GEOPETRO RESOURCES CO
Form 10-K
April 02, 2007

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

Form 10-K

ANNUAL REPORT

PURSUANT TO SECTION 13 OR 15(d)

OF THE SECURITIES EXCHANGE ACT OF 1934

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

For the fiscal year ended December 31, 2006

OR

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

For the transition period from to

Commission File Number 001-16749

GeoPetro Resources Company

(Exact name of registrant as specified in its charter)

California	**94-3214487**
(State of incorporation)	(IRS Employer Identification Number)
One Maritime Plaza, Suite 700 **San Francisco, CA**	**94111**
(Address of principal executive offices)	(Zip Code)

(415) 398-8186

(Registrant s telephone number, including area code)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, No Par Value	American Stock Exchange

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

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 Section 15(d) of the Act. Yes o No x

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

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

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

Large accelerated filer o	Accelerated filer o	Non-accelerated filer x

Indicate by check mark whether the registrant is a shell company. Yes o No x

The aggregate market value of the registrant s common stock held by non-affiliates was approximately $124,733,634 based on the closing sale price of $4.95 per share as reported by the American Stock Exchange on March 28, 2007.

The number of shares of the registrant s common stock outstanding on March 30, 2007 was 29,359,718.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant s Proxy Statement relating to the 2007 Annual Meeting of Shareholders to be filed on or before April 30, 2007 are incorporated by reference into Part III of this Form 10-K.

GEOPETRO RESOURCES COMPANY

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Forward-Looking Statements

This Annual Report on Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act and we intend that such forward-looking statements be subject to the safe harbors created thereby. These statements are related to future events or our future financial performance. We have attempted to identify forward-looking statements with terminology, including anticipate, believe, can, continue, could, estimate, expect, intend, may, plan, will, or similar expressions as they relate to us and our business, industry and markets. All statements other than statements of historical fact are statements that could be deemed forward-looking statements, such as those statements that address activities, events or developments that we expect, believe or anticipate will or may occur in the future. These statements are based on certain assumptions and analyses made by us in light of our experience and perception of historical trends, current conditions, expected future developments and other factors we believe are appropriate in the circumstances. Such forward looking statements are subject to change based on factors beyond our control. Certain factors that may affect our financial condition and results of operations are discussed in Item 1A Risk Factors and Item 7A Quantitative and Qualitative Disclosures About Market Risk of this Annual Report on Form 10-K, and may be discussed from time to time in our reports filed with the Securities and Exchange Commission subsequent to this report. We assume no obligation, nor do we intend, to update these forward-looking statements, unless required by law. Unless the context requires otherwise, references in this Annual Report on Form 10-K to GeoPetro, we, us and our refer to GeoPetro Resources Company and its consolidated subsidiaries.

PART I

Item 1. *Business*

We were incorporated in the State of Wyoming in August 1994 under the name GeoPetro Company as an oil and gas exploration, development drilling and production company. In June 1996, we merged with our wholly-owned subsidiary, GeoPetro Resources Subsidiary Company, a California corporation, and the resulting merged company is incorporated in the state of California under the California General Corporation Law under the name GeoPetro Resources Company.

Our principal and registered office is located at One Maritime Plaza, Suite 700, San Francisco, California, USA 94111.

Intercorporate Relationships

We hold 100% of the shares of Redwood Energy Company, a Texas corporation, **Redwood.** Redwood is the general partner of, and holds a 5% interest in, Redwood Energy Production, L.P., **Redwood LP** , a Texas limited partnership. We are the sole limited partner of Redwood LP and own the remaining 95% partnership interest in Redwood LP.

In addition, we hold a 12% interest in Continental-GeoPetro (Bengara II) Ltd., **C-G Bengara** which is a British Virgin Islands company and a 50% interest in CG Xploration Inc., **CG Xploration** , which is a Delaware corporation.

We also hold 100% of the shares of GeoPetro Canada Ltd., **GeoPetro Canada** , an Alberta company, and 100% of the shares of GeoPetro Alaska LLC **GeoPetro Alaska** , an Alaska limited liability company.

GENERAL DEVELOPMENT OF THE BUSINESS

During the past five years, we have conducted leasehold acquisition, exploration and drilling activities on our North American, Australian and Indonesian prospects. These projects currently encompass approximately 1.56 million gross (396,080 net) acres, consisting of mineral leases, production sharing contract and exploration permits that give us the right to explore for, develop and produce oil and natural gas. Most of these properties are in the exploration, appraisal or development drilling phase and have not begun to produce revenue from the sale of oil and natural gas. Excluding minor interest and dividend income, our only cash inflows until 2003 were the recovery of capital invested in projects through sale or other divestiture of interests in oil and gas prospects to industry partners.

In December 2000, we acquired working interests in oil and natural gas leases in the Madisonville Field in Madison County, Texas, including interests in the Rodessa Formation. Also included in the acquisition was the Magness Well, an existing well that had been drilled, cased and production tested in the Rodessa Formation. In October 2001, we re-completed and tested the Magness Well over a 12-day period. In October 2002, we drilled, completed and successfully tested an injection well to dispose of waste products resulting from the treating process for gas produced from the Rodessa Formation. The Madisonville Field gas treatment plant and associated pipelines, which were built specifically for this project, were placed into service in May 2003, and the Magness Well began production in late May 2003. Since 2003, substantially all of our revenue has been generated from natural gas sales derived from the Madisonville Field. Gas sales from the Madisonville Field accounted for approximately 99% of our consolidated revenue during the year ended December 31, 2006. The Madisonville Project is expected to be our primary source of revenue in 2007. The first development well in the Madisonville Field, the Fannin Well, was drilled in 2004 and was tested at rates of up to 25.7 MMcf/d. In 2006, we drilled the Wilson and Mitchell wells. Presently, the Fannin and Magness wells are producing at a combined restricted rate of approximately 16.5 MMcf/d while the Wilson and Mitchell wells are shut-in awaiting a planned expansion of the gas treatment plant. We own a 100% working interest in the four wells. Historically, our wells have been production constrained by the gas treatment plant at the Madisonville Field, which presently has a designed treating capacity limit of approximately 18,000 Mcf per day. We have entered into an agreement with the plant owner, MGP, an unaffiliated third party, which provides, among other things, that MGP will expand the treating capacity of the plant from 18,000 to 68,000 Mcf per day to treat additional volumes from our producing wells. We expect the expanded capacity of the treatment plant to be available in the second quarter of 2007; however, there is no guarantee that the expansion will be completed within that time period. We expect the majority of our capital expenditures in 2007 to be the costs of drilling and completing wells in the Madisonville Field.

As of March 30, 2007 we have 29,359,718 shares of common stock outstanding as a result of raising approximately $46 million of equity, net of offering costs, by way of private placements and a public offering in Canada. These funds have been used primarily to acquire, explore and develop our oil and natural gas prospects.

Our common stock commenced trading under the symbol GPR on the American Stock Exchange on February 15, 2007. Our common stock is also listed on the Toronto Stock Exchange under the symbol GEP.S.

On March 30, 2006, we completed an initial public offering in Canada, which consisted of 3,730,021 shares of common stock at an issue price of $3.50 per share and 519,500 shares of common stock issued on a flow-through basis under the *Income Tax Act* (Canada) at an issue price of $3.85 per share for aggregate gross proceeds of $15,055,149. We have used the net proceeds of the offering primarily to fund development drilling of proven and probable natural gas reserves associated with the Madisonville Project.

Growth Strategy

Our strategy is to maximize shareholder value through the exploration and development drilling of oil and natural gas prospects. To carry out this philosophy we employ the following business strategies:

- identify and pursue potential projects which individually have the potential to be company makers which we define as projects which could generate a minimum unrisked net present value of $50 million net to our interest using a 10% discount factor;

- perform geological, engineering and geophysical evaluations;

- gain control of key acreage;

- generate high quality drillable exploration and development drilling prospects;

- retain a large working interest in those projects which involve low risk appraisal or development drilling, exploitation or appraisal of proven, probable and possible reserves; and

- minimize early investment and exploration risk in higher risk exploratory prospects through farmouts to other oil and natural gas companies and maintain meaningful interests with a carry through the exploration phase.

Risks Associated With Foreign Operations

Our business activities in Indonesia, Australia, Canada and the United States are subject to political and economic risks, including: loss of revenue, property and equipment as a result of unforeseen events like expropriation, nationalization, war, terrorist attacks and insurrection; risks of increases in import, export and transportation regulations and tariffs, taxes and governmental royalties; renegotiation of contracts with governmental entities; changes in laws and policies governing operations of foreign-based companies in Indonesia; exchange controls, and numerous other factors. While we expect these risks are greater in Indonesia, especially political risk, any one or more of such political or economic conditions could change in the United States, Canada or Australia to our detriment. For a related discussion of the risks attendant with foreign operations, see Risk Factors.

Financial Information About Geographic Areas

Please see the notes to the financial statements for information concerning oil and gas properties located in the United States and foreign countries.

Regulations

Domestic exploration for, and production and sale of, oil and gas are extensively regulated at both the federal and state levels. Our business is and will be directly or indirectly affected by numerous governmental laws and regulations applicable to the energy industry, including:

- Federal environmental laws and regulations
- State environmental laws and regulations
- Local environmental laws and regulations
- Conservation laws and regulations
- Tax and other laws and regulations pertaining to the energy industry

Legislation, rules and regulations affecting the oil and gas industry are under constant review for amendment or expansion, frequently increasing the regulatory burden. Any changes in the existing legislation, rules or regulations could adversely affect our business. The regulatory burdens are often costly to comply with and carry substantial penalties for failure to comply.

As of March 30, 2007, we have re-completed an existing well and drilled three additional production wells and an injection well in the Madisonville Project as operator. In addition, we may drill oil, gas and disposal wells in the future as the operator and will be required to obtain local government and other permits to drill such wells. There can be no assurance that such permits will be available on a timely basis or at all. Texas and other states have statutes or regulations pertaining to conservation matters which, among other matters, regulate the unitization or pooling of gas properties and the spacing, plugging and abandonment of such wells and set limits on the maximum rates of natural gas that can be produced from gas wells.

Our operations and activities are subject to numerous federal, state and local environmental laws and regulations. These laws and regulations:

- Require the acquisition of permits
- Restrict the type, quantities and concentration of various substances that can be discharged into the environment

- Limit or prohibit drilling and other activities on wetlands and other designated, protected areas
- Regulate the generation, handling, storage, transportation, disposal and treatment of waste materials
- Impose criminal or civil liabilities for pollution resulting from oil and natural gas operations

We expect that with the increase in our exploratory and development drilling activities, the impact of environmental laws and regulations on our business and operations will also increase. We may be required in the future to make substantial outlays of money to comply with environmental laws and regulations. Additional changes in operating procedures and expenditures to comply with future environmental laws cannot be predicted.

Other than our U.S. projects, we do not operate oil and gas properties in which we own an interest. In those instances, we are not in the position to exert direct control over compliance with most of the rules and regulations discussed above. We are substantially dependent on the operators of our non-operated oil and gas properties to monitor, administer and oversee such compliance. The failure of the operator to comply with such rules and regulations could result in substantial liabilities to us.

As the operator of the Madisonville Project, among other various environmental laws and regulations, we will be subject to the U.S. Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) and any comparable legislation adopted by Texas which imposes strict, joint and several liability on owners and operators of properties and on persons who dispose or arrange for the disposal of hazardous substances found on or under the sites of such properties. Under CERCLA, one owner, lessee or other party, having responsibility for and an interest in a site requiring cleanup may, under certain circumstances, be required to bear a disproportionate share of liability for the cost of such cleanup if payments cannot be obtained from other responsible parties. The Resource Conservation and Recovery Act (RCRA) and comparable rules adopted by Texas and other states regulate the generation, management and disposal of hazardous oil and gas waste.

The Texas Railroad Commission has been delegated the responsibility and authority to regulate and prevent pollution from oil and gas operations, including the prevention of pollution of surface or subsurface water resulting from the drilling of oil and gas wells and the production of oil and gas. In addition to regulating the generation, management and disposal of hazardous oil and gas waste, the Texas Railroad Commission has been delegated authority to regulate underground hydrocarbon storage, saltwater disposal pits and injection wells.

The drilling of oil and gas wells in Texas requires operators to obtain drilling permits, file an organization report and a performance bond or other form of financial security, such as a letter of credit, and obtain a permit to maintain pits to store and dispose of drilling fluids, saltwater and waste as well as other types of pits for other purposes. The issuance of such permits is conditioned upon the Texas Railroad Commission s determination that these pits will not result in waste or pollution of surface or subsurface water.

Other states in which we have an interest in oil and gas properties may impose similar or more stringent regulations than imposed under CERCLA or RCRA.

In re-completing the existing well on the Madisonville Project, we were required to drill a well for injection or disposal of produced waste gas from wells. Injection wells are subject to regulation under the Safe Drinking Water Act (SDWA) and the regulations and procedures which have been adopted by the Environmental Protection Agency (EPA) under that Act. Generally, enforcement procedures under the SDWA are administered by the EPA unless such authority has been delegated by the EPA to a state which has primary enforcement responsibility based on the EPA s determination that the state has adopted drinking water regulations no less stringent than the national primary drinking water regulations and meets certain other criteria. Underground injection wells not used for the underground injection of natural gas for storage are generally unlawful and subject to penalties under the SWDA unless authorized by:

- permit issued by the EPA or a state having primary enforcement responsibility, or
- rule pursuant to an underground injection control program established by a state or the EPA.

The regulatory burden on the natural gas and oil industry increases our cost of doing business and affects our financial condition. Future developments, such as stricter requirements of environmental or health and safety laws and regulations affecting our business or more stringent interpretations of, or enforcement policies with respect to, such laws and regulations, could adversely affect us. To meet changing permitting and operational standards, we may be required, over time, to make site or operational modifications at our facilities, some of which might be significant and could involve substantial expenditures. There can be no assurance that material costs or liabilities will not arise from these or additional environmental matters that may be discovered or otherwise may arise from future requirements of law.

Overseas Regulations

We own working interests in oil and gas prospects located in Australia and Indonesia. We have farmed out our interest in some of these prospects to third parties, and other parties are operators of these properties. In exploring for, drilling and developing such properties, these operators will be required to comply with the environmental, conservation, tax and other laws and regulations of Australia and Indonesia. The Native Title Act of 1993, an Australian law, may affect our ability to gain access to prospective exploration areas or obtain production title on our Australian properties. In addition, if Native Title claims are filed in the future, we may be required to make payments to settle such claims. To date we have farmed out our interest in 20 properties since our inception. This has impacted our business from a financial point of view. In some instances, we have received cash consideration pursuant to the terms of a farmout which we typically record as a reduction of capitalized oil and gas properties. Often, the terms of the farmouts we negotiate require the third party farmee to expend a certain amount toward the exploration and/or development drilling of the property in order to earn an interest in the property. This lessens the demand on our own capital resources to perform the exploration and/or development drilling of the property. Conversely, when and if the property produces revenue, it also reduces our share of such revenue to the extent of the interest farmed out.

Technology

We participate in projects utilizing economically feasible exploration technology in our exploration and development drilling activities to reduce risks, lower costs, and more efficiently produce oil and gas. We believe that the availability of cost effective 2-D and 3-D seismic data makes its use in exploration and development drilling activities attractive from a risk management perspective in certain areas.

Briefly, through the use of a seismograph, a seismic survey sends pulses of sound from the surface down into the earth, and records the echoes reflected back to the surface. By calculating the speed at which sound travels through the various layers of rock, it is possible to estimate the depth to the reflecting surface. It then becomes possible to infer the structure of rock deep below the earth s surface. We evaluate substantially all of our exploratory prospects using 2-D seismic data. In addition, we own approximately 12 square miles of 3-D seismic data covering our leasehold and adjacent lands in the Madisonville Project.

The use of seismic technology does not entirely remove the risk of exploration and development drilling of oil and natural gas deposits. It is important to consider the following:

- we may not recognize significant geological features due to errors in interpretation, processing limitations, the presence of certain geological environments that are out of our control or other factors; and
- seismic generally becomes less reliable with increasing depth of the geological horizon; and
- the use of this technology may increase our finding cost over that if it is not used.

Principal Products

Our principal products are the production of natural gas and crude oil from properties in which we own an interest. Since our inception, we have realized only limited production of natural gas and crude oil from the properties in which we own an interest. We have working interests in various undeveloped oil and gas properties. See Properties for a general description of these properties.

During the last three fiscal years, 100% of our revenues have been derived from the sale of natural gas. Substantially all of our natural gas sales, approximately 99%, have been generated by two producing wells, the Magness #1 and Fannin #1 wells, located in the Madisonville Field in East Texas. Natural gas produced by the Magness #1 well is sold at the wellhead where it is delivered to a gathering pipeline and transported to a nearby gas treatment plant where it is treated to remove impurities. The gas is then transported nine miles to one of two common carrier pipelines from which point it is delivered to the greater Dallas, Texas area. The price received for the natural gas is the Houston Ship Channel price index less certain adjustments for the quality of the gas delivered. The adjustments for the quality of gas delivered at the wellsite as well as the gathering and transportation costs presently amount to approximately $1.70 per Mcf of untreated gas delivered at the wellsite.

For financial information regarding our business activities by segment, please see our Financial Statements beginning on page F-1 of this report. Substantially all of our revenue is produced from natural gas sales in the Madisonville Field located in East Texas.

Reserves

The volume of production from oil and natural gas properties generally declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our proved reserves will decline as reserves are produced from our properties unless we are able to acquire or develop new reserves.

Acquisition of Producing Properties

We may supplement our exploration efforts with acquisitions of producing oil and gas properties. We may seek to acquire producing properties that are underperforming relative to their potential.

Patents, Trademarks, Licenses, Franchises and Concessions Held

Permits and licenses are important to our operations, since they allow the search for the extraction of any oil, gas and minerals discovered on the areas covered. See Properties for a general description of the permits and licenses under which we operate. Provided we establish a commercial discovery thereon, the Bengara PSC in Indonesia grants us the right to produce oil and gas from the PSC area until 2027. In the event of commercial discovery and resulting production, our permits in Australia grant us the right to produce oil and gas from the permit areas until 2032.

Renegotiation of Profits or Termination of Contracts

Our property in Indosnesia is subject to the terms of a production sharing contract known as the Bengara II PSC. The Bengara II PSC is a standard terms production sharing contract employed by BP Migas, the applicable governing authority, for all oil and natural gas concessions in Indonesia. The Bengara II PSC provides for early termination and relinquishments of the contract area under certain conditions. These provisions are discussed in Properties *Indonesia - Terms of Participation in the Bengara Block.* See also Risk Factors.

Seasonality of Business

Our business is not seasonal.

Working Capital Items

The majority of our current assets are in the form of cash and deposits in trust received from the sale of natural gas from our Madisonville Project in Texas and from the sale of common stock in private placements. We are required to use this cash to pay for the cost of our operations and activities. See further, Management s Discussion and Analysis of Financial Condition and Results of Operations.

Customers

Substantially all of our revenues to date have been derived from sales by MGP to two customers, Atmos Pipeline-Texas, and ETC Katy Pipeline, Ltd., of natural gas produced from our Madisonville Project in Texas. We have not committed any forward sales of our natural gas. We contract to sell the gas with spot-market based contracts that vary with market forces on a monthly basis. No other customer accounts for in excess of 10% of our revenues.

Competition

The natural gas and oil industry is intensely competitive and speculative in all of its phases. We encounter competition from other natural gas and oil companies in all areas of our operations. In seeking suitable natural gas and oil properties for acquisition, we compete with other companies operating in our areas of interest, including large natural gas and oil companies and other independent operators, which have greater financial resources and in many instances, have been engaged in the exploration and production business for a much longer time than we have. Many of our competitors also have substantially larger operating staffs than we do. Many of these competitors not only explore for and produce natural gas and oil but also market natural gas and oil and other products on a regional, national or worldwide basis. These competitors may be able to pay more for productive natural gas and oil properties and exploratory prospects and define, evaluate, bid for and purchase a greater number of properties and prospects than us. In addition, these competitors may have a greater ability to continue exploration activities during periods of low market prices. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment.

The prices of our natural gas production are controlled by market forces. However, competition in the natural gas and oil exploration industry also exists in the form of competition to acquire leases and obtain favorable transportation prices. We are relatively small and may have difficulty acquiring additional acreage and/or projects and may have difficulty arranging for the transportation of our production. We also face competition in obtaining natural gas and oil drilling rigs and in sourcing the manpower to run them and provide related services.

Employees

Currently, we have 10 employees, all of whom are full time. We are not a party to any collective bargaining agreements and we have not experienced any strikes or work stoppages. We consider our relations with our employees to be good. We use the services of independent consultants and contractors to perform various professional services, including reservoir engineering, land, legal, environmental and tax services. On those properties where we are not the operator, we rely on outside operators to drill, produce and market our natural gas and oil.

