Level 1 - Quoted prices for identical instruments in active markets;

Level 2 - Quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active, and model-derived valuations in which all significant inputs and significant value drivers are observable in active markets; and

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Level 3 - Valuations derived from valuation techniques in which one or more significant inputs or significant value drivers are unobservable.

This hierarchy requires the Company to minimize the use of unobservable inputs and to use observable market data, if available, when estimating fair value. The fair value of the options and warrants and long-lived assets held for sale at March 31, 2009 was as follows:

Fair Value Measurements at Reporting Date Using

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Options and Warrants	$ -	$ 1,234,189	$ -	$ 1,234,189
Long-lived Assets Held For Sale	$ -	$ 150,000	$ -	$ 150,000

The provisions of SFAS 157 are effective for fair value measurements made in fiscal years beginning after November 15, 2007

Options and warrants were valued using the Black-Scholes model.

Certain east Texas leases were valued using an agreed upon sales price in connection with the pending sale of the leases.

(9) ASSET RETIRMENT OBLIGATION

The asset retirement obligation ("ARO") represents the estimated present value of the amount we will incur to plug and abandon our producing properties at the end of their productive lives, in accordance with applicable state laws.

We recorded the initial ARO during the fiscal year ended March 31, 2009. We calculated the present value of the ARO by applying an annual inflation factor of 3% to the current cost to plug and abandon our producing properties in order to estimate the future cost to plug and abandon the properties. We discounted the future costs to present values using a discount rate of 12.5% (the credit adjusted risk free rate). The carrying cost of the property was increased by the present value of the ARO and a liability was recorded. At March 31, 2009, our liability for ARO was $344 thousand, all of which was classified as non-current. Our asset retirement obligations are recorded as current or non-current liabilities based on the estimated timing of the related cash flows.

(10) ABANDONED LEASEHOLD

In 2005, The Company's predecessors acquired certain non-producing leasehold in the Fayetteville Shale. The leases had 5 year terms and will begin to expire during the fiscal year ending March 31, 2011. During the year ended March 31, 2008, the Company's management concluded that the acreage no longer fit with

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the rest of the Company's portfolio of oil and gas properties and decided to offer the acreage for sale. The Company received some initial indications of interest in the property, however, mid-way through the fiscal year, natural gas prices declined substantially. As of March 31, 2009, we had not received any offers on the property, and based upon the continuing low natural gas price and relatively short remaining term of the leases, management concluded that an impairment should be recorded and that the appropriate fair value of the leases was zero. Therefore, the Fayetteville acreage was fully impaired. The acreage was acquired with non-recourse financing. The financing agreements provide for repayment of the money loaned to acquire the property only as the property was drilled or out of the proceeds of a sale. Since we no longer plan to drill the property and there appears to be no market for the leasehold, the full amount of the liabilities related to the acquisition of the Fayetteville acreage and all accrued interest was offset against the cost. A net abandonment loss of $424,000 was recorded related to the impairment of the Fayetteville Shale leasehold.

(11) COMMITMENTS AND CONTINGENCIES

Office Lease
We signed a long-term sublease agreement in February, 2007. The sublease began in late June, 2007. The terms of the lease provide for a monthly base rent of $12,315. The base rent increased to $12,807 beginning July, 2008 and is scheduled to increase to $13,300 in July 2009. The minimum base rent until the lease expires on January 31, 2010 is $131,525.

Plugging
Some of the Corsicana oil and gas leases have been producing for more than one hundred years and there are approximately one hundred abandoned wells scattered throughout the leases. In order for the surfactant-polymer flood to be successful, we will need to cement in the old wells. Since the wells are relatively shallow, we are able to completely plug each well for less than $1,500. We consider these plugging costs to be costs of developing the surfactant-polymer flood. Successful efforts accounting requires that such development costs be capitalized, consequently, the plugging costs are capitalized as part of the project. Because these costs are related to the planned development of the polymer flood, rather than a retirement of an asset, management has not included the cost of plugging these old well bores in the asset retirement obligation. No contingency has been recorded for these development costs.