Item 1A. ***Risk Factors***

In addition to risks and uncertainties in the ordinary course of business that are common to all businesses, important factors that are specific to our industry and our company could materially impact our future performance and results of operations. We have provided below a list of these risk factors that should be reviewed when considering our securities. These are not all the risks we face and other factors currently considered immaterial or unknown to us may impact our future operations.

Risks Related to Our Business

As of December 31, 2006 we have capitalized costs totaling $48.2 million as evaluated and unevaluated oil, and gas properties whereas we have generated revenues of only $22,970,070 since January 1, 2003.

Since inception, our activities have been primarily related to acquiring and exploring leasehold interests in oil and natural gas properties in Texas, California, Alaska, Alberta, Indonesia and Australia. We incur substantial acquisition and exploration costs and overhead expenses in our operations, and until 2003, excluding minor interest and dividend income, our only significant cash inflows were the recovery of capital invested in projects through sale or other divestitures of interests in oil and gas prospects to industry partners. As a result, we have sustained an accumulated deficit through December 31, 2006 of $10,393,985. Our production activities commenced in May 2003. Since May 2003, over 90% of our revenue has been generated from natural gas sales derived from the Magness #1 well in the Madisonville Field in Texas. It is possible that in the future we will be unable to continue to generate revenues from our sales of natural gas from the Magness #1 well because our proved reserves decline as reserves are produced from the Magness #1 well. The drilling of exploratory oil and natural gas wells is highly speculative and often unproductive. Our participation in future drilling activities to explore, develop and exploit the properties in which we have an interest, or in which we may acquire interests, may be unsuccessful, may fail to generate positive cash flow, and may not enable us to maintain profitability in the future.

Approximately 99% of our current revenues are generated by our interest in the Madisonville Project. Delays or interruptions of the Madisonville Project natural gas drilling and production operations including, but not limited to, events beyond our control or the failure of third parties on which we rely to provide key services, could negatively impact our revenues.

Approximately 99% of our oil and natural gas revenues for the year ended December 31, 2006 were derived from the Madisonville Project. In connection with that project, we have contracted with third parties to provide key services, including:

(a) Madisonville Gas Processing, LP (**MGP**), which owns and operates gathering pipelines and a dedicated natural gas treatment plant which we utilize to treat impurities in the Madisonville Project natural gas; and

(b) Gateway, which operates a sales pipeline for such natural gas.

The failure of MGP or Gateway to perform their contractual obligations to us could impose delays or interruptions in our production operations and prevent us from generating revenues. In addition, events which are beyond our control, or that of Gateway or MGP, could affect our production operations. Such events include, but are not limited to:

- events referred to as force majeure, such as an act of God, act of a public enemy, war, blockade, public riot, lightning, fire, storm, flood, explosion and any other causes whether of the kind enumerated or otherwise not reasonably within the control of MGP, Gateway or our company.

- subsurface conditions or formations encountered during the drilling of wells, whether natural or mechanical, including but not limited to blowout, igneous rock, salt, saltwater flow, loss of circulation, loss of hole, abnormal pressures, or any other impenetrable substance or adverse condition, which renders further drilling of a well impossible or impractical.

- the inability to secure raw materials or equipment,

- transportation accidents, and

- labor disputes and equipment failures.

In excess of 90% of our revenues to date have been derived from sales by MGP to two customers. The loss of one or both of these customers could have a material adverse impact on our oil and gas revenues.

Approximately 99% of our oil and natural gas revenues for the year ended December 31, 2006 were derived from the Madisonville Project. During 2005, all of these revenues were derived from the sale of gas by MGP and Hanover Compression Limited Partnership (**Hanover**) to one customer, Atmos Pipeline-Texas. During 2006 and the current year, approximately 99% of our revenues to date have been derived from sales by MGP to two customers, Atmos Pipeline-Texas, and ETC Katy Pipeline, Ltd. The loss of one of these customers could impact the price we receive for our gas sold due to lessened competition. The loss of both customers could result in a total loss of our revenue.

Unless we replace our oil and natural gas reserves, our reserves and production will decline.

The volume of production from oil and natural gas properties generally declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our proved reserves will decline as reserves are produced from our properties unless we are able to acquire or develop new reserves. The business of exploring for, developing or acquiring reserves is capital intensive. For example, as of December 31, 2006 we have capitalized costs totaling $48.2 million as evaluated and unevaluated oil and gas properties. To the extent cash flow from operations is reduced and external sources of capital become limited or unavailable, our ability to make the necessary capital investment to maintain or expand our asset base of oil and natural gas reserves will be impaired. Even if we are able to raise capital to develop or acquire additional properties, no assurance can be given that our future exploitation and development drilling activities will result in the discovery of any reserves.

Our exploration and development drilling activities may not be commercially successful. The drilling of exploratory oil and natural gas wells is expensive, highly speculative and often unproductive.

Exploration for oil and natural gas on unproven prospects is expensive, highly speculative and involves a high degree of risk, including the risk that no commercially productive oil or natural gas reservoirs will be encountered. Reserves are dependent on our ability to successfully complete drilling activity on proven prospects.

The cost of drilling, completing and operating wells is often uncertain, and drilling operations may be curtailed, delayed or cancelled as a result of a variety of factors, including:

- unexpected drilling conditions, pressure or irregularities in formations;
- equipment failures or accidents, adverse weather conditions;
- compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs and the delivery of equipment.

Our evaluations of the oil and gas prospects of our properties may be wrong.

With the exception of the Madisonville Project, the properties in which we have an interest are prospects in which the presence of oil and natural gas reserves in commercial quantities has not been established. Any decision to engage in exploratory drilling or other activities on any of these properties will be dependent in part on the evaluation of data compiled by petroleum engineers and geologists and obtained through geophysical testing and geological analysis.

Reservoir engineering, geophysics and geology are not exact sciences and the results of studies and tests used to make such evaluations are sometimes inconclusive or subject to varying interpretations. As such, there is no certain way to know in advance whether any of our prospects will yield oil and natural gas in commercial quantities. Further, it is possible that we will participate in the drilling of more dry holes than productive wells or that all or substantially all of the wells drilled will be dry holes. The drilling of dry holes on prospects in which we have an interest could adversely affect their values and our decision to undertake further exploration and development drilling of such prospects. It is not certain or predictable whether, and no assurance can be made that, the wells drilled on the properties in which we have an interest will be productive or, if productive, that we will recover all or any part of our investment in the properties. In sum, our participation in future drilling activities may not be successful and, if unsuccessful, such failure will negatively impact our revenues and have a material adverse effect on our results of operations and financial condition. Our oil and natural gas revenues were $6,716,360 million for the year ended December 31, 2006. Future revenues could decline from those levels if our future drilling efforts are not successful. Furthermore, as of December 31, 2006 we have capitalized costs totaling $48.2 million as evaluated and unevaluated oil and gas properties. Should our future drilling activities be unsuccessful, we may then be required to record an impairment charge equal to a portion of, or all, of the capitalized costs resulting in an immediate adverse impact on our results of operations and financial position.

Our business may be harmed by failures of third party operators on which we rely.

Our ability to manage and mitigate the various risks associated with certain of our exploration and operations in Alberta, Canada, Indonesia and Australia is limited since we rely on third parties to operate our projects. We are a non-operating interest owner in our Canadian, Indonesian and Australian properties. With respect to our interests outside of the United States, we have entered into joint operating agreements with third party operators for the conduct and supervision of drilling, completion and production operations. In the event that commercial quantities of oil and natural gas are discovered on one of our properties, the success of the oil and natural gas operations on that property depends in large measure on whether the operator of the property properly performs its obligations. The failure of such operators and their contractors to perform their services in a proper manner could result in materially adverse consequences to the owners of interests in that particular property, including us.

Our percentage share of oil and gas revenues from our Indonesian property is diminished by the terms of our production sharing contract in the Bengara Block.

On September 29, 2006, we sold 70% of our interest in C-G Bengara to CNPC (Hong Kong) Limited, thus reducing our interest in C-G Bengara from 40% to 12%. C-G Bengara is subject to a production sharing contract, which means generally that C-G Bengara is entitled to receive, from production proceeds, 100% of expenditures in the block as cost recovery. Once these costs are recovered, C-G Bengara s production share will be reduced to approximately 26.7% of oil produced and 62.5% of all natural gas produced. We are entitled to 12% of C-G Bengara s reduced share of any such production. See the discussion under Properties in this report for more information concerning the production sharing contract.

Drilling and completion equipment, services, supplies and personnel are scarce and may not be available when needed, which could significantly disrupt or delay our operations.

From time to time, there has been a general shortage of drilling rigs, equipment, supplies and oilfield services in North America, Australia and Indonesia, which may intensify with current increased industry activity. In addition, the costs and delivery times of rigs, equipment and supplies have risen. There can be no assurance that sufficient drilling and completion equipment, services and supplies will be available when needed. Shortages could delay our proposed exploration, development drilling, and sales activities, which could have a material adverse effect on our results of operations. Our oil and natural gas revenues were $6.7 million for the year ended December 31, 2006. Future revenues could decline from those levels if we experience delays in our proposed exploration, development drilling, and sales activities. The demand for, and wage rates of, qualified rig crews have risen in the drilling industry due to the increasing number of active rigs in service. If the demand for qualified rig crews continues to rise in the drilling industry, then the oil and gas industry may experience shortages of qualified personnel to operate drilling rigs. This could delay our drilling operations and adversely affect our financial condition and results of operations.

Our working interest in properties, and our ability to realize any profits from such properties, will be diminished to the extent that we enter into farmout arrangements with unaffiliated third parties.

We have previously entered into, and may in the future enter into, farmout arrangements with third parties willing to drill natural gas and oil wells on leaseholds in which we originally acquired working interests, in exchange for our assignment of part or all of our leasehold interests. As a consequence of these arrangements, our retained interests in properties which are subject to farmout arrangements have been or may be diminished. Our opportunity to realize revenues and profits from properties which are successfully developed under farmout arrangements will be diminished to the extent of our reduced interests.

We recently sold 70% of our working interest in the Bengara Block to an unaffiliated third party. The sale significantly diminished our interest and thus our ability to realize future profits in the Bengara Block.

Competition with other oil and natural gas exploration and development drilling companies for viable oil and natural gas properties may limit our success.

It is likely that in seeking future property acquisitions, we will compete with companies which have substantially greater financial and management resources. Our competition comes primarily from three sources:

(a) those competitors that are seeking oil and gas fields for expansion, further drilling, or increased production through improved engineering techniques;

(b) income-seeking entities purchasing a predictable stream of earnings based upon historic production from fields being acquired; and

(c) junior companies seeking exploration opportunities in unknown, unproven territories.

Our competitors may be able to pay more for productive oil and natural gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than we can. Our ability to acquire additional properties in the future will depend upon our ability to conduct efficient operations, evaluate and select suitable properties, implement advanced technologies and consummate transactions in a highly competitive environment.

Estimates of oil and natural gas reserves are inherently imprecise. Any material inaccuracies in these reserve estimates or underlying assumptions will affect materially the quantities and present value of our reserves.

Estimates of proved oil and natural gas reserves and the future net cash flows attributable to those reserves are prepared by independent petroleum engineers and geologists. There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and cash flows attributable to such reserves, including factors beyond our control and that of our engineers. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. Different reserve engineers may make different estimates of reserves and cash flows based on the same available data. The accuracy of an estimate of quantities of reserves, or of cash flows attributable to such reserves, is a function of the available data, assumptions regarding future oil and natural gas prices and expenditures for future development drilling and exploration activities, and of engineering and geological interpretation and judgment. Additionally, reserves and future cash flows may be subject to material downward or upward revisions, based upon production history, development drilling and exploration activities and prices of oil and natural gas. Actual future production, revenue, taxes, development drilling expenditures, operating expenses, underlying information, quantities of recoverable reserves and the value of cash flows from such reserves may vary significantly from the assumptions and underlying information set forth herein.

Competitive pressures may force us to implement new technologies at substantial cost and our limited financial resources may limit our ability to implement such technologies at the same rate as our competitors.

The oil and gas industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil and gas companies 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 do. There can be no assurance that we will be able to respond to such competitive pressures and implement such technologies on a timely basis or at all. One or more of the technologies currently utilized by us or implemented in the future may become obsolete.

We will require additional capital to fund our future activities. Our ability to pursue our business plan may be restricted by our access to additional financing.

Until such time as the properties in which we own interests are generating sufficient cash flow to fund planned capital expenditures, we will be required to raise additional capital through the issuance of additional securities or otherwise sell or farm out interests in our oil and natural gas properties to third parties. If and when the properties in which we own interests become productive and have adequate reserves, we may borrow funds to finance our future oil and natural gas operations and exploratory and development drilling activities. We may not be able to raise additional funds in the future from any source or, if such additional funds are made available to us, we may not be able to obtain such additional financing on terms acceptable to us. To the extent such funds are not available from any of those sources, our operations and activities will be limited to those operations and activities we can afford with the funds then available to us. We have committed to a three well drilling program in our Madisonville project to facilitate the expansion of the gas treatment plant. The commitment is not discretionary. While we have fulfilled the commitment to drill the first two wells of the three well commitment, we are further required to commence the drilling of a third well sufficient to test the Smackover Formation (estimated to be encountered at approximately 18,000 feet) on or before September 30, 2008. This well is expected to cost approximately $10 million to drill and complete. We have granted MGP a security interest in the Madisonville Field properties to secure the three well commitment. Subject to events of force majeure, and the availability of suitable drilling rigs, well services, and equipment, our failure to drill this well could result in the loss of our interest in the Madisonville Project. Our larger competitors, by reason of their size and relative financial strength, may be more easily able to access capital markets than us.

The volatility in crude oil and natural gas prices could adversely affect our financial results and ability to raise additional capital.

Our revenues, cash flows and profitability are substantially dependent on prevailing prices for both oil and natural gas. Decreases in natural gas prices will decrease revenues and cash flows from the Madisonville Project and our other producing properties, if any, and decreases in oil and natural gas prices could deter potential investors from investing in our company and generally impede our ability to raise additional financing to fund our exploration and development drilling activities. Historically, oil and natural gas prices and markets have been volatile, and they are likely to continue to be volatile in the future. Prices for oil and natural gas are subject to wide fluctuations in response to relatively minor changes in the supply of, and demand for, oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control. These factors include, but are not limited to, political conditions in the Middle East and other regions, internal and political decisions of OPEC and other oil and natural gas producing nations to decrease or increase production of crude oil, domestic and foreign supplies of oil and natural gas, consumer demand, weather conditions, domestic and foreign government regulations, transportation costs, the price and availability of alternative fuels and overall economic conditions.

Our current operations are particularly exposed to volatility in natural gas prices because a portion of the fees we pay to process natural gas at the Madisonville gas treatment plant is fixed. The sale price of natural gas must be above a minimum price of approximately $3.00 per Mcf at the present time before we earn any net revenues from the sale of natural gas.

We are subject to a number of operational risks beyond our control against which we may not have, or be able to obtain insurance.

Our operations are subject to the many risks and hazards incident to exploring and drilling for, and producing and transporting, oil and natural gas, including among other risks:

- blowouts, fires, craterings, pollution and equipment failures that may result in damage to or destruction of wells, producing formations, production facilities and equipment;

- personal injuries or death due to accidents, human error or acts of God;

- unavailability of materials and equipment to drill and complete or re-complete wells; unfavorable weather conditions; engineering and construction delays;

- fluctuations in product markets and prices; proximity and capacity of pipeline, and trucking or termination facilities to our oil and natural gas reserves; hazards resulting from unusual or unexpected geological or environmental conditions; environmental regulations and requirements;

- accidental leakage of toxic or hazardous materials, such as petroleum liquids or drilling fluids into the environment, remediation and clean-up costs; and

- political instability and civil unrest, insurrections or disruptions in foreign countries in which some of our interests are located.

If one or more of these events occurs, we could incur substantial liabilities to third parties or governmental entities, the payment of which could have a material adverse effect on our financial condition and results of operations, or we could lose properties in which we have invested significant sums (totaling $48.2 million) which are capitalized as evaluated and unevaluated oil and gas properties as of December 31, 2006.

A loss not covered by insurance could result in substantial expenses to us.

We do not insure fully against all business risks either because such insurance is not available or because premium costs are prohibitive. This is a common practice in the oil and gas industry. However, a loss not fully covered by insurance could result in expenses to us and could have a material adverse effect on our financial position and results of operations. Uninsured losses in excess of $1.0 million would be materially adverse.

We are subject to extensive government regulations that can change from time to time, compliance with which are costly and could negatively impact our production, operations and financial results.

The oil and gas industry is subject to extensive government regulations in the countries in which we operate. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, reports concerning operations, unitization and pooling of properties and taxation. Historically, our costs of complying with these regulations have not exceeded $100,000 per year. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and natural gas wells below actual production capacity in order to conserve supplies of oil and natural gas. We are also subject to changing and extensive tax laws, the effects of which cannot be predicted. Legal requirements are frequently changed and subject to interpretation, and we are unable to predict the ultimate cost of compliance with these requirements or their effects on our operations. Future laws, or existing laws or regulations, as currently interpreted or reinterpreted or changed in the future, could result in increased operating costs, fines and liabilities, in amounts which are unknown at this time, any of which could materially adversely affect our results of operations and financial condition.

Our industry is subject to extensive environmental regulation that may limit our operations and negatively impact our production.

Extensive national, state, provincial and local environmental laws and regulations in the United States and foreign jurisdictions affect nearly all of our operations. These laws and regulations set various standards regulating certain aspects of health and environmental quality, provide for penalties and other liabilities for the violation of such standards and establish in certain circumstances obligations to remediate current and former facilities and locations where operations are or were conducted. In addition, special provisions may be appropriate or required in environmentally sensitive areas of operation.

Environmental legislation may require that we, among other things:

- acquire permits before commencing drilling;
- restrict spills, releases or emissions of various substances produced in association with our operations;
- limit or prohibit drilling activities on protected areas such as wetlands or wilderness areas;
- take reclamation measures to prevent pollution from former operations;
- take remedial measures to mitigate pollution from former operations, such as plugging abandoned wells and remediating contaminated soil and groundwater;
- take remedial measures with respect to property designated as a contaminated site.

The cost of any of these actions is presently unknown but is likely to be significant.

Compliance with existing or future environmental legislation is unknown but could be substantial.

Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require us to incur substantial costs to remedy such discharge. Under these laws and regulations, we could be liable for personal injury, clean-up costs and other environmental and property damages, as well as administrative, civil and criminal penalties. We could be required to cease production on properties if environmental damage occurs. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. Changes in, or enforcement of, environmental laws may result in a curtailment of our production activities, or a material increase in the costs of production, development drilling or exploration, any of which could have a material adverse effect on our financial condition and results of operations or prospects. We are not presently aware of any environmental liabilities or able to predict the ultimate cost of liabilities not yet recognized. We have recorded an asset retirement obligation in connection with the estimated future costs to plug certain wells in our Madisonville Project in Texas upon abandonment totaling approximately $48,842 as of December 31, 2006.

Our Australian operations are subject to unique risks relating to Aboriginal land claims and government licenses.

Our Australian operations could be affected by native title claims by Aboriginal groups. Australian law recognizes that in some instances native title, that is the laws and customs of the Aboriginal inhabitants, has survived European settlement. Native title will only survive if it has not been extinguished. Native title may be extinguished by an Act of Government, such as the creation of a title that is inconsistent with native title. This may include a grant of the right to exclusive possession through freehold title or lease. Native title may also be extinguished if the connection between the land and the group of Aboriginal people claiming native title has been lost. Each authority to prospect, and license in areas in which we desire to engage in exploration or production activities must be examined individually in order to determine the validity of any native title claim. We may be required to negotiate with any Aborigines who can make a valid claim to having ancestral ties to the areas in which we desire to engage in exploration or production activities. These negotiations could both delay the timing of our exploration or production activities, as well as add an additional layer of cost or a requirement to share revenues if any Aboriginal claimants are proved to have native title rights in our exploration areas.

Our natural gas deliveries to the Madisonville gas treatment plant may be affected by the demands of Crimson Exploration, Inc. (Crimson) and other third parties for access to the plant, and as a result, our access to the plant could be restricted.

We are dependent upon the Madisonville gas treatment plant to treat our natural gas. We have committed all natural gas production from our interest in the Madisonville Project to MGP, which has in turn committed to provide treatment capacity of up to 68 MMcf/d for our natural gas. Third parties may seek access to the gas treatment plant through regulatory proceedings, which could restrict our access to the plant, disrupt our production operations and negatively impact our revenues. An example of such a proceeding is the complaint filed by Crimson with the Texas Railroad Commission described under Properties Description of the Properties Texas The Madisonville Gas Treatment Plant and Gathering Facilities. On August 9, 2006, the Texas Railroad Commission issued an order requiring MGP to ratably process, take, transport or purchase natural gas produced by Crimson into the Madisonville gas treatment plant. The gas treatment plant is currently operating at capacity. There is no guarantee that we will be able to maintain full access to treatment capacity of up to 68 MMcf/d at the Madisonville Plant at all times because, for example, Crimson now has the right to have its natural gas treated at the plant, which will reduce the plant s ability to treat all of our natural gas, unless the plant s capacity is further expanded.

Political and/or economic conditions in Indonesia, Australia, Canada or the United States could change in manners that negatively affect our operations and prospects in those countries.

Our business activities in Indonesia, Australia, Canada and the United States are subject to political and economic risks, including: loss of revenue, property and equipment as a result of unforeseen events like expropriation, nationalization, war, terrorist attacks and insurrection; increases in import, export and transportation regulations and tariffs, taxes and governmental royalties; renegotiation of contracts with governmental entities; changes in laws and policies governing operations of foreign-based companies; exchange controls, currency fluctuations and other uncertainties arising out of foreign government sovereignty over international operations; laws and policies affecting foreign trade, taxation and investment; and the possibility of being subject to the exclusive jurisdiction of foreign courts in connection with legal disputes and the possible inability to subject foreign persons to the jurisdiction of courts in the United States.

Terrorist attacks could have an adverse effect on our oil and natural gas operations, especially overseas.

To date, our operations have not been disrupted by terrorist activity. It is uncertain how terrorist activity will affect us in the future, or what steps, if any, the Indonesian, Australian, Canadian or American government may take in response to terrorist activities. The attack on the New York World Trade Center in 2001 and the subsequent wars in Afghanistan and Iraq have increased the likelihood that U.S. citizens and U.S. owned interests may be targeted by terrorist groups operating both in the United States and in foreign countries, especially in Indonesia.

If we do not satisfy the work requirements of our Production Sharing Contract (PSC) and exploration permits, the Indonesian and/or the Australian government may terminate all or part of our contracts. Please see the Glossary for a definition of Terms.

Our Indonesian PSCs and Australian exploration permits require us and our partners to undertake work by specified dates in order to maintain our oil and natural gas rights. See Properties Description of the Properties Indonesia and Australia. We may not be able to satisfy our contractual obligations. If we do not otherwise comply with the work requirements of the PSCs and exploration permits, or successfully renegotiate the terms, all or part of one or more of our contracts may be terminated. If these contracts are terminated, we would also lose all of our investment in that overseas prospect. If we forfeit our interest in the contract or permit areas, it will be necessary to record an impairment write-down equal to the net capitalized costs recorded for the area forfeited. This could have a material adverse impact on our financial condition and results of future operations in future periods. On September 29, 2006, we sold 70% of our interest in C-G Bengara to CNPC. C-G Bengara owns 100% of the underlying rights in the Indonesian contract area known as the Bengara Block. CNPC has agreed to fund our unmet work commitments in the Bengara Block. As discussed in greater detail under Properties in this report, C-G Bengara is subject to prior work commitments for the nine-year period ended December 3, 2006 requiring total expenditures of $24 million. As of September 30, 2006, C-G Bengara had met approximately $6.3 million of the $24.0 million required expenditures, leaving an approximate $17.7 million shortfall. The applicable governing authority granted a deferral of the prior years commitments until December 2006 and we expect to receive an additional deferral until December 2007. If we do not satisfy the prior and future work commitments and if we fail to secure further deferrals of such commitments, we will need to record an impairment charge equal to the amount of costs capitalized which were approximately $562,000 as of December 31, 2006, and we may lose all of our rights in the Bengara Block.

We may not be able to sell our natural gas production in Indonesia, limiting our ability to obtain a return on our investment there.

Our Indonesian operations lack a local market for natural gas, and if we produce natural gas in Indonesia, it will most likely have to be transported to an area where there is a demand. If no market for natural gas develops in Indonesia, we may incur costs for transportation. If we are not able to sell our natural gas production at a commercially acceptable price or at all, we may not be able to obtain a return on our investment in our Indonesian property.

We could lose our ownership interests in our properties due to a title defect of which we are not presently aware.

As is customary in the oil and gas industry, only a perfunctory title examination, if any, is conducted at the time properties believed to be suitable for drilling operations are first acquired. Before starting drilling operations, a more thorough title examination is usually conducted and curative work is performed on known significant title defects. We typically depend upon title opinions prepared at the request of the operator of the property to be drilled. The existence of a title defect on one or more of the properties in which we have an interest could render it worthless and could result in a large expense to our business. Industry standard forms of operating agreements usually provide that the operator of an oil and natural gas property is not to be monetarily liable for loss or impairment of title. The operating agreements to which we are a party provide that, in the event of a monetary loss arising from title failure, the loss shall be borne by all parties in proportion to their interest owned.

Our acquisition activities are subject to uncertainties, may not be successful and provide a return to us on our investments.

We have grown primarily through acquisitions and intend to continue acquiring undeveloped oil and gas properties. Although we perform a review of the properties proposed to be acquired, such reviews are subject to uncertainties. It generally is not feasible to review in detail every individual property involved in an acquisition. Ordinarily, management review efforts are focused on the higher-valued properties; however, even a detailed review of all properties and records may not reveal existing or potential problems; nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. Inspections are not always performed on every well, and potential problems, such as mechanical integrity of equipment and environmental conditions that may require significant remedial expenditures, are not necessarily observable even when an inspection is undertaken.

We are dependent upon our key officers and employees and our inability to retain and attract key personnel could significantly hinder our growth strategy and cause our business to fail.

While no assurances can be given that our current management resources will enable us to succeed as planned, a loss of one or more of our current directors, officers or key employees could severely and negatively impact our operations and delay or preclude us from achieving our business objectives. Stuart Doshi, David Creel and Chris Steinhauser, the three members of our senior management team, have a combined experience of approximately 100 years in the oil and gas industry. Although we have entered into employment agreements with Messrs. Doshi, Creel and Steinhauser, we could suffer the loss of key individuals for one reason or another at any time in the future. There is no guarantee that we could attract or locate other individuals with similar skills or experience to carry out our business objectives. We maintain key man insurance with respect to our Chief Executive Officer, Stuart Doshi.

Some of our directors may become subject to conflicts of interest which could impair their abilities to act in our best interest.

Nick DeMare, one of our directors, is a director, officer and/or significant shareholder of other natural resource companies and David Anderson, another one of our directors, is a director and officer of Dundee Securities Corporation, an investment banking firm that was the lead underwriter of our public offering of common stock in Canada and concurrent previous private placement of common shares with qualified institutional buyers in the U.S. Their association with these other companies in the oil and gas business may give rise to conflicts of interest from time to time. For example, they could be presented with business opportunities in their capacities as our directors, which they could, in turn, offer to the other companies for whom they also serve as directors, rather than to us, whose interests might be competitive with ours. Our directors are required by law to act honestly and in good faith with a view to our best interests and to disclose any interest which they may have in any project or opportunity to us; however, their interests in the other companies may affect their judgment and cause such directors to act in a manner that is not necessarily in our best interests.

Our directors and officers hold significant positions in our shares and their interests may not always be aligned with those of our other shareholders.

As of March 30, 2007 our directors and officers beneficially own 24% of our outstanding common stock. See Security Ownership of Certain Beneficial Owners and Management . This shareholding level will allow the directors, officers and certain beneficial owners to have a significant degree of influence on matters that are required to be approved by shareholders, including the election of directors and the approval of significant transactions. The short-term interests of our directors, officers and certain beneficial owners may not always be aligned with the long-term interests of our public shareholders, and vice versa. Because our directors, officers and certain beneficial owners have a significant degree of influence on matters that are required to be approved by our shareholders, they could influence the approval of transactions.

Our failure to manage internal or acquisition-based growth may cause operational difficulties and negatively affect our financial performance.

We expect to experience internal and/or acquisition-based growth, which may bring many challenges. Growth in the number of employees, sales and operations will place additional pressure on already limited resources and infrastructure. No assurances can be given that we will be able to effectively manage this or future growth. Our growth may place a significant strain on our managerial, operational, financial and other resources. Our success will depend upon our ability to manage our growth effectively which will require that we continue to implement and improve our operational, administrative and financial and accounting systems and controls and continue to expand, train and manage our employee base. Our systems, procedures and controls may not be adequate to support our operations and our management may not be able to achieve the rapid execution necessary to exploit the market for our business model. If we are unable to manage internal and/or acquisition-based growth effectively, our business, results of operations and financial condition will be materially adversely affected.

Risks Related to Our Common Stock

The shareholding position of holders of our common stock could be diluted by future issuances and conversions of other securities.

If our options and warrants are exercised for common shares, holders of our common stock will experience immediate and, depending on the magnitude of the exercises, substantial dilution. As of the date of this report, 2,057,855 shares of our common stock are issuable upon exercise of warrants and 3,960,000 shares of our common stock are issuable upon exercise of options.

Investors may be subject to further dilution if we sell additional common shares or issue additional common shares in connection with future financings. If a significant number of our common shares are sold in the public market, the market price of our common shares could be depressed. This could hamper our ability to raise capital by issuing additional equity securities.

Our results may be affected by fluctuations in currency exchange rates.

Our financial statements are reported in U.S. dollars and all of our revenue, and most of our operating costs, are currently denominated in U.S. dollars; however, we have operations outside the United States and we plan to expend money in Indonesia, Canada and Australia, where our operating costs will be denominated in local currencies. Fluctuations in exchange rates may increase our relative cost of operating in these countries, and may therefore have a negative effect on our financial results.

Non U.S. holders of our common shares may be subject to U.S. federal income tax on the sale of our common shares and purchasers may have IRS withholding requirements

Unless certain requirements are met, gain recognized by a non U.S. holder on the sale of our common shares will be subject to U.S. federal income tax at normal graduated rates, and a purchaser will be required to withhold for the benefit of the IRS 10% of the purchase price since we are a United States real property holding corporation. There is an exemption from U.S. federal income tax for non-U.S. holders of 5% or less of our common shares (and to withholding for all non U.S. holders) if our common shares are regularly traded on an established securities market. In the event that 100 or fewer persons own 50% or more of our common shares (which had been, and may now and may continue to be, the case), temporary Treasury Regulations provide that our common shares will be regularly traded on an established securities market for a calendar quarter only if the established securities market is located in the United States and our common shares are regularly quoted by more than one broker or dealer making a market in our common shares; our common shares are currently listed on the American Stock Exchange (which constitutes an established securities market for this purpose) and quotes are being regularly made by at least two broker dealers. There can be no assurance, however, that our common shares will continue to be regularly traded on an established securities market for this purpose in any particular calendar quarter so as to avoid U.S. federal income tax on the sale of our common shares by non-U.S. holders of 5% or less of our common shares and the withholding requirement on the purchaser.

At such time that it is no longer the case that 100 or fewer persons own 50% or more of our common shares, under temporary Treasury Regulations, our common shares would also be regularly traded on an established securities market for a calendar quarter if: (a) our common shares trade, other than in de minimis quantities, on at least 15 days during the calendar quarter; (b) the aggregate number of our common shares traded during the calendar quarter is at least 7.5% of the average number of our common shares outstanding during such calendar quarter (reduced to 2.5% if there are 2,500 or more record shareholders); and (c) in the event that our common shares are traded on an established securities market located outside the United States, the common shares are registered under Sec. 12 of the Securities Exchange Act of 1934 (which they presently are).

There is a limited public market for our common shares, and the ability of our shareholders to dispose of their common shares may be limited.

Our common shares have been listed on The Toronto Stock Exchange since March 2006, and have been trading on the American Stock Exchange since February 15, 2007. We cannot foresee the degree of liquidity that will be associated with our common shares. A holder of our common shares may not be able to liquidate his, her or its investment in a short time period or at the market prices that currently exist at the time the holder decides to sell. The purchase and sale of relatively small common share positions may result in disproportionately large increases or decreases in the price of our common shares. A trade involving a large number of common shares could have an exaggerated effect on the reported market price of our common shares.

Our stock price may fluctuate significantly.

The stock market in general and the market for natural gas and oil exploration companies have experienced price and volume fluctuations that are often unrelated or disproportionate to the operating results or asset values of companies. These broad market and industry factors may seriously impact the market price and trading volume of our common shares regardless of our actual operating performance. The market price of our common stock could also fluctuate significantly as a result of:

- actual or anticipated quarterly variations in our operating results and our reserve estimates;
- changes in expectations as to our future financial performance or changes in financial estimates, if any, of public market analysts;
- announcements relating to our business or the business of our competitors;
- conditions generally affecting the oil and natural gas industry, including changes in oil and natural gas prices;
- speculation in the press or investment community;

- general market and economic conditions;
- the success of our operating strategy; and
- the operating and stock price performance of other comparable companies.

The sale of large numbers of our common stock may depress the market price of our common stock.

The sale of a substantial number of shares of our common stock in the public market, or the perception that substantial sales may occur, could cause the market price of our common stock to decrease. ***Substantially all of the shares of our common stock are freely transferable or will be transferable in compliance with restrictions under the Securities Act of 1933, as amended.***

We will continue to incur significant expenses as a result of being a public company, which may negatively impact our financial performance.

We have incurred and will continue to incur significant legal, accounting, insurance and other expenses as a result of being a public company. The Sarbanes-Oxley Act of 2002, as well as related rules implemented by the Securities and Exchange Commission, or SEC, and the American Stock Exchange, have required changes in corporate governance practices of public companies. Compliance with these laws, rules and regulations has increased our expenses, including our legal and accounting costs, and made some activities more time-consuming and costly. We also believe these laws, rules and regulations have made it more expensive for us to obtain director and officer liability insurance, and in the future we may be required to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage. As a result, it may be more difficult for us to attract and retain qualified persons to serve on our board of directors or as officers. Furthermore, any additional increases in legal, accounting, insurance and certain other expenses that we may experience in the future could negatively impact our financial performance and have a material adverse effect on our results of operations and financial condition.

Item 1B. ***Unresolved Staff Comments***

None.

Item 2. ***Properties***

Our principal executive office consists of 2,956 square feet and is located at One Maritime Plaza, Suite 700, San Francisco, CA 94111.

Description of the Properties

Our current oil and natural gas exploration, appraisal and development drilling activities are focused in four distinct project areas as follows:

- **United States Texas** (onshore East Texas region), **Alaska** (onshore Cook Inlet area) and **California** (onshore San Joaquin basin);

- **Canada Alberta** (central Alberta basin);

- **Indonesia** onshore East Kalimantan Province; and

- **Australia** onshore in two permit areas located in the South Perth basin.

We do not fully insure against all business risks either because such insurance is not available or because premium costs are prohibitive. This is a common practice in the oil and gas industry. We believe our property is adequately insured in view of the nature of our operations and industry practices in this regard.

Texas

Madisonville Project

We own and operate the interest in the Madisonville Project in Madison County, Texas. We own working interests in approximately 2,974 gross and net acres of leases in the Rodessa Formation interval, as well as approximately 2,812 gross and net acres of leases as to depths below the Rodessa Formation interval. We also own a license as to 12.5 square miles of 3-D seismic data over the Madisonville Field. In addition, we have entered into farmout agreements which require us to drill certain wells in order to earn 100% working interest rights in up to 1,742 acres in depths equivalent to the Rodessa Formation interval and deeper.

The Madisonville Field, located approximately 100 miles north of Houston, has produced oil and natural gas from four different horizons above the Rodessa Formation for over 50 years. The field was discovered in 1945 with the Boring No. 1 well, which was drilled to the Rodessa Formation. The well blew out at an uncontrolled rate for three days during a test; however, due to hydrogen sulphide, carbon dioxide and nitrogen in the Rodessa Formation natural gas, the gas reserves were never developed. Over 125 wells were drilled in the Madisonville Field to shallower intervals above the Rodessa Formation. In 1994, nearly 50 years after the initial discovery, United Meridian Corporation (**UMC**) drilled the Magness Well as the first follow-up well into the Rodessa Formation to the Boring No. 1 well. The Magness Well had 139 feet of net pay but the natural gas was found to contain 28% impurities.

UMC previously production tested the Magness Well in 1994 through perforations in the lower most ten feet of the indicated Rodessa Formation pay interval. The well tested at a rate of 12 MMcf/d from this limited interval on a 22/64ths inch choke with flowing wellhead pressures increasing from 3,915 to 3,919 pounds per square inch. In 2001, we re-entered and recompleted the Magness Well. A total of 139 feet of interval has been perforated in the Rodessa Formation at approximately 12,000 feet of depth for this well. The well was production tested over a 12-day period in 2001 on various choke sizes with flowing rates ranging up to approximately 20.8 MMcf/d. We own a 100% working interest (75.1333% net revenue interest) in the Magness Well located in the surrounding production unit consisting of 629 gross and net acres. The Magness Well commenced production in May of 2003.

The first development well, the Fannin Well, was drilled and completed in 2004. We own a 100% working interest (70.5636% net revenue interest) in the Fannin Well located in the surrounding production unit consisting of 704 gross (704 net) acres. A total of 146 feet of indicated pay was perforated in the well and a flow test of the well was completed in December 2004 from the Rodessa Formation at rates of up to 25.7 MMcf/d. We commenced production from the Fannin Well in early 2006.

In 2006, we drilled the Wilson and Mitchell wells. We own a 100% working interest (70% net revenue interest) in the Wilson and Mitchell wells. Presently, the Fannin and Magness wells are producing at a combined restricted rate of approximately 16.5 MMcf/d while the Wilson and Mitchell wells are shut-in awaiting completion and/or pipeline connections. The production rate is presently restricted while awaiting a planned expansion of the Madisonville Field gas treatment plant to 68 MMcf/d treating capacity.

The Madisonville Field is a geologic feature encompassing approximately 4,100 acres at the Rodessa limestone at about 11,800 feet of depth. A 3-D seismic program shot in early 1998 confirmed the size of the structure and slightly increased its size over earlier interpretations.

Our working interest covers the Rodessa Formation at approximately 12,000 feet of depth. The Rodessa reserves are being developed through the recompletion of the Magness Well and the drilling of additional proved and probable undeveloped locations. Production began in May 2003 and stabilized at a rate of 18 MMcf/d of raw gas from the Magness Well. The Magness and Fannin wells are currently producing at a combined restricted rate of approximately 16.5 MMcf/d. Current net sales production is approximately 10 MMcf/d. In addition, we own a working interest in certain leases and farmout rights which cover depths below the Rodessa Formation.

The hydrogen sulphide, carbon dioxide and nitrogen combined comprise about 28% of the gas content. As described below, an unaffiliated third party purchases the untreated natural gas from us at the well site point of delivery for a net price equal to the weighted average price per MMBTU that the third party receives for the natural gas delivered to the sales pipeline less certain gathering, treatment and transportation charges. As a result of the charges, we receive a net price that is substantially lower than we would otherwise receive if the gas did not contain the 28% of impurities. In addition, the high concentrations of hydrogen sulphide and carbon dioxide result in higher capital and operating costs for our wells. For example, the hydrogen sulphide and carbon dioxide are corrosive to the wellbores. This means we have to utilize higher grade specification well tubing and casing which is more expensive than what we would utilize absent the impurities. In addition, we continuously treat the well bores with chemicals designed to inhibit the corrosive effects of the impurities. We also maintain field personnel at or near the wellsites who monitor the wells on a twenty four hour basis and equip the wellsites with extensive safety equipment systems due to the toxic properties of the hydrogen sulphide and carbon dioxide. These factors and others result in higher capital and operating costs for our wells in the Madisonville Project.

The Madisonville Gas Treatment Plant and Gathering Facilities

In order to produce the proven gas reserves from the Rodessa Formation, we developed an onsite plan to treat and remove impurities from the Madisonville Project natural gas in order to meet pipeline-quality specifications. On June 15, 2001, we, through our subsidiary Redwood LP, entered into an agreement, which agreement was subsequently amended and restated, together with certain related agreements (collectively, the **Hanover Agreement**), with Hanover pursuant to which Hanover committed to fund, construct and operate a dedicated natural gas treatment plant to process our Rodessa Formation natural gas. The Hanover Agreement also provided for the installation by Gateway of field gathering pipelines and an approximately nine-mile sales pipeline with an estimated capacity of approximately 70 MMcf/d to transport the Madisonville Field natural gas to a major pipeline. By April of 2003, the construction and installation of Hanover s natural gas treatment plant and Gateway s associated pipeline and gathering facilities were completed. Gas production from the Magness Well commenced in May 2003. We received the first revenues from the sale of natural gas from the Madisonville Project in July 2003. The natural gas plant is currently capable of treating approximately up to 18 MMcf/d of inlet natural gas from the Magness Well.