Legal Proceedings
On September 15, 2008, a royalty owner in the Corsicana polymer pilot, representing approximately one-third of the mineral ownership, filed an amendment to a suit originally filed in 2007. The amendment was filed to include the Company as a defendant. The suit alleges the lease has expired because no oil was produced from January 2005 through September 2005. The plaintiff has asked to declare the lease to be void; demands payment for any oil produced and sold subsequent to the time the lease expired; demands that all equipment and salvage located on the lease be given to the plaintiff; and asks that any plugging liability be adjudged to be the responsibility of the Company.

If the plaintiff should prevail in the lawsuit, the amount of the loss contingency cannot be reasonably estimated; therefore, no expense for this contingency has been recorded on the accompanying financial statements.

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(12) NOTE RECEIVABLE

ReoStar has a note receivable from our drilling contractor. The note is secured by the rig that was dedicated to our Barnett Shale acreage. The outstanding principal balance on March 31, 2009 and 2008 was $553,536 and $1,355,228, respectively.

(13) MAJOR CUSTOMERS

We market our production on a competitive basis. Gas produced in the Barnett is sold under a long-term contract scheduled to expire on May 31, 2017. Oil purchasers may be changed on 30 days notice. The price for oil is generally equal to a posted price set by major purchasers in the area or is based on NYMEX pricing, adjusted for quality and transportation. We sell to oil and gas purchasers on the basis of price, credit quality and service. For the years ended March 31, 2009 and 2008, three customers, Cimarron Gathering, LP; Copano Field Services, North Texas LLC; and Plains Marketing L.P. accounted for nearly 100% of total oil and gas sales. Since our products are commodities and since there are numerous purchasers that service our markets, we believe that the loss of any one customer would not have a material adverse effect on our results.

(14) CREDIT RISK

We frequently maintain a balance in our bank accounts in excess of the federally insured limits.

(15) DISCONTINUED OPERATIONS

Effective May 1, 2007, ReoStar sold its entire interest in the Tri-County Gas Gathering System.

The following summarizes the proceeds and gain from the sale of the Tri-County Gas Gathering System:

Total Proceeds	$	15,000,000
Closing adjustment for unpaid capital calls		(900,000)
Net Proceeds		14,100,000
Basis in the pipeline		(8,827,299)
Total Gain on sale		5,272,701
Less Allocations to Minority Interest		(3,040,693)
Less Income Tax on Gain		(781,203)
Net Gain on Sale of Pipeline	$	1,450,805

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The following summarizes the income and expenses of the Tri-County Gas Gathering System:

		Year Ended March 31, 2008
Pipeline Revenue	$	125,801
Pipeline Operating Expenses		(46,428)
Minority Interest Expense		(44,096)
Income Tax Expense		(12,347)
Net Income from Discontinued Operations	$	22,930

(16) SUBSEQUENT EVENTS

On May 22, 2009 the Company signed a purchase letter agreement with an unrelated third party whereby the Company agreed to sell all of its ownership interest in two east Texas leases for $150,000 cash. The sale is expected to close in late June 2009. In connection with the sale, the Company included an impairment expense of approximately $203,000 in depletion, depreciation, and amortization expense to write the cost basis in the asset down to the agreed upon sales price. These leases have been reclassed to Leasehold Held for Sale and approximate their market value at March 31, 2009.

On June 16, 2009, all 11,462,000 of the warrants issued in conjunction with the 2007 private placement offering expired.

(17) SUPPLEMENTAL INFO ON OIL AND GAS EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES (UNAUDITED).

The following information concerning our natural gas and oil operations has been provided pursuant to Statement of Financial Accounting Standards No. 69, "Disclosures about Oil and Gas Producing Activities," ("SFAS No. 69"). All of our natural gas and oil producing activities are located in Texas.