On July 25, 2005, MGP purchased the natural gas treatment plant from Hanover and purchased the gathering pipelines upstream of the gas treatment plant from Gateway. Concurrent with MGP s purchase of the gas treatment plant and gathering pipelines, we, through our subsidiary Redwood LP, Gateway and MGP terminated the Hanover Agreement and entered into a new agreement, (the **MGP Agreement**), to treat and transport our gas production from the Madisonville Project. As a result of the MGP Agreement, MGP committed to install and make operational additional treating facilities capable of treating 50 MMcf/d, which combined with the capacity of the current in-service treating facilities will represent a total treating capacity of 68 MMcf/d for the Madisonville treatment plant. The MGP Agreement provides that the newly installed gas treatment facilities will be 100% electrically driven when the treatment capacity is expanded. Currently, the existing in-service treatment plant utilizes some of the natural gas produced and delivered from our well(s). The conversion to 100% electricity on the expanded portion of the treatment plant is expected to reduce shrinkage of our natural gas that occurs in the treating process.

Originally, the MGP Agreement required MGP to complete the additional treating facilities by March 1, 2006. However, due to events of force majeure, the additional treating facilities are only now nearing completion. Representatives of MGP have indicated that they expect the full expansion of the treatment plant to 68 MMcf/d capacity can be in place and operational by the second quarter of 2007; however, there can be no guarantee that the expansion will be completed by that time.

We have proceeded to drill and complete our new development wells notwithstanding MGP s delay in completing the expansion of the treatment plant. To the extent that production begins at the new wells before the expansion is completed, as is the case with the Fannin Well which was placed on production in March 2006, production of the wells will be restricted as necessary pending completion of the plant expansion.

The term of the MGP Agreement commenced August 1, 2005 and continues so long as we own any oil and gas leases in the Madisonville Field, provided that it shall terminate on July 31, 2035 unless extended. Under the terms of the MGP Agreement, we have committed all natural gas production from our interest in the Madisonville Project to MGP. MGP purchases the untreated natural gas from us at the well site point of delivery for a net price equal to the weighted average price per MMBTU that MGP receives for the natural gas delivered to the sales pipeline less certain gathering, treatment and transportation charges. The gathering, treatment and transportation price adjustments are described below. All proceeds from MGP s sale of Rodessa Formation gas are deposited in an escrow account and then disbursed in accordance with the joint direction of MGP and ourselves.

The MGP Agreement provides that certain gathering, treating and transportation fees shall be paid to MGP from the escrow account. The MGP Agreement provides that MGP will receive a gathering and marketing fee of $0.07 and $0.01 per Mcf, respectively, of gas measured and delivered to the natural gas treatment plant. In addition, for the first 18,000 Mcf/d of gas measured and delivered to the inlet flange of the gas treatment plant, MGP will receive a treating fee of $1.50 per Mcf. This treating fee will remain in effect until September 30, 2010. For any gas volumes in excess of 18,000 Mcf/d of gas delivered to the inlet flange of the gas treatment plant, MGP will receive a treating fee of $1.10 per Mcf. Beginning October 1, 2010, this fee of $1.10 per Mcf shall be charged for all gas measured and delivered to the plant. One-quarter (1/4) of the foregoing treating fees are adjusted using the Producer Price Index for Industrial Commodities (**PPI**) and one-quarter (1/4) using the Consumer Price Index (**CPI**). One-half (1/2) of the foregoing gathering and marketing fees are adjusted using the CPI. We have the right, upon giving 60 days notice, to terminate the marketing fee whereupon we shall assume the sole responsibility of marketing the natural gas sold. The **PPI** and the **CPI** are price indices published by the U.S. Department of Labor.

For the first 18,000 Mcf/d of gas measured and delivered to the inlet flange of the gas treatment plant, Gateway will receive a transportation fee of $0.10 per Mcf. This fee will remain in effect through July 31, 2008. Beginning August 1, 2008 and terminating on July 31, 2010, the fee shall be reduced to $0.08 per Mcf for the first 18,000 Mcf/d of gas measured and delivered to the inlet flange of the gas treatment plant. For any gas volumes in excess of 18,000 Mcf/d of gas measured and delivered to the inlet flange of the gas treatment plant, Gateway will receive a transportation fee of $0.12 per Mcf measured and delivered from the outlet flange of the plant. This fee will remain in effect through July 31, 2008 and shall be reduced to $0.10 per Mcf thereafter.

After July 31, 2010, this transportation fee shall be $0.10 per Mcf for all volumes delivered from the outlet flange of the plant.

The foregoing gathering, treatment and transportation price adjustments are inclusive of all costs and expenses to gather, separate, treat, dehydrate and transport natural gas produced and delivered from our well(s).

Our natural gas deliveries to the Madisonville gas treatment plant may be affected by third party demands for access to the plant. On July 20, 2005 Crimson Exploration Inc. (**Crimson**) filed a complaint with the Texas Railroad Commission (**TRC**) against Gateway and Hanover. The complaint alleged discrimination by Hanover and Gateway, and requested that the TRC issue an order requiring Hanover and Gateway to ratably process, take, transport, or purchase natural gas produced by Crimson into the Madisonville Field gas treatment plant. The complaint did not allege any wrongdoing by Redwood or Redwood LP; however, the complaint referred to the contractual relationship between each of Redwood LP, Hanover, and Gateway which was terminated July 25, 2005 as the basis for its discrimination complaint. Redwood received a subsequent notice dated January 13, 2006 from the TRC informing Redwood that (i) Crimson had filed a request to docket its complaint against MGP for failure to ratably take gas pursuant to Texas regulations and (ii) a pre-hearing conference was held on January 25, 2006 relating to the complaint. Redwood withdrew from the proceeding.

On January 23, 2006, our counsel received a letter from counsel for MGP reaffirming that regardless of the outcome of the proceedings before the TRC, MGP nonetheless recognizes that it has a contractual obligation to treat 68 MMcf/d of natural gas produced by Redwood LP and delivered to the treatment plant. After consultation with legal counsel, we believe that our contract with MGP is fully enforceable.

On August 9, 2006, the Texas Railroad Commission issued an order requiring MGP to ratably process, take, transport or purchase natural gas produced by Crimson into the Madisonville gas treatment plant. The gas treatment plant is currently operating at capacity. There is no guarantee that we will be able to maintain full access to treatment capacity of up to 68 MMcf/d at the Madisonville Plant at all times because, for example, Crimson now has the right to have its natural gas treated at the plant, which may reduce the plant s ability to treat all of our natural gas, unless the plant s capacity is further expanded.

To date, Crimson has permitted four wells to be drilled to the Rodessa Formation. The drilling of two of these wells has been completed to a depth of approximately 12,635 feet. Crimson has also drilled an injection well for disposal of waste products resulting from the treatment of their natural gas.

We have committed to a three-well drilling program to facilitate the expansion of the gas treatment plant. We have drilled two of the three required wells to the Rodessa formation. The commitment requires us to commence the drilling of the third well sufficient to test the Smackover Formation (estimated to be encountered at approximately 18,000 feet) on or before September 30, 2008. We estimate the 18,000 foot well will cost $10 million to drill and complete. We have granted MGP a security interest in the Madisonville Field properties to secure the three well commitment. The security interest shall be subordinated to any third party lender in the event we secure future debt against the property. MGP has granted us a similar security interest in the gas treatment plant to secure its obligation to expand the treatment plant on a timely basis.

Other Interests in the Madisonville Project

Our working interest in the Madisonville Project is subject to a net profits interest in favor of the third party that sold us our working interests in the Madisonville Project. The net profits interest is 12.5% (proportionately reduced to our interest) of the net operating profits until payout is achieved. After payout, the net profits interest increases to 30% (proportionately reduced to our interest). Payout , for purposes of the net profits interest, is defined and achieved at such time as we have recouped from net operating cash flows our total net investment in the Madisonville Project plus a 33% cash on cash return.

Alaska

The Cook Inlet Alaska CBM Project

We entered into an agreement with Pioneer Oil Company, Inc. (**Pioneer**) dated April 20, 2005, wherein we secured the Cook Inlet Option to acquire a 100% working interest, 81% net revenue interest, in approximately 116,806 acres onshore in Cook Inlet, Alaska. We have since acquired 5,368 additional acres. We believe this acreage to be prospective for both coal bed methane and conventional gas production.

The 122,174 acre lease position consists of two separate target areas that have been selected for exploration. These areas are called the Point MacKenzie and Trading Bay Prospects, respectively.

The Point MacKenzie Prospect is located six miles northwest of Anchorage. The Trading Bay Prospect is located 50 miles west of Anchorage across the Cook Inlet. The Cook Inlet basin contains a thick section of terrestrial Tertiary rocks which includes shales, sandstones, and coals. The coals occur in seams which are commonly 20 feet thick and can be as thick as 70 feet. Accessible onshore areas have 200 to 300 feet of coal shallower than 5,000 feet. Gas content for these coals ranges from 80 to 250 standard cubic feet per ton, but testing is restricted to a very small number of bore holes and is almost completely unknown for most of the inlet.

Markets for natural gas in the Cook Inlet area include power generation, heating, fertilizer production and liquefied natural gas exports. An extensive pipeline system supplies these facilities and crosses the Point MacKenzie Prospect and Trading Bay Prospect lease blocks. These pipelines are only partially filled with gas and could accommodate additional production.

In addition to coal bed methane reserve potential, preliminary log analysis indicates the Point MacKenzie Prospect and Trading Bay Prospect lease blocks may also contain conventional accumulations of natural gas reserves in Tertiary sandstones.

The terms of the Cook Inlet Option provide for us to pay total consideration of $20 per acre, or approximately $2.3 million, for the leases. The Cook Inlet Option provides that we will pay the total lease consideration in two installments. We paid the first installment totaling $1,068,063 on August 17, 2005 and we have received assignment of the 100% working interest in the leases. Within three years from the date of receipt of assignment of the 100% working interest in the leases, we have the option to conduct a $2.5 million work program consisting of, but not limited to, a multiple test well drilling program on the leases over a three-year period, and, after completion of the work program and an evaluation of the results, to remit the final additional acreage consideration of $10 per acre for the leases. The Cook Inlet Option provides that if we fail to pay the lease consideration when due, fail to perform the work program or otherwise default under the Cook Inlet Option, we shall forfeit our interest and reassign the leases to Pioneer, and we will have no further liability to Pioneer.

Approximately one to two miles of pipeline will be required to tie in any wells drilled at a currently preferred location at the Point MacKenzie Prospect, and approximately four to five miles of the pipeline will be required to tie in any wells drilled at a currently preferred location at the Trading Bay Prospect. We have not yet prepared an estimate of the cost to tie these wells in.

We are aware of two major pipelines which transverse the acreage blocks, the Enstar 20 line and the UnoCal-Marathon 16 line. We estimate the UnoCal-Marathon 16 line presently has available unused capacity of approximately 40 MMcf/d. In addition, we estimate the Enstar 20 line has available unused capacity of approximately 100 MMcf/d.

California

Lokern Project

We have a working interest in the Lokern Project, located in the southern San Joaquin basin, near Bakersfield, California. The primary exploration objective is the Miocene Stevens formation. The secondary objectives include the Miocene Reef Ridge and Pliocene Etchegoin sands. The Stevens formation is Upper Miocene age.

The Lokern Project is being developed in part as a result of positive results from the Machii-Ross Ackerman show well drilled in 1979 on acreage currently controlled by us. Based on log analysis, we believe that well had approximately 240 feet of potential net oil pay and an additional 150 feet of potential pay in the Stevens zone. The Machii-Ross Ackerman well was drilled to a depth of 15,078 feet by Machii-Ross Petroleum Company and was plugged and abandoned as a dry hole. We believe, based on our log analysis, that the well may have been a bypassed producer.

We expect that a well will be drilled, either by us or through a farmout arrangement with a third party, to a depth of 15,000 feet by 2008.

Based on our review of title information from public authorities and other publicly available sources, we believe that we have a 100% working interest in the Lokern Project. As is customary in the U.S. oil and gas industry, we will not conduct a thorough title review with respect to our interest in the Lokern Project until we have made a definitive decision to drill in a particular lease area.

Alberta

Pinnacle Reef Project

The Pinnacle Reef Project is located in Alberta, Canada, approximately 100 miles northeast of Calgary. The primary exploration objective is Leduc D3 Pinnacle Reefs. A Leduc D3 Pinnacle Reef refers to a certain type of reef complex within the Leduc formation. Secondary objectives will include the shallower Nisku formation and deeper Winnipegosis formation.

These formations are expected to be encountered at depths of less than 10,000 feet. We, through our wholly-owned subsidiary, GeoPetro Canada, have acquired seismic data and plan to participate in the drilling of test wells.

We have a 56.25% working interest in 2,560 leased acres.

Indonesia

C-G Bengara owns 100% of the underlying rights to explore for and produce oil and natural gas within the contract area designated as the Bengara II Block, which rights have been granted under a production sharing contract dated December 4, 1997 (the **Bengara II PSC**) with Pertamina. Until recently, we owned 40% of CG Bengara and Continental Energy Corporation (Continental) owned the remaining 60% and, through it, the rights to the Bengara II PSC. On September 29, 2006, we executed a definitive agreement to sell 70% of our interest in C-G Bengara to CNPCHK (Indonesia) Limited (CNPC). We have retained a 12% stake in C-G Bengara and the Bengara II PSC. Continental has likewise sold its interest and retained an 18% interest in C-G Bengara and the Bengara II PSC.

The Bengara Block is located in the Tarakan Basin, mostly onshore but partially offshore astride the Bulungan River Delta in the Indonesian province of East Kalimantan. It originally covered a single contiguous area of approximately 1.2 million gross acres, of which 300,000 gross acres were relinquished in 2001 by C-G Bengara in accordance with the terms of the Bengara II PSC. A portion of our holdings in Indonesia was scheduled to be relinquished effective December 3, 2005. We have requested a postponement of the relinquishment from BP Migas; however, if the postponement is not granted, then a further 300,000 gross acres will be relinquished.

Geologically, the Bengara Block lies in the Tarakan Basin near major oilfields at Tarakan and Bunyu. More than 320 MMbbls and 96 bcf of natural gas have been produced from the Tarakan Basin according to records maintained by BP Migas. The Tarakan Basin is one of five sedimentary basins making up eastern Borneo on the eastern margin of the broad area of Southeast Asia and are some of the deepest in Indonesia, with seismic surveys indicating depths greater than 20,000 feet in the Tarakan Basin southeast of Bunyu Island.

The Makapan Gas Field

Since 1938, only two wells have been drilled in the Bengara Block, one of which resulted in the discovery of the Makapan Gas Field. The Muara Makapan No. 1 well was drilled in 1988 by P.T. Deminex Indonesia from a swamp barge positioned on one of the Bulungan River Delta mouth channel distributaries. The well was drilled to a total depth of 10,800 feet and tested 19.5 million cubic feet of gas per day together with 600 bbls of 54 degree API condensate per day from a 33 feet thick sandstone section near 6,000 feet. The well was plugged and abandoned as a natural gas discovery. Several other gas zones indicated on logs were not tested. The well was not produced nor were any confirmation wells drilled due to the lack of a local natural gas market at the time the well was drilled. The Makapan Gas Field gas is a Wet gas with a high LPG fraction which may be commercial to extract at the wellhead for a third revenue source in addition to the gas and condensate. The Makapan Gas Field lies mostly offshore in very shallow water, less than 10 feet, amidst numerous islands of the Bulungan River Delta.

Exploration in the Bengara Block

We believe that the key to successful prospecting in the Bengara Block will be the identification of traps and understanding sand distribution.

A striking feature of the Bengara Block is the presence of a few old wellbores actively leaking oil into surface lakes. Site investigations with a wireline unit are planned to determine the depths of the existing wellbores and obtain rock and oil samples at depth if possible.

Nearly 2,200 line kilometres of 2-D seismic data available within the Bengara Block appear to be adequate for both detailed and reconnaissance interpretation purposes. Some localized areas may benefit from reprocessing. New seismic data is required in places where insufficient data exists and for prospect confirmation in other locations. Field geology surveys are expected to confirm initial drilling targets without the need for additional seismic data at this time.

Several separate and unique geologic plays within the Bengara Block as well as a number of prospects and leads have been identified. Some well-defined prospects present immediate drilling targets. Exploration within the Bengara Block is in its formative stages and it is premature to make meaningful resource or reserve estimates. However, the existing exploration work to date indicates that there may be potential petroleum accumulations in the Bengara Block. Analysis of source rocks indicates a propensity for both oil and natural gas.

Terms of Participation in the Bengara Block

The Bengara II PSC is a standard terms PSC employed by BP Migas for all oil and natural gas concessions in Indonesia. Generally, the joint venture participants are entitled to receive, from production proceeds, 100% of expenditures in the block as cost recovery . Once these costs are recovered, C-G Bengara is entitled to a production share of approximately 26.7% of oil produced and 62.5% of all natural gas produced. We will be entitled to 12% of C-G Bengara s share of any such production. Sharing terms for certain categories of oil vary slightly as defined in the Bengara II PSC.

The term of the contract is thirty years or a shorter period if C-G Bengara elects to terminate its obligations under the contract or if no commercial hydrocarbons are discovered within the contract area. At the end of six years, unless mutually extended by C-G Bengara and BP Migas, the contract expires if no commercially producible hydrocarbons have been discovered in the contract area. C-G Bengara and BP Migas have mutually extended the early termination provisions until December 3, 2008. C-G Bengara may terminate the contract at any time by relinquishing all of its rights and obligations under the contract area.

C-G Bengara is required to relinquish 25% of the contract area within the first three years of the contract, a further 25% of the contract area within six years from the commencement of the contract and an additional area within the first ten years so that the area retained thereafter shall not be in excess of 970 square kilometres, or 20% of the original total contract area, whichever is less. C-G Bengara may designate which areas are to be relinquished subject to approval by BP Migas. C-G Bengara s obligation to relinquish parts of the original contract area under these provisions does not apply to the surface area of any field in which petroleum has been discovered. In 2001, C-G Bengara relinquished approximately 300,000 gross acres of the original 1.2 million gross acre contract area pursuant to the requirement to relinquish 25% of the contract area within the first three years of the PSC. The 300,000 gross acres relinquished were located in the western portion of the block which C-G Bengara considered to be the least prospective for oil and natural gas. C-G Bengara was required to relinquish an additional 25% of the contract area in December 2005. However, C-G Bengara received a one-year postponement of the relinquishment until December 3, 2006 from BP Migas. We have requested a further postponement of the relinquishment until December 2007; however, if the postponement is not granted, then a further 300,000 gross acres will be relinquished.

C-G Bengara is required to pay to BP Migas specified amounts based on achieving certain cumulative production quantities of crude oil from the contract area when and if commercial production is established. These production bonuses are as follows:

Cumulative Production	**Cash Bonus Due**
25,000,000 boe	$ 500,000
60,000,000 boe	$ 1,500,000
100,000,000 boe	$ 2,500,000

In order to maintain the Bengara II PSC in effect, C-G Bengara is required to complete the following work programs and expenditures during the first ten years of the contract, unless the requirement is extended or waived by BP Migas:

Contract Year	Work Program	Amount	Our 12% Share
1998	Geologic and geophysical studies	$ 500,000	$ 60,000
1999	Seismic reprocessing	500,000	60,000
2000	Drill two wells	6,000,000	720,000
2001	Geologic and geophysical studies	1,000,000	120,000
2002	Drill one well	5,000,000	600,000
2003	Acquire seismic	3,750,000	450,000
2004	Drill one well	5,250,000	630,000
2005	Evaluate well results	1,000,000	120,000
2006	Geologic and geophysical studies	1,000,000	120,000
2007	Geologic and geophysical studies	1,000,000	120,000
	TOTAL	$ 25,000,000	$ 3,000,000

To date, C-G Bengara has not fulfilled the minimum work and cash expenditure requirements described above. These work and expenditure requirements were extended by BP Migas until December 2006 and an additional deferral until December 2007 has been requested. In accordance with the terms of the contract and with BP Migas consent, C-G Bengara may carry forward such yearly commitments to subsequent periods provided that BP Migas consents to any additional extensions. Failure of C-G Bengara to pay such commitments when due or to farm out its interest to an industry partner, which pays such obligation, may result in the forfeiture of its interest in, and rights to explore, drill and develop, the Bengara Block.

Upon establishing commercial production, if ever, C-G Bengara and BP Migas shall share ratably in the first 20% of oil and natural gas produced in the contract area within a given year according to the percentages specified below. After the first 20% of production, C-G Bengara is entitled to receive 100% of production until cost recovery has been achieved. Cost recovery generally includes 100% of the operating and drilling costs and depreciation of fixed assets applicable to oil and natural gas operations within the contract area. After C-G Bengara has received oil and natural gas production with a value sufficient to achieve cost recovery in a given year, C-G Bengara and BP Migas shall then share ratably in the production according to the percentages specified below:

Description	BP Migas	C-G Bengara	Our net share
Oil production	73.2143 %	26.7857 %	3.2143 %
Gas production	37.5 %	62.5 %	7.5 %

Thus, once we have achieved cost recovery, we will end up receiving approximately 3.2% and 7.5% of the proceeds from the sale of oil and gas, respectively.