Capitalized Costs Relating to Oil and Gas Producing Activities

	Fiscal Year Ended March 31,			
		2009		2008
Unproved oil and gas properties	$	484,198	$	2,445,556
Proved oil and gas properties		23,920,960		14,456,967
Support Equipment and facilities		-		-
Capitalized Interest		999,620		930,408
Total Capitalized Cost of Oil and Gas Properties		25,404,778		17,832,931
Less accumulated depletion, depreciation, and amortization		(6,206,558)		(4,139,337)
Net Capitalized Costs	$	19,198,220	$	13,693,594

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Costs incurred in Oil and Gas Producing Activities

	Fiscal Year Ended March 31, 2009	2008
Property Acquisition Costs		
Proved	$ 427,676	$ 1,814,718
Unproved	15,472	271,151
Exploration Costs	267,212	4,933,277
Development Costs	7,393,929	696,594
Asset retirement costs recognized according to SFAS No. 143	344,079	-
Total Costs Incurred	$ 8,448,368	$ 7,715,740

Key Production Statistics:

The following reflects the oil and gas production for the fiscal years ended March 31, 2008 and 2009:

		Oil & Gas Production Oil (Bbl)	Gas (Mcf)	Total BOE
Fiscal Year Ended	3/31/2008	33,602	351,538	92,192
Fiscal Year Ended	3/31/2009	45,105	479,180	124,968

Results of Operations for Producing Activities:

The following reflects results of operations for the fiscal years ended March 31, 2009 and 2008:

	Fiscal Year Ended March 31, 2009	2008
Oil & Gas Revenue	$ 6,558,069	$ 4,902,072
Gain on Sale of Oil & Gas Leases	18,005	307,028
Production Costs	3,140,198	2,800,388
Exploration Costs	2,975	61,179
Expired Leases and Plugging Costs	433,969	290,959
Depreciation, Depletion, & Amortization	4,591,131	1,399,293
	(1,592,199)	657,281
Income Taxes	557,270	(230,048)
Results of operations for oil and gas producing activities (excluding corporate overhead and financing costs)	$ (1,034,929)	$ 427,233

Estimated Quantities of Proved Oil and Gas Reserves (Unaudited)

We engaged Forrest A. Garb & Associates, Inc. to conduct a reserve study and to estimate our reserves of crude oil, condensate, natural gas liquids and natural gas. Reserves are adjusted to reflect contractual arrangements and royalty rates in effect at the end of each year. Many assumptions and judgmental decisions are required to estimate reserves. Reported quantities are subject to future revisions, some of which may be substantial, as additional information becomes available from reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors.

The SEC defines proved reserves as those volumes of crude oil, condensate, natural gas liquids and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable from known reservoirs under existing economic and operating conditions. Proved developed reserves are those proved reserves which can be expected to be recovered from existing wells with existing equipment and operating methods. Proved undeveloped reserves are volumes expected to be recovered as a result of additional

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investments for drilling new wells to offset productive units, recompleting existing wells, and/or installing facilities to collect and transport production.

Changes in estimates of proved reserves significantly impact the depletion expense we record each year. When proved reserves increase, our depletion rate decreases, resulting in a lower depletion expense and higher net income. Conversely, when proved reserves decrease, our depletion rate increases, resulting in a higher depletion expense and lower net income. Changes in estimates of proved reserves are frequently the result of changes in commodity prices, changes in operating costs, and reservoir performance history.

Production quantities shown are net volumes sold. These may differ from volumes withdrawn from reservoirs due to inventory changes, and, especially in the case of natural gas, volumes consumed for fuel and/or shrinkage from extraction of natural gas liquids.

The reported value of proved reserves is not necessarily indicative of either fair market value or present value of future net cash flows because prices, costs and governmental policies do not remain static, appropriate discount rates may vary, and extensive judgment is required to estimate the timing of production. Other logical assumptions would likely have resulted in significantly different amounts.

The reports utilize the base crude oil and natural gas prices in effect at March 31, 2009 and 2008, respectively. For the reserves at March 31, 2009, the base crude oil and natural gas prices were $49.65 per barrel ("Bbl") and $3.58 per million British thermal units ("MMbtu"), respectively. For the reserves at March 31, 2008, the base crude oil and natural gas prices were $101.54 per bbl and $9.86 MMbtu, respectively. The base prices for both crude oil and natural gas are adjusted by the normal price differential between the prices we historically have received for our products and the spot price quoted on the relevant market exchange.

Our proved reserves (000's omitted) are summarized in the table below.