Upon the completion of five years after commercial production commences, C-G Bengara is further subject to a domestic market obligation. This obligation requires C-G Bengara to sell and deliver to BP Migas, to meet Indonesia s domestic crude oil needs, a specified quantity of crude oil at a price which is only 15% of the market price of the oil. However, for new fields, for a period of five years starting on the month of the first delivery of crude oil produced from a new field, the fee per barrel for such crude oil supplied to the Indonesian domestic market shall be the market price, with the condition that the excess over the 15% of market price shall preferably be used to assist financing of continued exploration efforts in the contract area.

Upon the first commercial discovery of oil or natural gas in the contract area, BP Migas has the right to demand that 10% of C-G Bengara s undivided interest in the total rights and obligations under the Bengara II PSC be offered to itself or an entity owned by Indonesian nationals. The 10% interest shall be offered at a dollar amount equal to 10% of C-G Bengara s cumulative costs incurred in the contract area.

C-G Bengara is subject to prior work commitments, as previously described under Terms of Participation in the Bengara Block , for the nine-year period ended December 3, 2006 requiring total expenditures of $24 million. As of September 30, 2006, C-G Bengara had met approximately $6.3 million of the $24.0 million required expenditures, leaving an approximate $17.7 million shortfall. BP Migas, the applicable governing authority, has granted a deferral of the prior years commitments until December 2006. We have requested and expect to receive an additional deferral until December 2007.

Current and Planned Activities in the Bengara Block

In accordance with the terms of our agreement dated September 29, 2006 to sell 70% of our interest in C-G Bengara to CNPC, CNPC has:

1. Purchased 14,000 and 21,000 shares of C-G Bengara from us and Continental, respectively, at a cost of $1 per share. As a result of the transaction, we and Continental own 6,000 and 9,000 C-G Bengara shares, respectively, retaining a 12% and 18% interest in C-G Bengara, respectively.

2. Paid the sum of $18.7 million (the **Earning Obligation**) into a special joint venture account at a Hong Kong international bank. The funds will be under joint signature control of CNPC, ourselves and Continental, and will be expended exclusively to pay for 2006 and 2007 exploration drilling in the Bengara II PSC area, including four exploration wells included in C-G Bengara s approved 2006 work program and budget.

3. Agreed to provide development loans to pay 100%, and thereby carry our share and Continental s share of all C-G Bengara s exploitation, drilling, and development expenditures attributable to the Bengara II PSC, after the Earning Obligation funds are expended, until an additional amount of U.S. $41.3 million over and above the Earning Obligation funds has been expended.

4. Agreed to pay a cash bonus totaling $5,000,000, in the proportions of $2,000,000 to us and $3,000,000 to Continental, respectively, contingent upon and within fourteen business days of the receipt by C-G Bengara of the written approval from governmental authorities approving the development of the first commercial oil or gas discovery within the Bengara II PSC contract area.

The Earning Obligation funds of $18.7 million, together with the $6.3 million previously spent, will satisfy all of the past and future work commitments on the Bengara II PSC.

BP Migas previously waived the work program expenditure requirement provisions of the Bengara II PSC until December 2006. We did not satisfy our work expenditure commitments by December 2006, and if BP Migas does not grant any further deferrals of those commitments, we may be compelled to relinquish our interest in the contract area. In the event we relinquish our interest, we will record an impairment expense equal to the costs which have been capitalized in connection with the contract area. As of December 31, 2006, we have capitalized costs totaling approximately $562,000 in respect to the contract area.

CG Xploration

In November 2005, we and Continental formed CG Xploration to pursue new venture oil and gas exploration and production projects and obtain new exploration concessions in Indonesia. CG Xploration Inc. is incorporated in Delaware and is owned 50% by us and 50% by Continental. CG Xploration Inc. will actively pursue and may acquire new venture opportunities on behalf of ourselves and Continental. CG Xploration Inc. is evaluating production acquisition opportunities and may participate in several undeveloped field exploitation opportunities and older field rehabilitation opportunities. To date, CG Xploration has made no acquisitions.

Australia

We have entered into joint exploration agreements covering two exploration permit areas in Australia.

Whicher Range

We presently own a 26.22% working interest in the Whicher Range Gas field project (the **Whicher Range Project**). The Whicher Range Project is located in the South Perth basin of Western Australia. The field was discovered by Union Oil Company (**Unocal**) in 1968. To date, a total of five wells have been drilled on the Whicher Range structure. We have correlated each of these wells and interpret the gas bearing intervals in each well to be in the same stratigraphic interval. These five penetrations provide control to extrapolate the existence of natural gas across this large geologic structure. The discovery well encountered 581 feet of net natural gas pay over 1,844 feet of gross interval and was drill stem tested at a combined rate of 5.5 MMcf/d from six intervals. The natural gas discovery was in the Sue Coal Measures sand, a tight sandstone of Permian age. Due to the lack of a market for natural gas at the time the well was drilled, Unocal did not develop the discovery. In 1995, we acquired a working interest in the 200,895 gross (52,675 net) acre permit from the government of Western Australia, which was subsequently designated as Exploration Permit EP 408 (**EP 408**), that included the known Whicher Range gas field. Oil and Gas Communications Pty Ltd. is the operator of the Whicher Range Project.

The most recent well on the Whicher Range structure, the Whicher Range No. 5 well, was drilled in 2003. A total of 300 feet of estimated net pay were identified from well logs. Production casing was cemented in place from approximately 14,000 feet to surface.

During August and September 2004, a multi-zone hydraulic fracture stimulation program (**frac**) was performed on the Whicher Range No. 5 well over four sandstone sequences starting from the bottom zone and progressing zone by zone to the uppermost zone. Diesel fuel was pumped into the formations at very high pressures attempting to initiate fractures. A very hard and coarse grained proppant material was then pumped into each fracture during the operation to hold the fractures open after the pressure was released. A subsequent flow test from all of the zones together yielded marginal gas rates and a decision was made to plug and abandon the well. We are attempting to sell or farm out our interest in the EP 408 permit.

Other Australian Exploration Permit

In addition to EP 408, we own a 32.588% working interest in Exploration Permit 381 located in the South Perth basin, Southwest Australia, consisting of 330,000 gross (107,540 net) acres.

Natural Gas Reserves

Our estimated total net proved reserves of natural gas and oil as of December 31, 2006, 2005 and 2004, and the present values of estimated future net revenues attributable to those reserves as of those dates, are presented in the following tables.

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

Proved developed nonproducing reserves means reserves expected to be recovered from zones behind casing in existing wells.

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

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(iii) Estimates of proved reserves do not include the following:

(A) oil that may become available from known reservoirs but is classified separately as indicated additional reserves ;

(B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;

(C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and

(D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved undeveloped reserves means reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimate for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

The 2006 estimates were prepared by MHA Petroleum Consultants, independent reservoir engineers, and are part of their reserve reports on our natural gas and oil properties. The 2005 and 2004 estimates were prepared by Sproule Associates Inc., independent reservoir engineers, and are part of their reserve reports on our natural gas and oil properties. MHA Petroleum Consultants and Sproule Associates Inc. s estimates were based on a review of geologic, economic, ownership and engineering data that we provided. In estimating the reserve quantities that are economically recoverable, MHA Petroleum Consultants and Sproule Associates Inc. used end-of-period natural gas and oil prices. In accordance with U.S. Securities and Exchange Commission regulations, no price or cost escalation or reduction was considered. All of our proved reserves are attributable to our Madisonville Project in Madison County, Texas.

	AS OF DECEMBER 31,		
	2006 (MMcf)	**2005 (MMcf)**	**2004 (MMcf)**
Proved developed	12,335	4,645	4,448
Proved developed non-producing	12,365	8,903	7,037
Proved undeveloped		7,881	6,923
Total	24,600	21,428	18,408

In accordance with Securities and Exchange Commission regulations, estimates of our proved reserves and future net revenues are made using sales prices estimated to be in effect as of the date of such reserve estimates and are held constant throughout the life of the properties, except to the extent a contract specifically provides for escalation. Estimated quantities of proved reserves and future net revenues therefrom are affected by natural gas and oil prices, which have fluctuated significantly in recent years. We filed reports with the U.S. Department of Energy in May 2006 and the Alberta Securities Commission in June 2006 that included total proved reserves inclusive of royalties and net profits interests as of December 31, 2005 totaling 39,493 MMcf. The total net proved reserves, excluding royalties and net profits interests, as of December 31, 2005 was 21,428 MMcf. The difference between the two numbers represents proved reserves attributable to royalties and net profits interests.

Standardized Measure of Discounted Future Net Cash Flows

For purposes of the following disclosures, estimates were made of quantities of proved reserves and the periods during which they are expected to be produced. Future cash flows were computed by applying year-end prices to estimated annual future production from proved gas reserves. The average year-end prices for gas were as indicated below. Future development drilling and production costs were computed by applying year-end costs to be incurred in producing and further developing the proved reserves. Future income tax expenses were computed by applying, generally, year-end statutory tax rates (adjusted for permanent differences, tax credits and allowances) to the estimated net future pre-tax cash flows. The discount was computed by application of a 10% discount factor. The calculations assume the continuation of existing economic, operating and contractual conditions. However, such arbitrary assumptions have not proven to be the case in the past. Other assumptions of equal validity could give rise to substantially different results.

	YEAR ENDED DECEMBER 31,		
	2006	**2005**	**2004**
	(in thousands)		
Future cash inflows	$ 101,867	$ 162,459	$ 90,815
Future production costs	(37,783)	(60,176)	(30,240)
Future development costs	(1,075)	(6,560)	(4,860)
Future income taxes	(8,128)	(18,941)	(9,609)
Future net cash flows	54,882	76,782	46,106
10% annual discount	(8,341)	(13,293)	(8,455)
Standardized measure of discounted future net cash flows	$ 46,541	$ 63,489	$ 37,651

Pricing Assumptions

SEC regulations require that the gas and oil prices used in the MHA Petroleum Consultants and Sproule Associates Inc. reserve reports included herewith are the period-end prices for natural gas at December 31, 2006, 2005 and 2004, respectively. These prices are projected without inflation for the life of the wells included in the reserve reports. The pricing assumptions are listed below:

AVERAGE YEAR-END PRICE		
2006 REPORT **Gas ($/MMBtu)**	**2005 REPORT** **Gas ($/MMBtu)**	**2004 REPORT** **Gas ($/MMBtu)**
$ 5.40	$ 7.80	$ 5.20

Drilling Activities

The following indicates the number of natural gas and oil wells drilled during the periods indicated.

	Productive		**Dry**		**Total Wells**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Year ended December 31, 2006						
Exploratory	0	0	0	0	0	0
Development	2	2	0	0	2	2
Year ended December 31, 2005						
Exploratory	0	0	0	0	0	0
Development	0	0	0	0	0	0
Year ended December 31, 2004						
Exploratory	0	0	1	0.75	1	0.75
Development	1	1	0	0	1	1

Acreage and Productive Wells

The following table sets forth our ownership interest in undeveloped acreage, developed acreage and productive wells in the areas indicated where we own a working interest as of December 31, 2006. Gross represents the total number of acres or wells in which we own a working interest. Net represents our proportionate working interest resulting from our ownership in gross acres or wells. Productive wells are wells in which we have a working interest and that are capable of producing natural gas or oil. Wells that are completed in more than one producing horizon are counted as one well.

	Undeveloped Acreage		Developed Acreage		Producing Wells		Non-Producing Wells	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Indonesia	900,000	108,000						
Australia	530,896	160,216					2	0.52
Texas	3,383	3,383	1,333	1,333	2	2.00	4	3.02
California	1,280	1,280						
Alaska	122,174	122,174						
Total	1,557,733	395,053	1,333	1,333	2	2.00	6	3.54

The following table sets forth as of December 31, 2006, the expiration periods of the gross and net undeveloped acreage:

	Undeveloped Acreage					
	United States		Indonesia		Australia	
	Gross	Net	Gross	Net	Gross	Net
Twelve months ended						
December 31, 2007	2,135	2,135	900,000	108,000		
December 31, 2008	123,691	123,691			530,896	160,216
December 31, 2009	526	526				
December 31, 2010	44	44				
December 31, 2011 and later	441	441				
Total	126,837	126,837	900,000	108,000	530,896	160,216

Volumes, Prices and Production Costs

Substantially all of our production is derived from our Madisonville Project in Madison County, Texas. The following table sets forth information with respect to our production volumes, average prices received and average production costs for the periods indicated:

	YEAR ENDED DECEMBER 31,		
	2006	2005	2004
Production:			
Natural gas (MMcf)	2,229	1,991	2,317
Natural gas (MMcfd)	6.81	5.46	6.35
Average Sales Prices (1)			
Natural gas ($per Mcf)	$ 3.01	$ 4.01	$ 2.51
Lease Operating Expense			
($per Mcf)	$ 0.72	$ 0.44	$ 0.34

(1) Represents sales price realized net of treatment costs.

Business Risks and Other Special Considerations

Refer to Risk Factors in this report for a discussion of business risks and other special considerations.

Item 3. ***Legal Proceedings***

From time to time, we are party to litigation or other legal and administrative proceedings that we consider to be a part of the ordinary course of our business. Currently, we are not involved in any legal proceedings nor are we party to any pending or threatened claims that could, individually or in the aggregate, reasonably be expected to have a material adverse effect on our financial condition, cash flow or results of operations.

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

Not applicable.

PART II

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

On February 15, 2007, our common stock commenced trading on the American Stock Exchange under the symbol GPR . Our common stock previously traded in the United States over-the-counter market in the Pink Sheets under the symbol GPRC . Our common stock is also listed on the Toronto Stock Exchange under the symbol GEP.s . Those shares of our common stock which trade on the Toronto Stock Exchange may not presently be purchased by United States persons or persons in the United States pursuant to SEC Regulation S. On March 28, 2007, the last reported sale prices for our common stock on the American Stock Exchange and Toronto Stock were $4.95 and $2.80, respectively. The following table sets forth the high and low sale prices of our common shares as reported on the American Stock Exchange and the Toronto Stock Exchange and bid prices as quoted in the United States in the pink sheets over-the-counter market for the periods presented. Prior to the first quarter of 2006, there was no trading market for our common shares.

	American Stock Excchange (1)		**Toronto Stock Excchange** (2)		**U.S. Pink Sheets**	
	High	**Low**	**High**	**Low**	**High**	**Low**
2007						
First Quarter through March 28, 2007	6.25	2.66	3.39	2.61	4.10	2.66
2006						
Fourth Quarter	N/A	N/A	$ 3.05	$ 2.35	$ 3.25	$ 2.25
Third Quarter	N/A	N/A	$ 3.40	$ 2.76	$ 3.50	$ 2.25
Second Quarter	N/A	N/A	$ 3.98	$ 3.15	$ 9.00	$ 3.68
First Quarter	N/A	N/A	$ 3.50	$ 3.50	$ 10.05	$ 3.50

(1) Our common stock commenced trading on the American Stock Exchange on February 15, 2007.

(2) Our common stock is quoted in U.S. dollars on the Toronto Stock Exchange. Our common stock commenced trading on the Toronto Stock Exchange on March 30, 2006.

As of March 28, 2007, there were 494 holders of record of our common shares.

Over-the-counter market quotations reflect inter-dealer prices, without retail mark-up, mark-down or commission, and may not necessarily represent actual transactions.

For the year the year ended December 31 2006, the number of unoptioned shares available at the beginning and at the close of the year for the granting of options under our option plan(s) was as follows:

	Number of securities remaining available for future issuance under equity compensation plans
January 1, 2006	1,124,750
December 31, 2006	994,750

There were no changes in the exercise price of outstanding options through cancellation or reissuance or otherwise.

Dividends

On March 28, 2007, all outstanding shares of Series AA 8% Convertible Preferred Stock converted to common shares. Dividends on Series AA preferred stock are no longer payable. The holders of Series AA preferred stock were entitled to receive ratably such cash dividends, as were declared from time to time by the board of directors out of funds legally available therefor and, when declared, dividends were paid at the rate of $0.28 per share per annum, paid on a calendar quarter basis. Prior to the conversion, we had declared and paid dividends on a quarterly basis with respect to all outstanding shares of Series AA preferred stock at the rate of $0.28 per share per year from the time the Series AA stock was issued.

The holders of our common stock shall be entitled to receive ratably such lawful dividends as may be declared by the Board of Directors. We have never paid any dividends, whether cash or property, on our common stock. For the foreseeable future it is anticipated that any earnings which may be generated from our operations will be used to finance our growth and that dividends will not be paid to common stockholders.

We have never paid any dividends, whether cash or property, on our common stock. No dividend on our common stock may be paid unless, at the time of such payment, all accrued dividends on our Series AA Preferred Stock have been paid. Dividends on Series AA preferred stock are no longer payable since all of which converted to common stock on March 28, 2007. The holders of our common stock shall be entitled to receive ratably such lawful dividends as may be declared by the Board of Directors. For the foreseeable future it is anticipated that any earnings which may be generated from our operations will be used to finance our growth and that dividends will not be paid to common stock shareholders.

Recent Sales of Unregistered Securities

During the year ended December 31, 2006, we sold the following securities without registration under the Securities Act:

On January 31, 2006, we issued a $1,000,000 8% unsecured promissory note due January 31, 2007 to one accredited investor. The private placement issuance of the unsecured promissory note was exempt from the registration requirements of the Securities Act pursuant to Section 4(2) of the Securities Act and Rule 506 of Regulation D. The investor in the private placement was an accredited investor, as defined in Rule 501(a). We did not accomplish the offer or sale of the securities sold in the private placement through any manner of general solicitation or general advertising. We made available to the investor, prior to purchase, the opportunity to ask questions and receive answers concerning the terms and conditions of the private placement.

In February 2006, we issued 927,314 Common Shares for proceeds of $3,245,600 as follows:

SHARES	PRICE PER SHARE	FUNDS	ISSUANCE DATE
285,714	3.50	$ 1,000,000	February 1, 2006
428,572	3.50	1,500,000	February 6, 2006
6,743	3.50	23,600	February 15, 2006
71,429	3.50	250,000	February 15, 2006
6,283	3.50	22,000	February 15, 2006
71,429	3.50	250,000	February 15, 2006
28,572	3.50	100,000	February 15, 2006
28,572	3.50	100,000	February 15, 2006
927,314		$ 3,245,600	

These shares were issued to eight accredited investors. The private placement was exempt from the registration requirements of the Securities Act pursuant to Section 4(2) of the Securities Act and Rule 506 of Regulation D. Each of the investors in the private placement was either an accredited investor, as defined in Rule 501(a), or one we reasonably believed to be. The purchase agreement signed by each investor contained customary and appropriate representations and warranties regarding the investor s status as an accredited investor, and that the investor was acquiring the securities for his or her own account and not with a view to resale or distribution. It also contained questions further attesting to his or her status as an accredited investor. In addition, we did not accomplish the offer or sale of the securities sold in the private placement through any manner of general solicitation or general advertising. Moreover, it was disclosed to each investor prior to sale that, except as otherwise may be provided in any registration rights granted to him or her, the securities purchased would not be registered under the Securities Act and could therefore not be resold unless first registered under the Securities Act or an exemption from registration was available. We placed a legend on each certificate representing the securities sold stating that the securities have not been registered under the Securities Act and further setting forth customary and appropriate restrictions on the transferability of the securities. Finally, we made available to each investor, prior to purchase, the opportunity to ask questions and receive answers concerning the terms and conditions of the private placement.

On March 30, 2006, we issued 3,730,021 common shares at an issue price of $3.50 per common share and 519,500 common shares issued on a flow-through basis under the *Income Tax Act* (Canada) at an issue price of $3.85 per common shares for aggregate gross proceeds of $15,055,149. The sale of common shares was conducted (a) outside the United States pursuant to the exemption from registration provided by Regulation S of the Securities Act, and (b) within the United States to six qualified institutional buyers pursuant to Rule 144A. The offering of common shares was underwritten by Dundee Securities Corporation and Westwind Partners Inc. Total underwriting discounts and commissions of $1,053,860 were paid to the underwriters in connection with the sale of common shares.

On December 31, 2006, we issued 75,000 shares of common stock pursuant to an exercise of stock warrants at $2.00 per share for proceeds of $150,000. These shares were issued to three accredited investors. The private placement was exempt from the registration requirements of the Securities Act pursuant to Section 4(2) of the Securities Act and Rule 506 of Regulation D. Each of the investors in the private placement was either an accredited investor, as defined in Rule 501(a), or one we reasonably believed to be. The purchase agreement signed by each investor contained customary and appropriate representations and warranties regarding the investor s status as an accredited investor, and that the investor was acquiring the securities for his or her own account and not with a view to resale or distribution. It also contained questions further attesting to his or her status as an accredited investor. In addition, we did not accomplish the offer or sale of the securities sold in the private placement through any manner of general solicitation or general advertising. Moreover, it was disclosed to each investor prior to sale that, except as otherwise may be provided in any registration rights granted to him or her, the securities purchased would not be registered under the Securities Act and could therefore not be resold unless first registered under the Securities Act or an exemption from registration was available. We placed a legend on each certificate representing the securities sold stating that the securities have not been registered under the Securities Act and further setting forth customary and appropriate restrictions on the transferability of the securities. Finally, we made available to each investor, prior to purchase, the opportunity to ask questions and receive answers concerning the terms and conditions of the private placement.

Use of Proceeds

Our registration statement on Form S-1 (Reg. No. 333-135485) registered up to 16,499,991 shares of our common stock, no par value per share, including 5,943,105 shares of common stock issuable upon exercise of warrants and options, for resale by selling shareholders. The registration statement was declared effective by the Securities and Exchange Commission on February 8, 2007. The offering commenced on February 8, 2007 and has not terminated. We will not receive any proceeds from the sale of our common stock by the selling shareholders under the registration statement; however if all warrants and options to acquire our common stock being registered thereunder are exercised, we will realize cash proceeds of approximately $14,019,681, which we expect to use for general working capital purposes and the drilling of wells in our Texas, Alaska, California and Indonesian prospects.

If less than the $14,019,681 proceeds are realized from the exercise of such warrants and options, the proceeds will be spent in the following order of priority:

1. Alaska Cook Inlet Project, up to approximately $3.0 million will be expended for the drilling of pilot program wells.

2. Madisonville Project, Madison County, Texas. Up to approximately $10 million will be expended in the Madisonville Field area towards the drilling and completion of one deep exploratory well location to an estimated depth of 18,000 feet.

3. General working capital.

We do not know if, or how many, of the warrants or options will be exercised. This is our best estimate of our use of proceeds generated from the possible exercise of warrants or options based on the current state of our business operations, our current plans and current economic and industry conditions. Any changes in the projected use of proceeds will be made at the sole discretion of our board of directors.

Item 6. ***Selected Consolidated Financial Data***

The following selected consolidated financial data should be read in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and our consolidated financial statements and the related notes to those statements included elsewhere in this report. The consolidated statements of operations data for the years ended December 31, 2004, 2005 and 2006 and the balance sheet data as of December 31, 2005 and 2006 are derived from our audited consolidated financial statements included elsewhere in this report. The consolidated statements of operations data for the years ended December 31, 2002 and 2003 and the balance sheet data as of December 31, 2002, 2003 and 2004 are derived from our audited consolidated financial statements not included in this report. Historical results are not necessarily indicative of the results to be expected in the future, and the results for the years presented should not be considered indicative of our future results of operations.

	For The Years Ended December 31, 2006	2005	2004	2003	2002
Consolidated Statement of Operations:					
Revenues	$ 6,716,360	$ 7,975,990	$ 5,825,072	$ 2,452,648	$ 21,659
Lease operating expense	1,602,932	878,176	780,237	582,889	19,955
General and administrative	2,347,447	1,551,747	1,963,649	1,259,269	856,491
Net profits expense	632,708	856,837	579,590	225,869	
Impairment expense	38,849		2,038,422	473,496	
Depreciation and depletion expense	2,406,612	1,832,693	2,077,004	798,555	5,138
Earnings (loss) from operations	(312,188)	2,856,537	(1,613,830)	(887,430)	(859,925)
Net income (loss)	(482,406)	2,640,471	(2,077,615)	(1,684,692)	(1,284,480)
Net income (loss) attributable to common shareholders	$ (1,011,806)	$ 2,111,074	$ (2,606,978)	$ (1,943,565)	$ (1,299,700)
Earnings (Loss) per Share:					
Basic	$ (0.04)	$ 0.10	$ (0.14)	$ (0.12)	$ (0.09)
Diluted	$ (0.04)	$ 0.09	$ (0.14)	$ (0.12)	$ (0.09)
Weighted Average Number of Common Shares Outstanding:					
Basic	25,990,868	20,890,841	18,901,607	16,497,898	14,465,177
Diluted	25,990,868	24,001,888	18,901,607	16,497,898	14,465,177
Production Data:					
Natural gas (Mcf)	2,229,059	1,991,105	2,316,895	1,217,327	14,737
Natural gas (Mcfd)	6,107	5,455	6,348	3,335	40
Production Data reduced by net profits interests:					
Natural gas (Mcf)	1,950,427	1,742,217	2,027,283	1,065,161	12,895
Natural gas (Mcfd)	5,344	4,773	5,554	2,918	35
Average Sales Prices:					
Natural gas (per Mcf)	$ 3.01	$ 4.01	$ 2.51	$ 2.01	$ 1.47

	For the Years Ended December 31, 2006	2005	2004	2003	2002
Balance Sheet Information:					
Current assets	$ 2,366,081	$ 1,718,893	$ 1,579,388	$ 2,967,626	$ 832,255
Total assets	39,061,478	25,014,826	22,771,411	18,875,981	13,652,187
Current liabilities	3,604,342	3,574,466	7,582,377	1,471,248	2,383,725
Long-term liabilities	48,842	26,641	24,705	5,242,554	4,853,409
Redeemable Series AA Preferred Stock	5,924,068	5,924,068	5,924,068	5,924,068	768,283
Deficit	$ (10,393,985)	$ (9,382,179)	$ (11,493,253)	$ (8,886,275)	$ (6,942,710)

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

The following discussion and analysis should be read in conjunction with accompanying financial statements and related notes included elsewhere in this report. It contains forward looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for natural gas and oil, economic and competitive conditions, regulatory changes, estimates of proved reserves, potential failure to achieve production from development drilling projects, capital expenditures and other uncertainties, as well as those factors discussed below and elsewhere in this report, particularly in Risk Factors and Cautionary Notes Regarding Forward Looking Statements , all of which are difficult to predict and which expressly qualify all subsequent oral and written forward-looking statements attributable to us or persons acting on our behalf. In light of these risks, uncertainties and assumptions, the forward looking events discussed may not occur. We do not have any intention or obligation to update forward-looking statements included in this report after the date of this report, except as required by law.

Overview

We are an oil and gas company in the business of exploring and developing oil and natural gas reserves on a worldwide basis. Since inception, we have conducted leasehold acquisition, exploration and drilling activities on our North American, Australian and Indonesian prospects. These projects currently encompass approximately 1.56 million gross (396,080 net) acres, consisting of mineral leases, production sharing contract and exploration permits that give us the right to explore for, develop and produce oil and natural gas. Most of these properties are in the exploration, appraisal or development drilling phase and have not begun to produce revenue from the sale of oil and natural gas. Excluding minor interest and dividend income, our only significant cash inflows until 2003 were the recovery of capital invested in projects through sale or other divestiture of interests in oil and gas prospects to industry partners.

Since 2003, substantially all of our revenue has been generated from natural gas sales derived from the Magness #1 well in the Madisonville Field in East Texas under spot gas purchase contracts at market prices. Natural gas sales from the Madisonville Field are expected to account for substantially all of our revenues for 2007. We expect the majority of our capital expenditures in 2007 to be the costs of drilling and completing wells in the Madisonville Field.

	For The Years Ended December 31, 2006	2005	2004
Consolidated Statement of Operations:			
Revenues	$ 6,716,360	$ 7,975,990	$ 5,825,072
Lease operating expense	1,602,932	878,176	780,237
General and administrative	2,347,447	1,551,747	1,963,649
Net profits expense	632,708	856,837	579,590
Impairment expense	38,849		2,038,422
Depreciation and depletion expense	2,406,612	1,832,693	2,077,004
Earnings (loss) from operations	(312,188)	2,856,537	(1,613,830)
Net income (loss)	(482,406)	2,640,471	(2,077,615)
Net income (loss) attributable to common shareholders	$ (1,011,806)	$ 2,111,074	$ (2,606,978)

Revenue and Operating Trends in 2007

As discussed in Properties Texas Madisonville Project, in order to produce the gas reserves from the Rodessa Formation, we developed an onsite plan to treat and remove impurities from the Madisonville Project natural gas in order to meet pipeline-quality specifications. In 2003, the construction and installation of a natural gas treatment plant with a designed capacity of 18 MMcf/d and associated pipeline and gathering facilities were completed. The treatment plant and associated pipeline and gathering facilities are owned by an unaffiliated third party.

The natural gas plant is currently treating approximately 16.5 MMcf/d of inlet natural gas from our Magness and Fannin Wells. These wells accounted for approximately 99% of our revenue in 2006.

In 2005 we secured a commitment from MGP to install and make operational additional treating facilities capable of treating 50 MMcf/d, which combined with the capacity of the current in-service treating facilities will represent a total designed treating capacity of 68 MMcf/d for the Madisonville treatment plant. Our agreement with MGP provides that the newly installed gas treatment facilities will be 100% electrically driven when the treatment capacity is expanded. Currently, the existing in-service treatment plant utilizes some of the natural gas produced and delivered from our well(s). The conversion to 100% electricity on the expanded portion of the treatment plant is expected to reduce shrinkage of our natural gas that occurs in the treating process.

Representatives of MGP have indicated that they expect the full expansion of the treatment plant to 68 MMcf/d capacity can be in place and operational by the second quarter of 2007.

Upon completion of the plant expansion, we expect to produce our Fannin Well at a higher rate as the well rate has previously been restricted due to capacity limitations in the gas treatment plant. We also expect to commence production from our Mitchell Well, which is currently shut-in awaiting the plant expansion. In addition, later in 2007 we expect to fracture stimulate the Wilson Well, and provided such stimulation is successful, we will place the Wilson Well on production.

In addition, our contract with MGP provides that for the first 18,000 Mcf/d of gas measured and delivered to the inlet flange of the gas treatment plant, we will pay MGP a treating fee of $1.50 per Mcf (this fee is presently $1.55 per Mcf adjusted for inflation). For any gas volumes in excess of 18,000 Mcf/d of gas delivered to the inlet flange of the gas treatment plant, the treating fee we pay to MGP is reduced from $1.50 to $1.10 per Mcf ($1.14 per Mcf Adjusted for inflation). We record our revenues net of these treating fees. Thus, if we are able to increase our inlet production volumes over 18 MMcf/d on a sustained basis, we expect to experience a disproportionately higher increase in revenue due to lower average treating fees per Mcf.

While there can be no assurance, the (i) higher production rates from our wells, combined with the (ii) potentially reduced shrinkage rates and (iii) lower average treating fees per Mcf, may result in higher net production and increased revenue during 2007 as compared to 2006 and prior periods.

Industry Overview for the Year Ended December 31, 2006

The year 2006 saw softening natural gas prices. The Houston Ship Channel price, the index price prevailing in the locale of our Madisonville Project in Madison County, Texas, as quoted in Gas Daily as of December 29, 2006, was $5.40 versus $7.80 as of December 31, 2005. In the year of 2005, the natural gas prices were strong as a result of hurricane related supply disruptions and generally tight supplies of natural gas in the United States. Availability of capital, particularly equity capital for junior oil and natural gas companies, continued to show improvement in 2006. As a result of the initial public offering in Canada in March 2006, we were able to drill two wells in our Madisonville Project during 2006.

Company Overview in 2006

Our net loss after taxes for the year ended December 31, 2006 was $1,011,806. From our inception, through mid-2003, we only received nominal revenues from our oil and natural gas activities, while incurring substantial acquisition and exploration costs and overhead expenses which have resulted in an accumulated deficit through December 31, 2006 of $10,393,985. Commencing in May 2003, we placed our Madisonville Project into production. Substantially all of our oil and natural gas sales for the year ended December 31, 2006 were derived from our Madisonville Project, from two producing wells, the UMC Ruby Magness #1 well (the Magness Well) and the Angela Farris Fannin #1 well (the Fannin Well).

Comparison of Results of Operations for the twelve ended December 31, 2006 and 2005

During the twelve months ended December 31, 2006, we had oil and natural gas revenues of $6,716,360. Our net production was 2,229,059 thousand cubic feet (Mcf) of natural gas at an average price of $3.01 per Mcf. During the twelve months ended December 31, 2005, we had oil and natural gas revenues of $7,975,990. Our net production for the twelve months ended December 31, 2005 was 1,991,105 Mcf at an average price of $4.01 per Mcf. Revenues decreased in the twelve months ended December 31, 2006 as compared to the prior year period due to lower gas prices in spite of 12%

higher production volumes. Prices were approximately 25% lower for the twelve months ended December 31, 2006 versus the same period in 2005.

During the twelve months ended December 31, 2006, we incurred lease operating expenses of $1,602,932. Our average lifting cost for the 2006 period was $0.72 per Mcf. During the twelve months ended December 31, 2005, we incurred lease operating expenses of $878,176. Our average lifting cost for the 2005 period was $0.44 per Mcf. The higher average lifting cost in 2006 was due to higher lease operating costs and production taxes attributable to the Fannin #1 well. The primary reason for the increase in average lifting cost per Mcf were increases in production costs related to the Fannin #1 well which was placed in production in March 2006. The production for the Magness and the Fannin wells is at present limited to the current treatment plant s capacity of up to 18,000 Mcf/d. Therefore, the production from the Fannin #1 and the Magness #1 wells is limited to a rate that is below the combined productive flow capability of the wells. A majority of the lease operating costs are fixed costs such as chemical treatments for the wells, insurance, ad valorem tax, and salaries paid to the field personnel. During the twelve months ended December 31, 2006, the total lease operating costs for the Magness #1 well were $752,924 versus $878,176 in the same period of 2005. The net production of the Magness #1 well was 1,155,840 Mcf for the twelve months ended December 31, 2006 compared to 1,991,105 Mcf in same period of 2005. Some of the production decrease is attributable to natural declines and some of the decrease is attributable to the fact that the Magness #1 well shared the treating capacity of the treatment plant with the Faninn #1 well in 2006 whereas in the comparable 2005 period it did not. As a result, the average lifting cost for Magness #1 well was $0.65 per Mcf for the twelve months ended December 31, 2006 versus $0.44 per Mcf in the same period of 2005. The Fannin #1 well s average lifting cost was higher than the Magness #1 well due mainly to the severance tax of $230,600 which was incurred on the Fannin #1 well for the twelve months ended December 31, 2006. The Magness #1 well is exempt from the severance tax. The average lifting cost for the Fannin #1 well was $0.79 per Mcf for the twelve months ended December 31, 2006.

During the twelve months ended December 31, 2006, we incurred net profits interest expense of $632,708 associated with the Magness and Fannin wells as compared to $856,837 during the twelve months ended December 31, 2005. The 26% decrease resulted from lower net revenues from the wells in the twelve months ended December 31, 2006 versus 2005. The net profits interest is 12.5% of the net operating profits from our Magness and Fannin wells.

General and administrative expenses for the twelve months ended December 31, 2006 were $2,347,447 compared to $1,551,747 for the twelve months ended December 31, 2005. This represents a $795,700 increase over the prior year period due to primarily to:

1. $198,000 of stock based compensation,

2. a $265,000 increase in directors and officers liability insurance,

3. $48,000 in filing fees related to our public listing on the Toronto Stock Exchange; and

4. $285,000 in legal, audit, printing and filing fees associated with the S-1 registration statement which was prepared for the resale of some of our common stock.

For the year ended December 31, 2006, impairment expense was incurred in amount of $38,849 as compared to $0 in the same period of 2005. The 2006 impairment write-downs were associated with the Canadian cost pool. The remaining costs of drilling a dry hole in Canada of $38,849 were expensed in 2006.

Depreciation, depletion and amortization expense (DD&A) for the twelve months ended December 31, 2006 was $2,406,612 as compared to $1,832,693 in the same period of 2005, which amounts represent amortization of the U.S. full cost pool for the twelve months ended December 31, 2006 and 2005, respectively. The increase was due to higher net production in the twelve months period of 2006 and an increase in the amount of capitalized cost in the U.S. full cost pool.

Loss from operations totaled $312,188 for the twelve months ended December 31, 2006 as compared to income from operations of $2,856,537 for the twelve months ended December 31, 2005. The decrease in the income from operations was due primarily to lower gas prices, higher lease operating expenses, and higher G&A expenses.

Other income for the twelve months ended December 31, 2006 and 2005 consisted of interest income in the amount of $198,050 and $18,969, respectively. The reason for the increased interest income was higher average cash and cash equivalent balances during 2006 period as compared to 2005 period resulting from net proceeds received from common stock offerings completed by us in 2006.

During the twelve months ended December 31, 2006 and 2005, we incurred interest expense of $306,682 and $217,768, respectively. The higher interest expense in the current year period was due to $194,691 in expense related to the amortization of debt issuance costs in connection with a debt financing in January 2006 consisting of: (i) the fair market value assigned to common stock warrants issued, and (ii) a loan origination fee paid.

Net loss before taxes for the twelve months ended December 31, 2006 was $420,820 as compared to net income before taxes of $2,657,738 for the twelve months ended December 31, 2005. The loss incurred during 2006 was primarily due to lower gas income, higher lease operating expenses as well as higher general and administrative costs.

Income tax expense for the twelve months ended December 31, 2006 was $61,586 compared to $17,267 in the same period of 2005. The increased income tax expense was due to 2005 alternative minimum tax paid in 2006.

Industry Overview for the Year Ended December 31, 2005

The year 2005 saw continued strong natural gas prices as a result of hurricane related supply disruptions and generally tight supplies of natural gas in the United States. The Houston Ship Channel price, the index price prevailing in the locale of our Madisonville Project in Madison County, Texas, as quoted in Gas Daily as of December 31, 2005, was $7.80 versus $5.82 as of December 31, 2004. Availability of capital, particularly equity capital for junior oil and natural gas companies, continued to show improvement in 2005, and in 2005, we raised $4,727,824 net of issuance costs through equity financing transactions. As a result, and through the sale of one of our Indonesian property interests, we were able to repay our indebtedness of $1.7 million to various creditors and improve our capital position during 2005.

During 2005, we received a weighted average net price of $4.01 per mcf of gas sold. As further discussed under Properties Texas Madisonville Project , we receive revenue for our gas sales net of certain costs to treat and transport the gas. The weighted average gross price during 2005, prior to the deduction of the treating and transportation costs, was $6.81. This compares to $7.80 which was the price prevailing on the last day of 2005.

Company Overview in 2005

Our net income after taxes for the year ended December 31, 2005 was $2,640,471. From our inception to 2003, we only received nominal revenues from our oil and natural gas activities, while incurring substantial acquisition and exploration costs and overhead expenses which resulted in our sustaining an accumulated deficit through December 31, 2005 of $9,382,179. We placed our Madisonville Project into production in May 2003. Substantially all of our oil and natural gas sales for the year ended December 31, 2005 were derived from our Madisonville Project, from one producing well, the Magness #1 well.

Comparison of Results of Operations for the twelve months ended December 31, 2005 and 2004

During the year ended December 31, 2005, we had oil and natural gas revenues of $7,975,990. Our net production was 1,991,105 thousand cubic feet (Mcf) of natural gas at an average price of $4.01 per Mcf. During the year ended December 31, 2004, we had oil and natural gas revenues of $5,825,072. Our net production for the year ended December 31, 2004 was 2,316,895 Mcf at an average price of $2.51 per Mcf. Revenues increased in the year ended December 31, 2005 as compared to the prior period due to higher gas prices. This is because average prices in 2005 were 60% higher than 2004, more than offsetting the 14% drop in production from 2004 to 2005. Production was lower due to normal declines associated with the production of reserves from the Magness #1 well.

During the year ended December 31, 2005, we incurred lease operating expenses of $878,176. Our average lifting cost for this period was $0.44 per Mcf. During the year ended December 31, 2004, we incurred lease operating expenses of $780,237. Our average lifting cost for this period was $0.34 per Mcf. The primary reasons for the increase in average lifting cost per Mcf were increases in costs and lower net production. The increase in lease operating costs was due primarily to higher insurance premiums, approximately $40,000, and higher costs of chemical treatments, approximately $60,000 associated with the Magness #1 well.

During the year ended December 31, 2005, we incurred net profits interest expense of $856,837 associated with the Magness Well compared to $579,590 during the year ended December 31, 2004. The increase resulted from higher revenues associated with the Magness Well in 2005 versus 2004.

General and administrative expenses for the year ended December 31, 2005 were $1,551,747 compared to $1,963,649 for the year ended December 31, 2004. This represents a $411,902 decrease over the prior year period due to stock based compensation incurred in 2004. During 2004 we issued 500,000 shares of our common stock for cash proceeds of $500,000 in connection with the exercise of stock options by an officer and director. Concurrent with the exercise of stock options, the officer sold 117,647 shares of common stock to us at the estimated fair market value price prevailing at that time of $4.25 per share. We recorded compensation expense of $500,000 in connection with the purchase of stock.