	Oil (MBBL)	Gas (MMCF)
Reserves at March 31, 2007	11,677	3,392
Correction of Error	(11,293)	-
Revisions of previous estimates	323	(133)
Improved recovery	124	4,786
Purchases of minerals in place	24	525
Extensions and discoveries	590	10,591
Production	(34)	(351)
Sales of minerals in place	-	-
Reserves at March 31, 2008	1,411	18,809
Revisions of previous estimates	(739)	(11,269)
Improved recovery	-	-
Purchases of minerals in place	1	25
Extensions and discoveries	397	4,725
Production	(45)	(479)
Sales of minerals in place	-	-
Reserves at March 31, 2009	1,025	11,811

Correction of Error: The table above identifies a correction of an error in a previous estimate of oil reserves for the year ended March 31, 2007. The reserve report classified 11,293 MBBLS of oil as proven undeveloped. These reserves do not meet the criteria to be classified as proven and should have been excluded from the March 31, 2007 report.

Revisions of previous estimates: The table also identifies downward revisions in both oil and gas reserves for the year ended March 31, 2009. The downward revision is primarily a function of price. The base oil price at March 31, 2009 was more than 51% lower than the base price included in the previous reserve report. The base natural gas price at March 31, 2009 was down by more than 60%. Consequently, as the properties experience their expected declines, the properties are expected to become non-economic earlier, resulting in significantly less projected economically recoverable reserves.

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Improved recovery: During the fiscal year ended March 31, 2008, the Company implemented changes to the completion techniques on its Barnett Shale properties that resulted in increased recoverable reserves. Consequently, estimates of recoverable reserves for properties shown as proved undeveloped reserves on the March 31, 2007 were increased to reflect the increase in estimated reserves from the new techniques.

Purchases of minerals in place: The Company began a working interest repurchase program in its Barnett Shale properties in December 2007. On December 4, 2007, the Company agreed to repurchase working interests in 27 wells and has subsequently from time to time, repurchased smaller working interests.

Extensions and discoveries: The Company successfully drilled 8 and 18 of the Barnett shale locations that were classified as proven undeveloped properties for the years ending March 31, 2009 and 2008, respectively. The successful drilling of the wells resulted in additional proven undeveloped reserves in offset locations.

The following table reflects total reserves by project at April 1, 2009:

	Barnett Shale Project			**Corsicana Project**	**East Texas Project**
	Crude Oil (MBBL)	Natural Gas (MMCF)	Crude Oil Equivalents (MBOE)	Crude Oil (MBBL)	Crude Oil Equivalents (MBOE)
Proved Developed Producing	94	2,812	563	100	11
Proved Developed Non-Producing	43	494	125	87	2
Proved Undeveloped	655	8,505	2,073	33	-
Total Proved Reserves at April 1, 2009	792	11,811	2,761	220	13

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Unaudited)

The following summarizes the policies we used in the preparation of the accompanying natural gas and oil reserve disclosures, standardized measures of discounted future net cash flows from proved natural gas and oil reserves and the reconciliations of standardized measures from year to year. The information disclosed, as prescribed by SFAS No. 69, is an attempt to present the information in a manner comparable with industry peers.

The information is based on estimates of proved reserves attributable to our interest in natural gas and oil properties as of April 1, 2009. These estimates were prepared by an independent petroleum engineering firm, Forest Garb and Associates, Inc. Proved reserves are estimated quantities of natural gas and crude oil which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows:

Estimates are made of quantities of proved reserves and future amounts expected to be produced based on current year-end economic conditions.

Estimated future cash inflows are calculated by applying current year-end prices of natural gas and oil relating to our proved reserves to the quantities of those reserves produced in each future year.

Future cash flows are reduced by estimated production costs, costs to develop and produce the proved reserves and abandonment costs, all based on current year-end economic conditions.

The resulting future net cash flows are discounted to present value by applying a discount rate of 10%.

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The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair value of our natural gas and oil reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs and a discount factor more representative of the time value of money and the risks inherent in the industry.

The standardized measure of discounted future net cash flows relating to proved natural gas and oil reserves as of March 31, 2009 and 2008 is as follows:

	As of March 31,			
In thousands		2009		2008
Future Cash Inflows	$	90,391	$	311,067
Future Production and Development Costs		(55,865)		(107,195)
Income Taxes		(12,084)		(71,355)
Future Net Cash Flows		22,442		132,517
10% Annual Discount		(12,120)		(64,216)
Standardized Measure of Discounted Future Net Cash Flow	$	10,322	$	68,301

The following reconciles the change in the standardized measure of discounted future net cash flow during the fiscal years ended March 31, 2009 and 2008:

	Year Ended March 31,			
In thousands		2009		2008
Balance at beginning of year	$	68,301	$	117,629
Correction of error		-		(451,003)
Net change in prices and production costs		(194,933)		19,348
Net changes in future development costs		6,807		(14,805)
Sales of oil & gas produced net of production costs		(3,533)		(2,458)
Extensions and discoveries		23,664		98,476
Previously estimated development costs incurred		8,243		2,188
Revisions of previous quantity estimates		(10,020)		78,631
Purchases of reserves		427		1,815
Net change in income taxes		59,271		93,733
Accretion of discount		52,095		124,747
End of Year	$	10,322	$	68,301

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The following shows the standardized measure of discounted future net cash flow by project as of March 31, 2009:

In thousands	Total April 1, 2009	Barnett Project April 1, 2009	Corsicana Project April 1, 2009	East Texas Project April 1, 2009
Future Cash Inflows	$ 90,391	$ 79,631	$ 10,095	$ 665
Future Production and Development Costs	(55,865)	(48,034)	(7,588)	(243)
Income Taxes	(12,084)	(11,059)	(878)	(147)
Future Net Cash Flows	22,442	20,538	1,629	275
10% Annual Discount	(12,120)	(11,366)	(668)	(86)
Standardized Measure of Discounted Future Net Cash Flow	$ 10,322	$ 9,172	$ 961	$ 189

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ITEM 9. CHANGE IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A(T). CONTROLS AND PROCEDURES

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures (as defined in 13a-15(e) of the Securities Exchange Act of 1934, or the Exchange Act). Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that our disclosure controls and procedures are effective.

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation, our management concluded that our internal control over financial reporting was effective as of March 31, 2009.

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

There have been no changes in our internal control over financial reporting identified in connection with the evaluation required by paragraph (d) of Rule 13a-15 or 15d-15 under the Exchange Act that occurred during the quarter ended March 31, 2009 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

Not Applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

The information required by this Item is incorporated by reference from the information under the captions entitled "Election of Directors-Nominees," "Executive Officers" and "Section 16(a) Beneficial Ownership Reporting Compliance" in our definitive proxy statement to be filed with the SEC within 120 days after the end of the fiscal year ended March 31, 2009.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference from the information under the caption entitled "Executive Officer Compensation and Other Information" in our definitive proxy statement to be filed with the SEC within 120 days after the end of the fiscal year ended March 31, 2009.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this Item is incorporated by reference from the information under the caption entitled "Security Ownership of Certain Beneficial Owners and Management" in our definitive proxy statement to be filed with the SEC within 120 days after the end of the fiscal year ended March 31, 2009

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The information required by this Item is incorporated by reference from the information under the caption entitled "Certain Transactions" in our definitive proxy statement to be filed with the SEC within 120 days after the end of the fiscal year ended March 31, 2009.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this Item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of the fiscal year ended March 31, 2009.

ITEM 15. EXHIBITS INDEX

(a) Financial statements

Reference is made to the Index and Financial Statements under Item 8 in Part II hereof where these documents are listed.

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(b) Financial statement schedules

Financial statement schedules are either not required or the required information is included in the consolidated financial statements or notes thereto filed under Item 8 in Part II hereof.

(c) Exhibits

The exhibits to this Annual Report on Form 10-K are set forth below.