Depreciation, depletion and amortization expense for the year ended December 31, 2005 was $1,832,693 compared to $2,077,004 in the year ended December 31, 2004, which amounts represent amortization of the U.S. full cost pool for the year ended December 31, 2005 and 2004, respectively. The decrease was due to lower net production in 2005 as well as an upward revision in net proved reserve estimates during the year.

For the year ended December 31, 2005, no impairment expense was incurred as compared to $2,038,422 for the year ended December 31, 2004. The 2004 impairment write-downs were associated with the Canadian and Australian cost pools. We expensed the costs of drilling dry holes in those areas during 2004 while no such costs associated with unsuccessful wells were incurred in 2005.

Earnings from operations totaled $2,856,537 for the year ended December 31, 2005 compared to a loss of $1,613,830 for the year ended December 31, 2004. The increase in the earnings from operations was due primarily to higher revenues associated with the Magness Well.

Other income for the year ended December 31, 2005 and 2004 consisted of interest income in the amount of $18,969 and $6,548, respectively. The reason for the increase was higher average cash and cash equivalents balances for the 2005 period as compared to 2004.

During the year ended December 31, 2005 and 2004, we incurred interest expense of $217,768 and $402,958, respectively. The lower interest expense in the current year period was due to lower average debt levels. In March 2004, we incurred a cash finders fee of $67,375 to a director associated with the negotiation of a reduction in debt through the conversion of $1,347,500 of long-term debt to equity.

Net income after taxes for the year ended December 31, 2005 was $2,640,471 compared to net loss of $2,077,615 for the year ended December 31, 2004. The increase in net income was primarily due to higher revenues associated with the Magness Well and the impairments expense recorded in the previous period.

Industry Overview for the Year Ended December 31, 2004

The year 2004 saw continued strong natural gas prices as a result of tight supplies of natural gas in the United States. The Houston Ship Channel price, the index price prevailing in the locale of the Madisonville Project, as quoted in Gas Daily as of December 30, 2004, was $5.82 versus $5.76 as of December 31, 2003. Availability of capital, particularly equity capital for junior oil and natural gas companies, continued to show improvement in 2004 and in 2004, we raised $3,479,899 net of issuance costs through equity financing transactions.

Revenue Trend in 2004

The results of operations for the year ended 2004 reflected a full year of production revenues from the Madisonville Project where we had one well on production. Substantially all of our oil and natural gas sales for the year ended December 31, 2004 were derived from our Madisonville Project in Madison County, Texas.

Comparison of Results of Operations for the Years ended December 31, 2004 and 2003

During the year ended December 31, 2004, we had oil and natural gas revenues of $5,825,072. Our net production was 2,316,895 Mcf at an average price of $2.51 per Mcf. During the year ended December 31, 2003, we had oil and natural gas revenues of $2,452,648. Our net production was 1,217,327 Mcf at an average price of $2.01 per Mcf for 2003.

During the year ended December 31, 2004, we incurred lease operating expenses of $780,237. Our average lifting cost for this period was $0.34 per Mcf. During the year ended December 31, 2003, we incurred lease operating expenses of $582,889. Our average lifting cost for this period was $0.48 per Mcf. The reason for the significant decrease in average lifting cost per Mcf was that the Magness Well experienced significantly higher production volumes in 2004 versus 2003.

During the year ended December 31, 2004, we incurred net profits interest expense of $579,590 associated with the Magness Well compared to $225,869 in 2003. This was due to higher revenues associated with the Magness Well in 2004 versus 2003.

General and administrative expenses for the year ended December 31, 2004 were $1,963,649 compared to $1,259,269 for 2003. This represents a $704,380 or a 56% increase over the prior year period. The primary reason for the increase was a $500,000 non-cash charge associated with stock-based compensation. During 2004 we issued 500,000 shares of our common stock for cash proceeds of $500,000 in connection with the exercise of stock options by an officer and director.

Concurrent with the exercise of stock options, the officer sold 117,647 shares of common stock to us at the estimated fair market value price at that time of $4.25 per share. We recorded compensation expense of $500,000 in connection with the purchase of stock. The balance of the increase was due to additional employees and salary increases.

Depreciation, depletion and amortization expense for the year ended December 31, 2004 was $2,077,004 compared to $798,555 for 2003, substantially all of which represents amortization of the U.S. full cost pool for the respective periods. The increase was due to higher depletion expense associated with the Magness Well due to higher production in 2004 versus 2003.

For the years ended December 31, 2004 and 2003, we incurred impairment expense of $2,038,422 and $473,496, respectively. The 2004 impairment write-downs were associated with the Canadian and Australian cost pools while the 2003 impairment write-down was due to the expiration of Permit #386 in Australia. We expensed the costs of drilling dry holes in Canada and Australia during 2004. The impairment charge in 2003 relates to the costs capitalized in connection with an exploration permit which expired during 2003.

Loss from operations totaled $1,613,830 for the year ended December 31, 2004 compared to a loss of $887,430 for 2003. The increase in the loss from operations was due to higher impairments and depletion expenses.

Other income for the year ended December 31, 2004 and 2003 consisted of interest income in the amount of $6,548 and $4,769, respectively. The reason for the increase was higher average cash and cash equivalents balances for the 2004 period as compared to 2003.

During the years ended December 31, 2004 and 2003, we incurred interest expense of $402,958 and $802,031, respectively. The higher interest expense in the prior year period was due to short-term borrowings which were incurred to drill and complete the injection well and equipment for production of the Magness Well. In 2004, we incurred debt conversion expense of $67,375 associated with the conversion of $1,347,500 of long-term debt to equity.

Net loss after taxes for the year ended December 31, 2004 was $2,077,615 compared to a loss of $1,684,692 for the year ended December 31, 2003. The increase in net loss was primarily due to higher impairments and depletion.

Recent Developments

On September 29, 2006, we sold to CNPC 70% of our shareholding in C-G Bengara and our interest in the Bengara Block, reducing our interest from 40% to 12%. CNPC is a wholly owned subsidiary of CNPC (Hong Kong) Ltd. who is party to the agreements as guarantor. CNPC (Hong Kong) Ltd. is a publicly held company based in Hong Kong and its shares trade on the Hong Kong Stock Exchange under the listing number 0135.HK. CNPC (Hong Kong) Ltd. is a 52% owned subsidiary of the China National Petroleum Company based in Beijing, PRC. See Properties Description of Properties Indonesia.

During 2006, our wholly-owned subsidiary, Redwood Energy Production, L.P. (**Redwood LP**), was a defendant in two lawsuits, titled the Miller Lawsuit and Redwood vs. George Mejlaender. To avoid the costs of continued litigation, Redwood LP, the Miller plaintiffs and the Mejlaender plaintiffs, through mediation, entered into a binding settlement agreement on June 1, 2006 to resolve all of their disputes. Under the terms of the settlement, Redwood LP paid the plaintiffs $1,100,000 in cash upon the closing of the settlement, executed a 6% promissory note in favor of the Miller and Mejlaender plaintiffs with a December 29, 2006 maturity date in the amount of $900,000 secured by Redwood LP s interest in the Magness Well, and assigned the plaintiffs overriding royalty interests of 2% in the Magness Well, 2% in the Fannin Well, 0.75% in the Wilson Well, and agreed to assign 0.5%, 0.3% and 0.2% in the first, second and third wells, respectively, in the event these wells are drilled and completed by Redwood LP below the Rodessa-Sligo Interval. The plaintiffs have assigned to Redwood LP any and all ownership interests they may have had in the

Madisonville Prospect below the top of the Rodessa-Sligo Interval and conveyed all of their overriding royalty interests in the Madisonville Prospect in the Rodessa-Sligo Interval and below. The combined $2.0 million has been recorded to evaluated oil and gas properties. On December 28, 2006, we paid the 6% promissory note, plus accrued interest, in full.

In February 2007, we borrowed $900,000 pursuant to three promissory notes bearing interest at 8% per annum. The notes mature on October 31, 2007. In connection with these notes, we paid loan origination fees totaling $27,000 and issued three year warrants exercisable to to purchase 45,000 shares of our common stock at $3.50 per share which expire in February 2009.

In February 2007, we received an extension of the maturity date of our promissory note payable to Pine Hill Capital, LLC to October 31, 2007. In connection with the extension, we paid a loan extension fee of $30,000 and granted a three-year warrant to purchase 50,000 shares of our common stock at $3.50 per share. Under our agreement with Pine Hill, we agreed to pay the entire remaining principal balance of our note, which is $1,000,000 as of March 30, 2007, plus accrued interest, on October 31, 2007. If we do not repay the note by October 31, 2007, or receive an extension, continuing the terms of our original loan agreement with Pinehill, we are required to dedicate 5% of our net cash flow from the Madisonville Project located in Madison County, Texas, toward the unpaid principal and all accrued & unpaid interest on the note, until all such amounts are paid-in-full. Net cash flow means our gross revenues, less royalties, production taxes & net profits interest expense.

In February 2007, Stuart J. Doshi, President and CEO, loaned $100,000 to us pursuant to a promissory note bearing interest at 8% per annum, payable upon demand. We repaid the note plus accrued interest on March 28, 2007.

On June 7, 2006, we loaned $1,000,000 to G. Carter Sednaoui, a 5% shareholder, evidenced by a full-recourse short-term promissory note payable to us with an original maturity date of March 31, 2007. On March 30, 2007, we extended the maturity date of the note to June 30, 2007.

On March 28, 2007, all 1,890,710 of our outstanding shares of our Series AA Stock, automatically converted into 1,890,710 shares of our common stock, no par value per share. Under our Amended and Restated Articles of Incorporation, and as more fully described in Note 7 to our Consolidated Financial Statements, the Series AA stock automatically converts into common shares on a one-for-one share basis effective the first trading day after the reported high selling price for our common shares is at least $5.25 per share for any consecutive ten trading days, which condition was met on March 27, 2007. As a result of the conversion of our Series AA stock to common stock on March 28, 2007, dividends on the Series AA Stock ceased accruing on December 31, 2006. In 2006, dividends paid on the Series AA Stock totaled $529,400.

Liquidity and Capital Resources

We had a working deficit of $1,238,261 versus $1,855,573 at December 31, 2006 and December 31, 2005, respectively. Our working capital increased during year ended December 31, 2006 due primarily to initial public offering (IPO) in Canada in March 2006, which consisted of 3,730,021 common shares from our treasury at an issue price of $3.50 per common share and 519,500 common shares issued on a flow-through basis under the *Income Tax Act* of Canada at an issue price of $3.85 per common share for aggregate gross proceeds of $15,055,149. We utilized most of the net proceeds of the offering to fund drilling of wells in the Madisonville Project.

We have historically financed our business activities through December 31, 2006 principally through issuances of common shares, promissory notes and Common Share purchase warrants in private placements and more recently, an initial public offering. These financings are summarized as follows:

	Years Ended December 31, 2006	December 31, 2005	December 31, 2004
Proceeds from sale of Common Shares and warrant exercises, net	$ 16,717,604	$ 4,727,824	$ 3,479,899
Payment on preferred dividends	(529,400)	(529,397)	(529,363)
Repayments of promissory notes		(4,781,807)	
Proceeds from promissory notes	1,900,000		2,075,000
Payment of loan fee	(30,000)		(1,158,569)
Repayment of promissory notes	(900,000)		
Deferred offering costs	(1,213,789)	(730,906)	(150,255.00)
Purchase of treasury stocks		(592,435)	
Net cash provided by financing activities	$ 15,944,415	$ (1,906,721)	$ 3,716,712

The net proceeds of our equity financings have been primarily invested in oil and natural gas properties totaling $16,721,944, $5,602,741 and $9,171,589 for the years ended December 31, 2006, 2005 and 2004, respectively.

Our cash balance at December 31, 2006 was $734,561 compared to a cash balance of $914,826 at December 31, 2005. The change in our cash balance is summarized as follows:

Cash balance at December 31, 2005	$ 914,826
Sources of cash:	
Cash provided by operating activities	1,601,869
Cash provided by financing activities	15,944,415
Total sources of cash including cash on hand	18,461,110
Uses of cash:	
Cash used in investing activities:	
Oil and natural gas property expenditures	(16,721,944)
Furniture, fixtures and equipment	(4,605)
(Increase) in related party notes receivable	(1,000,000)
Total uses of cash	(17,726,549)
Cash balance at December 31, 2006	$ 734,561

Our current cash and cash equivalents and anticipated cash flow from operations may not be sufficient to meet our working capital, capital expenditures and growth strategy requirements for the foreseeable future. See Outlook for 2007 for a description of our expected capital expenditures for 2007. If we are unable to generate revenues necessary to finance our operations over the long-term, we may have to seek additional capital through the sale of our equity or borrowing. As noted in Recent Developments, we periodically borrow funds pursuant to short term promissory notes to finance our activities.

Contractual Obligations

A summary of our contractual obligations as of December 31, 2006 is provided in the following table:

	Payments Due By Period (6)				
Contractual Obligations at December 31, 2006	**Total**	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**
Operating lease obligations(1)	$ 168,256	$ 76,856	$ 91,400	$	$
Production sharing contract (2)	120,000	120,000			
Madisonville Field drilling obligation (3)	10,000,000		10,000,000		
Cook Inlet Alaska work program (4)	3,568,063		3,568,063		
Canadian flow-through shares (5)	2,000,075	2,000,075			
Total	$ 15,856,394	$ 2,196,931	$ 13,659,463	$	$

(1) Lease for our principal executive office located at One Maritime Plaza, Suite 700, San Francisco, CA 94111.

(2) We have work program commitments associated with our participation net to our 12% working interest in the Bengara II PSC (production sharing contract) in Indonesia. These work program commitments must be met in order to maintain the production sharing contract in effect**.**

(3) In order to facilitate the expansion of the gas treatment plant in our Madisonville Project, we are subject to a drilling commitment. The commitment, subject to events of force majeure, including, but not limited to rig availability, requires us to commence the drilling of a well sufficient to test the Smackover Formation (estimated to be encountered at approximately 18,000 feet) on or before September 30, 2008. The commitment is not discretionary. We have granted MGP a security interest in the Madisonville Field properties to secure the commitment. The security interest shall be subordinated to any third party lender in the event we secure future debt against the property. MGP granted us a security interest in the Madisonville Field Gas Treatment Plant to secure their obligation to expand the capacity of the facilities.

(4) Within three years from the date of receipt of assignment of the 100% working interest in the leases in our Cook Inlet Alaska CBM Project, we have the option to conduct a $2.5 million work program consisting of, but not limited to, a multiple test well drilling program on the leases over a three-year period, and, after completion of the work program and an evaluation of the results, to remit the final additional acreage consideration of $10 per acre for the leases estimated at approximately $1,068,000. The Cook Inlet Option provides that if we fail to pay the lease consideration when due, fail to perform the work program or otherwise default under the Cook Inlet Option, we shall forfeit our interest and reassign the leases to Pioneer with no further liability to us.

(5) It is required that we expend $2,000,075 of the proceeds realized from the Canadian offering from the issuance of 519,500 flow-through shares toward Canadian exploration expense pursuant to Canadian tax law. Canadian exploration expense generally means, but is not limited to, the drilling of exploratory wells in Canada. Pursuant to the terms of our agreement with the subscribers of the flow-through shares, we must renounce the tax deductions which would result from these expenditures and pass the deductions through to the holders of these shares. We must incur these expenditures by the end of our fiscal year ended December 31, 2007.

(6) This table does not include the liability for dismantlement, abandonment and restoration costs of oil and gas properties. Effective with the adoption of SFAS No. 143, Accounting for Asset Retirement Obligations, we recorded a separate liability for the fair value of this asset retirement obligation. See Note 2 of the Notes to Consolidated Financial Statements for further discussion.

In addition to the above future commitments, our 12% owned subsidiary, C-G Bengara, is subject to prior work commitments for the eight-year period ended December 3, 2006 requiring total expenditures of $24 million in the Indonesian contract area known as the Bengara Block. As of September 30, 2006, C-G Bengara had met approximately $6.3 million of the $24.0 million required expenditures, leaving an approximate $17.7 million shortfall. BP Migas, the applicable governing authority, has granted a deferral of the prior years commitments. On September 29, 2006, we sold to CNPC 70% of our shareholding in our C-G Bengara subsidiary and our interest in the Bengara Block, reducing our interest from 40% to 12%. Per the terms of the agreement, CNPC has deposited an $18.7 million earning obligation into a C-G Bengara account jointly controlled by CNPC, Continental and us. The funds are to be used exclusively to pay for 2007 exploration drilling in the 900,000 Bengara Block in East Kalimantan, Indonesia. The earning obligation funds of $18.7 million, together with the $6.3 million previously spent, will satisfy all of the past and future work commitments on the Bengara Block. C-G Bengara has four exploration wells planned, permitted and approved by Indonesian oil and gas regulatory authorities for drilling in 2007. C-G Bengara is now preparing plans for conducting the drilling program and expects to commence drilling activities in the second quarter of 2007.

The above amounts do not include program commitments for our Exploration Permit (EP) 408. The program commitments for EP 408 have been substantially met and require no further significant expenditures.

Other than the above commitments, the timing of most of our capital expenditures is discretionary. We have no material long-term commitments associated with our capital expenditure plans or operating agreements. Consequently, we have a significant degree of flexibility to adjust the level of such expenditures as circumstances warrant. The level of capital expenditures will vary in future periods depending on the success we experience on planned exploratory and appraisal drilling activities, natural gas and oil price conditions and other related economic and political factors. Accordingly, we have not yet prepared an estimate of capital expenditures for periods beyond 2007.

Income Taxes

As of December 31, 2006, we had net operating loss (NOL) carryforwards of approximately $22,932,000 for federal income tax purposes beginning to expire in 2010 and $10,926,000 for state income tax purposes which began to expire in 2006.

A significant change in our ownership may limit our ability to use these NOL carryforwards. Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes*, requires that the tax benefit of such net operating loss be recorded as an asset. At December 31, 2006, we had net deferred tax assets of approximately $3.7 million related to the NOL and other temporary differences. We have recorded a full valuation allowance of $3.7 million at December 31, 2006, due to uncertainties surrounding the realizability of the deferred tax asset.

Off Balance Sheet Arrangements

As of December 31, 2006, we had no off balance sheet arrangements.

Financial Instruments

We have not committed any forward sales of our natural gas and do not employ any other financial instruments.

Outlook for 2007

Depending on capital availability, we are forecasting capital spending of up to approximately $16.0 million in 2007, allocated as follows:

1. Madisonville Project, Madison County, Texas. Approximately $11.0 million will be expended in the Madisonville Field area as follows: $10,000,000 to drill a deep well location, and $1,000,000 to be utilized for land acquisition, engineering and permitting.

2. Alaska Cook Inlet Project, up to approximately $3.0 million will be expended for the drilling of pilot program wells.

3. Central Alberta Reef Project. Up to approximately $2.0 million will be expended to drill exploratory wells and acquire 3-D seismic data.

We may, in our discretion, decide to allocate resources towards other projects in addition to or in lieu of, those listed above should other opportunities arise and as circumstances warrant.

We expect commodity prices to be volatile, reflecting the current tight supply and demand fundamentals for North American natural gas and world crude oil. Political events around the world, which are difficult to predict, will continue to influence both oil and gas prices. Higher prices for oil and gas often lead to higher levels of drilling activity which in turn lead to higher costs to explore, develop and acquire oil and gas reserves due to greater competition for resources and supplies. These higher costs could affect the returns on our capital expenditures. Higher crude prices could also help keep natural gas prices high by keeping alternative fuels, such as heating oil and residual fuel, expensive.

Impact of Inflation & Changing Prices

As the following table illustrates, average sales prices of natural gas have changed in the past three years. This has led to changes in revenues and earnings from operations:

	For the Year Ended December 31,		
	2006 (1)	**2005**	**2004 (2)**
Average Sales Prices per Mcf	$ 3.01	$ 4.01	$ 2.51
Net Production Volume Mcf	2,229,059	1,991,105	2,316,895
Revenues	$ 6,716,360	$ 7,975,990	$ 5,825,072
Earnings (loss) from Operation	$ (312,188)	$ 2,856,537	$ (1,613,830)

(1) Includes $38,849 impairment expense

(2) Includes $2,038,422 impairment expense

We are highly dependent upon natural gas pricing. A material decrease in current and projected natural gas prices could impair our ability to raise additional capital on acceptable terms. Likewise, a material decrease in current and projected natural gas prices could also impact our revenues and cash flows. This could impact our ability to fund future activities.

Changing prices have had a significant impact on costs of drilling and completing wells, particularly in the Madisonville Field area where we are currently the most active. The estimated cost of drilling and completing a Rodessa formation well at approximately 12,300 feet of depth has increased from $3.0 million to $6.5 million in 2006 due to higher costs associated with tubular goods, well equipment, and day rates for drilling contracts, among other factors. These higher costs have impacted and will continue to impact our income from operations in the form of higher depletion expense.