Number	Exhibit Description
3(i).1	Articles of Incorporation filed with the Nevada Secretary of State on November 29, 2004. (Incorporated by reference from the registrant's registration statement on Form SB-2 filed on September 8, 2005.)
3(i).2	Certificate of Change filed with the Nevada Secretary of State on November 21, 2006. (Incorporated by reference from the registrant's registration statement on Form 8-K filed on November 30, 2006.)
3(i).3	Certificate of Amendment filed with the Nevada Secretary of State on February 7, 2007. (Incorporated by reference from the registrant's registration statement on Form SB-2 filed on August 1, 2007.)
3(ii).1	Bylaws. (Incorporated by reference from the registrant's registration statement on Form SB-2 filed on August 1, 2007.)
10.1	Purchase and Sale Agreement by and between the registrant and United Texas Petroleum, Inc. dated December 4, 2007. (Incorporated by reference from the registrant's current report on Form 8-K filed on December 7, 2007.)
10.2	Contribution Agreement by and among the registrant, JMT Resources, Ltd., REO Energy, Ltd., and Benco Operating, Inc. dated February 1, 2007. (Incorporated by reference from the registrant's current report on Form 8-K filed on February 6, 2007.)
10.3	Private Placement Subscription Agreement. (Incorporated by reference from the registrant's registration statement on Form SB-2 filed on August 1, 2007.)
10.4	Common Stock Purchase Warrant. (Incorporated by reference from the registrant's registration statement on Form SB-2 filed on August 1, 2007.)
10.5	Joint Operating Agreement dated February 1, 2007 by Rife Energy Operating, Inc. and the registrant. (Incorporated by reference from the registrant's registration statement on Form SB-2 filed on August 1, 2007.)
10.6	Joint Operating Agreement by and between the registrant and Texas MOR, Inc. dated February 1, 2007. (Incorporated by reference from the registrant's registration statement on Form SB-2 filed on August 1, 2007.)
10.7	Employee Confidentiality and Property Agreement by and between the registrant and Scott Allen. (Incorporated by reference from the registrant's registration statement on Form SB-2 filed on August 1, 2007.)

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10.8	Employee Confidentiality and Property Agreement by and between the registrant and Mark S. Zouvas. (Incorporated by reference from the registrant's registration statement on Form SB-2 filed on August 1, 2007.)
10.9	Employee Confidentiality and Property Agreement by and between the registrant and Brett Bennett. (Incorporated by reference from the registrant's registration statement on Form SB-2 filed on August 1, 2007.)
10.10	Purchase and Sale Agreement by and between Cimmarron Gathering, LP. and the registrant dated June 6, 2007. (Incorporated by reference from the registrant's current report on Form 8-K filed on June 7, 2007.)
10.11	Purchase and Sale Agreement by and between the registrant and Vern Wilson Energy, Inc. dated September 28, 2007. (Incorporated by reference from the registrant's current report on Form 8-K filed on October 4, 2007.)
10.12	Purchase and Sale Agreement by and between the registrant and United Texas Petroleum, Inc. dated December 4, 2007. (Incorporated by reference from the registrant's Form 8-K filed on December 7, 2007.)
21.1	List of Subsidiaries of the Registrant. (Incorporated by reference from the registrant's Form 10-K filed on July 14, 2009).
23.1	Consent of Forest Garb & Associates.
31.1	Certification by the CEO Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification by the CFO Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification by the CEO Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification by the CFO Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Exchange Act, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

REOSTAR ENERGY CORPORATION

Date: April 9, 2010

By: /s/ Mark S. Zouvas
Mark S. Zouvas
President, Chief Executive Officer and Director

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Mark S. Zouvas and Scott Allen, jointly and severally, his attorney-in-fact, with the power of substitution, for him in any and all capacities, to sign any amendments to this annual report on Form 10-K and to file the same, with exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, hereby ratifying and confirming all that each of said attorneys-in-fact, or his substitute or substitutes, may do or cause to be done by virtue hereof.

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

SIGNATURE	TITLE	DATE
/s/ Mark S. Zouvas Mark S. Zouvas	President, Chief Executive Officer and Director (Principal Executive Officer)	April 9, 2010
/s/ Scott Allen Scott Allen	Chief Financial Officer and Director July 14, 2008 (Principal Financial Officer)	April 9, 2010
/s/ M. O. Rife III M. O. Rife III	Chairman of the Board of Directors	April 9, 2010
/s/ Jean-Baptiste Heinzer Jean-Baptiste Heinzer	Director	April 9, 2010
/s/ Alan Rae Alan Rae	Director	April 9, 2010