Critical Accounting Estimates

Our consolidated financial statements have been prepared by management in accordance with U.S. GAAP.

The preparation of consolidated financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

Management believes the most critical accounting policies that may have an impact on our financial results relate to the accounting for oil and gas properties. Amortization, abandonment costs and full cost ceiling limitation write-downs are all based on numerous estimates, many of which are beyond management s control. Reserves recognition is central to much of the accounting for an oil and gas company as described below.

Significant accounting policies are contained in Note 2 to the consolidated financial statements. A summary of the unaudited supplementary oil and gas reserve information is contained in Note 12 to the consolidated financial statements.

The following discusses the accounting estimates that are critical in determining the reported financial results:

Oil and Gas Properties We follow the full cost method of accounting for oil and gas producing activities as prescribed by U.S. GAAP and, accordingly, capitalizes all costs incurred in the acquisition, exploration, and development of proved oil and gas properties, including the costs of abandoned properties, dry holes, geophysical costs, and lease rentals. All general corporate costs are expensed as incurred. In general, sales or other dispositions of oil and gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded. Amortization of evaluated oil and gas properties is computed on the units of production method based on all proved reserves on a country by country basis. Unevaluated oil and gas properties are assessed for impairment either individually or on an aggregate basis. The net capitalized costs of evaluated oil and gas properties (full cost ceiling limitation) are not to exceed their related estimated future net revenues discounted at 10%, and the lower of cost or estimated fair value of unproved properties, net of tax considerations.

Reserves We engage independent petroleum engineering consultants to evaluate our reserves. Reserves, future production profiles, and net revenues are estimated by independent professional reservoir engineering firms. While we engage qualified reservoir engineering firms, their estimates are inherently uncertain, involve numerous assumptions that may not be realized, and predict asset values that may not be indicative of the true market value of the assets evaluated. As a result of the inherent uncertainties and changing technical and economic assumptions, reserve estimates are subject to revisions that can materially impact our depletion rates, ceiling test calculations and results of operations.

Asset Retirement Obligation We provide for the estimated site restoration and abandonment costs of tangible long-lived assets using a fair value method, which approximates the cost a third party would incur in performing the tasks necessary to retire such assets. The reported liability is a discounted amount. The amount of the liability is affected by factors such as the number of wells, the timing of the expected expenditures and the discount factor. These estimates will change and the revisions could impact the amortization rates.

Stock Based Compensation We have a stock- based compensation plan that allows employees to purchase our common shares.. Option exercise prices approximate the market price for the common shares on the date the options were issued. Options granted under the plan are generally fully exercisable after five years and expire five to ten years after the grant date. Under U.S. GAAP, prior to 2006, we elected not to expense compensation cost for stock-based employee compensation at fair value but did disclose the impact of the fair value accounting of employee stock options in Note 2 to the annual audited consolidated financial statements. We adopted Statement of Financial Accounting Standards No. 123(R) (Statement 123R) on January 1, 2006, which is the beginning of our first interim period following the effective date of Statement 123R. As noted above, we previously disclosed the impact of, but did not expense stock-based employee compensation in accordance with Accounting Principal Board Opinion 25. We have applied the modified prospective method of adoption, and accordingly, the financial statements for our prior interim periods and fiscal years will not reflect any restated amounts. We have recorded $201,335 of stock-based employee compensation for the twelve months ended December 31, 2006 in connection with the portion of previously granted employee stock options that vest on or after January 1, 2006. The impact of the fair value accounting of employee stock options is estimated on the date of grant using the Black-Scholes option pricing model with assumptions for: risk free interest rates, expected dividend yields, expected life of the options from the date of grant, and expected volatility.

Risks and Uncertainties

There are a number of risks that face participants in the U.S., Canadian and international oil and natural gas industry, including a number of risks that face us in particular. Accordingly, there are risks involved in an ownership of our securities. See Risk Factors for a description of the principal risks faced by us.

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

We are exposed to market risks arising from fluctuating prices of crude oil, natural gas and interest rates as discussed below.

Commodity Risk. Our major commodity price risk exposure is to the prices received for our natural gas production. Realized commodity prices received for our production are the spot prices applicable to natural gas in the East Texas region. Prices received for natural gas are volatile and unpredictable and are beyond our control. For the year ended December 31, 2006, a 10% change in the prices received for natural gas production would have had an approximate $800,000 impact on our revenues.

Currency Translation Risk. Because our revenues and expenses are primarily in U.S. dollars, we have little exposure to currency translation risk, and, therefore, we have no plans in the foreseeable future to implement hedges or financial instruments to manage international currency changes.

Hedging. We did not enter into any hedging transactions during the years ended December 31 2006, 2005 and 2004.

Item 8. ***Financial Statements and Supplementary Data***

The reports of our independent registered public accounting firms and our consolidated financial statements and supplemental information required to be filed under Item 8 of Form 10-K are presented beginning on Page F-1 of this Form 10-K.

Item 9. ***Changes in and Disagreements With Accountants on Accounting and Financial Disclosure***

None.

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

Management s Conclusion on the Effectiveness of Disclosure Controls and Procedures

Our Chief Executive Officer and the Chief Financial Officer performed an evaluation of our disclosure controls and procedures, which have been designed to permit us to effectively identify and timely disclose important information. They concluded that our disclosure controls and procedures were effective as of December 31, 2006 to provide reasonable assurance that the information required to be disclosed in our reports filed under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC, and that such information is accumulated and communicated to our management including our Chief Executive Officer and our Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures. While our disclosure controls and procedures provide reasonable assurance that the appropriate information will be available on timely basis, this assurance is subject to limitations inherent in any control system, no matter how well it may be designed or administered.

Changes in Internal Control over Financial Reporting

There was no change in our internal control over financial reporting during the quarter ended December 31, 2006, that our Chief Executive Officer and Chief Financial Officer concluded materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

This annual report does not include a report of management s assessment regarding internal control over financial reporting or an attestation report of the Company s registered public accounting firm due to a transition period established by rules of the Securities and Exchange Commission for newly public companies.

Item 9B. ***Other Information***

None.

PART III

Item 10. ***Directors and Executive Officers of the Registrant***

The information required by this item is incorporated by reference from our definitive proxy statement.

Item 11. ***Executive Compensation***

The information required by this item is incorporated by reference from our definitive proxy statement.

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

The information required by this item is incorporated by reference from our definitive proxy statement.

Item 13. ***Certain Relationships and Related Transactions***

The information required by this item is incorporated by reference from our definitive proxy statement.

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

The information required by this item is incorporated by reference from our definitive proxy statement.

PART IV

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

1. The financial statements listed in the Index to Consolidated Financial Statements at page F-1 are filed as part of this report.

2. All other schedules are omitted because they are not applicable, not required or the required information is included in the consolidated financial statements or related notes.

3. Exhibits included or incorporated herein. See Exhibit Index.

GLOSSARY OF OIL AND NATURAL GAS TERMS

In this report, unless the context otherwise requires, the following terms shall have the indicated meanings. A reference to an agreement means the agreement as it may be amended, supplemented or restated from time to time.

1933 Act means the United States *Securities Act* of 1933, as amended.

Bengara II PSC means the PSC dated December 4, 1997 between C-G Bengara and Pertamina.

Bengara Block means the contract area in the Indonesian province of East Kalimantan designated as the Bengara (II) PSC Block.

BP Migas means Badan Pelaksana Minyak Dan Gas Muni, a new executive board established by the government of Indonesia in 2002 for oil and gas upstream operations and an implementing body created to assume the role of Pertamina s regulatory functions and responsibilities in managing oil and gas contractors.

CBM means coal bed methane, which is methane found in coal seams. It is produced by non-traditional means, and therefore, while it is sold and used the same as traditional natural gas, its production is different. CBM is generated either from a biological process as a result of microbial action or from a thermal process as a result of increasing heat with depth of the coal. Often a coal seam is saturated with water, with methane held in the coal by water pressure.

C-G Bengara means Continental-GeoPetro (Bengara II) Ltd., a British Virgin Islands corporation owned 12% by GeoPetro.

CG Xploration means CG Xploration Inc., a Delaware corporation owned 50% by GeoPetro.

CNPC means CNPCHK (Indonesia) Limited. CNPC is a wholly owned subsidiary of CNPC (Hong Kong) Limited, a publicly held company based in Hong Kong where its shares trade on the Hong Kong Stock Exchange under the listing number 0135.HK.

Company or **GeoPetro** means GeoPetro Resources Company, a corporation incorporated under the laws of the State of California and its wholly-owned subsidiaries.

Condensate means a low-density, high-API gravity liquid hydrocarbon product that is generally produced in association with natural gas. Condensate is mainly composed of propane, butane, pentane and heavier hydrocarbon fractions.

Continental means Continental Energy Corporation.

Cook Inlet Option means the option granted to GeoPetro by Pioneer to acquire a 100% working interest (81% net revenue interest) in approximately 122,000 acres in Cook Inlet, near Anchorage, Alaska.

CRA means the Canada Revenue Agency.

Earning Obligation means $18.7 million paid by CNPC into a special joint venture account at a Hong Kong international bank, which funds are under joint signature control of CNPC, ourselves and Continental, and will be expended to pay for 2007 exploration drilling in the Bengara II PSC area.

EIA means the United States Energy Information Administration.

EP 408 means the approximately 201,000 gross (52,675 net) acre permit area including the Whicher Range gas field in the South Perth basin of Western Australia designated as Exploration Permit 408.

Evaluated Properties means those properties that are producing oil or gas or on which, based on known geological and engineering data, oil and gas reserves are reasonably certain to exist.

Fannin Well means the Angela Farris Fannin No. 1 well located at the Madisonville Field.

Farmout means an agreement whereby a third party agrees to pay for the drilling of a well on one or more of GeoPetro s properties in order to earn an interest therein with GeoPetro retaining a residual interest in such properties.

Flow-Through Share means a share of common stock issued as a flow-through share within the meaning of Canadian tax law.

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Gateway means Gateway Processing Company, a Texas corporation that has constructed pipeline facilities at the Madisonville Field.

GeoPetro Alaska means GeoPetro Alaska LLC, an Alaska limited liability company, which is a wholly-owned subsidiary of GeoPetro.

GeoPetro Canada means GeoPetro Canada Ltd., an Alberta corporation, which is a wholly-owned subsidiary of GeoPetro.

Hanover means Hanover Compression Limited Partnership, a Delaware limited partnership that has constructed and previously operated treatment facilities at the Madisonville Field.

Hanover Agreement means, collectively, the First Amended and Restated Master Agreement, dated as of September 12, 2002 among Redwood, Hanover and Gateway, as amended, providing for the processing of natural gas from the Madisonville Field, and the agreements related thereto, which agreements were in effect prior to August 2005.

LPG means liquefied petroleum gas.

Madisonville Field means the Madisonville (Rodessa) field in Madison County, Texas.

Madisonville Project means the oil and natural gas exploration, development and production project at the Madisonville Field.

Magness Well means the UMC Ruby Magness No. 1 well located at the Madisonville Field.

Makapan Gas Field means the Makapan gas field in East Kalimantan, Indonesia.

MGP means Madisonville Gas Processing, LP, a Colorado Limited Partnership that has purchased from Hanover and currently operates the treatment facilities at the Madisonville Field, and is jointly owned by JPMorgan Partners and Bear Cub Investments LLC.

MGP Agreement means, collectively, the Termination and Release Agreement, Madisonville Field Development Agreement, Gas Purchase Contract between Redwood LP as Seller, and MGP as Buyer, Escrow Agreement and Dedication Agreement, all effective as of August 1, 2005 among Redwood LP, MGP, Gateway and Gateway Pipeline Company, providing for the termination of the Hanover Agreement, the expansion of the treatment facilities and the provision of the gathering, processing, transportation and sale of natural gas from the Madisonville Field.

Mitchell Well means the Mitchell No. 1 well located at the Madisonville Field.

Pertamina means Perusahaan Pertambangan Minyak Dan Gas Bumi Negara, the previous Indonesian state-owned oil and natural gas company established in 1971 which had exclusive authority to explore, drill for, and produce oil and natural gas minerals in Indonesia. In accordance with the new Indonesian Oil and Gas Law, its corporate form has been changed to become a state-owned limited liability company established under Indonesian Company Law, and all rights and obligations of Pertamina under existing PSCs shall pass to BP Migas.

Pioneer means Pioneer Oil Company, Inc.

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

Proved developed nonproducing reserves means reserves expected to be recovered from zones behind casing in existing wells.

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

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or a conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(iii) Estimates of proved reserves do not include the following:

(A) oil that may become available from known reservoirs but is classified separately as indicated additional reserves ;

(B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;

(C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and

(D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved undeveloped reserves means reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

PSC means a production sharing contract, being a contract with Pertamina whereby Pertamina contracts with a petroleum company to explore for, develop and extract petroleum substances from a particular license area, on Pertamina s behalf, at the risk and expense of the petroleum company, in exchange for a share of the production.

Redwood means Redwood Energy Company, a Texas corporation, which is a wholly-owned subsidiary of GeoPetro and which is the general partner of, and holds a 5% interest in, Redwood LP.

Redwood LP means Redwood Energy Production, L.P., a Texas limited partnership, the sole limited partner of which is GeoPetro and which is 100% owned, directly or indirectly, by GeoPetro.

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Rodessa Formation means the geological formation at the Madisonville Field existing at a depth of approximately 12,000 feet.

Seismic means data collected that uses reflected seismic waves to produce images of the Earth s subsurface. The method requires a controlled seismic source of energy, such as dynamite or a specialized air gun. By noting the time it takes for a reflection to arrive at a receiver, it is possible to estimate the depth of the feature that generated the reflection.

Series A Stock means the preferred stock of GeoPetro designated as Series A preferred stock, all of which converted to GeoPetro s common stock on March 30, 2006.

Series AA Stock means the preferred stock of GeoPetro designated as Series AA preferred stock, all of which converted to GeoPetro s common stock on March 28, 2007.

Tertiary Sandstones means sandstones which were deposited during a geologic time period ranging from 2 to 63 million years ago.

TSX means the Toronto Stock Exchange.

Unevaluated Properties means properties not yet evaluated through exploration and drilling as to whether or not they have proved reserves.

U.S. GAAP means the accounting principles generally accepted in the United States.

Wilson Well means the Wilson No. 1 well located at the Madisonville Field.

Working interest means the percentage of undivided interest held by a party in the oil and/or natural gas or mineral lease granted by the mineral owner, which interest gives the holder the right to work the property (lease) to explore for, develop, produce and market the leased substances.

ABBREVIATIONS AND CONVERSIONS

In this report, the following abbreviations have the meanings set forth below:

API	American Petroleum Institute
bbl and bbls	barrel and barrels, each barrel representing 34.972 Imperial gallons or 42 U.S. gallons
bbls/d	barrels per day
bcf	billion cubic feet
boe	barrels of oil equivalent converting 6 mcf of natural gas to one barrel of oil equivalent and one barrel of natural gas liquids to one barrel of oil equivalent. Measures of boes may be misleading, particularly if used in isolation. This conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead, but is a commonly used industry benchmark.
boe/d	barrels of oil equivalent per day
degree API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28 degree API or higher is generally referred to as light crude oil.
LPG	liquefied petroleum gas
mbbls	one thousand barrels
mboe	one thousand barrels of oil equivalent
mcf	one thousand cubic feet
mcf/d	one thousand cubic feet per day
mmbbls	one million barrels
MMBTU	one million British Thermal Units
MMcf	one million cubic feet
MMcf/d	one million cubic feet per day
NGLs	natural gas liquids
Psig	Pounds per square inch gauge
TCF	trillion cubic feet

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on March 30, 2007.

GEOPETRO RESOURCES COMPANY
By: /s/ Stuart J. Doshi
Stuart J. Doshi
Chairman of the Board of Directors, President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 30, 2007.

Signature	Title	Date
/s/ Stuart J. Doshi Stuart J. Doshi	Chairman of the Board, President and Chief Executive Officer	March 30, 2007
/s/ David V. Creel David V. Creel	Vice President of Exploration and Director	March 30, 2007
/s/ J. Chris Steinhauser J. Chris Steinhauser	Vice President of Finance and Chief Financial Officer, Principal Accounting Officer and Director	March 30, 2007
/s/ Kevin M. Delehanty Kevin M. Delehanty	Director	March 30, 2007
/s/ Thomas D. Cunningham Thomas D. Cunningham	Director	March 30, 2007
/s/ David G. Anderson David G. Anderson	Director	March 30, 2007
/s/ Nick DeMare Nick DeMare	Director	March 30, 2007

GEOPETRO RESOURCES COMPANY

INDEX TO FINANCIAL STATEMENTS

CONSOLIDATED FINANCIAL STATEMENTS FOR THE FISCAL YEARS ENDED DECEMBER 31, 2006, 2005 AND 2004

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

March 29, 2007,

To the Shareholders and Board of Directors

GeoPetro Resources Company

San Francisco, California

We have audited the accompanying consolidated balance sheets of GeoPetro Resources Company and subsidiaries as of December 31, 2006 and 2005, and the related consolidated statements of operations, shareholders equity, and cash flows for each of the three years in the period ended December 31, 2006. These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of GeoPetro Resources Company and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the accompanying consolidated financial statements, effective January 1, 2006, the Company adopted Statement of Financial Accounting Standard No. 123(R), Share-Based Payment.

(Signed) ***HEIN & ASSOCIATES LLP***

Irvine, California

GEOPETRO RESOURCES COMPANY

CONSOLIDATED BALANCE SHEETS

	December 31, 2006	December 31, 2005
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 734,561	$ 914,826
Accounts receivable oil and gas sales	394,337	691,564
Accounts receivable other	115,770	8,392
Related party notes receivable	1,000,000	
Prepaid expenses	121,413	104,111
Total current assets	2,366,081	1,718,893
Oil and Gas Properties, at cost (full cost method):		
Unevaluated properties	4,503,481	3,636,504
Evaluated properties	43,701,510	27,846,543
Less accumulated depletion and impairments	(11,557,257)	(9,130,869)
Net oil and gas properties	36,647,734	22,352,178
Furniture, Fixtures and Equipment, at cost, net of depreciation	41,547	56,013
Other Assets deposits and other noncurrent assets	6,116	6,583
Deferred Offering Costs		881,159
Total Assets	$ 39,061,478	$ 25,014,826
LIABILITIES AND SHAREHOLDERS EQUITY		
Current Liabilities:		
Trade payables	$ 654,427	$ 1,928,169
Short term notes payable	982,301	
Interest payable	73,205	
Dividends payable	133,438	133,438
Production taxes payable	662,905	310,186
Other taxes payable	9,206	24,766
Royalty owners payable	951,271	865,244
Net profits interest payable	137,589	312,663
Total current liabilities	3,604,342	3,574,466
Asset Retirement Obligations	48,842	26,641

See accompanying notes to these consolidated financial statements.

	December 31, 2006	December 31, 2005
Commitments and Contingencies (Note 7)		
Shareholders Equity:		
Series A preferred stock, no par value; 1,000,000 shares authorized 0 shares after conversion on March 30, 2006 and 1,000,000 shares issued and outstanding at December 31, 2005, respectively		674,425
Series AA preferred stock, no par value; 5,000,000 shares authorized 1,890,710 shares issued and outstanding at December 31, 2006, and December 31, 2005, respectively. Liquidation value is $6,750,923 at December 31, 2006, and December 31, 2005, respectively	5,924,068	5,924,068
Common stock, no par value; 100,000,000 shares authorized 27,423,758 and 21,171,923 shares issued and outstanding at December 31, 2006 and December 31, 2005, respectively	40,112,265	24,815,184
Additional paid-in capital	918,381	534,656
Treasury stock, at cost; 1,257,043 shares held at December 31, 2006 and December 31, 2005, respectively	(1,152,435)	(1,152,435)
Accumulated deficit	(10,393,985)	(9,382,179)
Total shareholders equity	35,408,294	21,413,719
Total Liabilities and Shareholders Equity	$ 39,061,478	$ 25,014,826

See accompanying notes to these consolidated financial statements.

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GEOPETRO RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Years Ended December 31, 2006	2005	2004
Revenues			
Oil and gas sales	$ 6,716,360	$ 7,975,990	5,825,072
Costs and expenses:			
Lease operating expense	1,602,932	878,176	780,237
General and administrative	2,347,447	1,551,747	1,963,649
Net profits interest	632,708	856,837	579,590
Impairments expense	38,849		2,038,422
Depreciation and depletion expense	2,406,612	1,832,693	2,077,004
Total costs and expenses	7,028,548	5,119,453	7,438,902
Income (loss) from operations	(312,188)	2,856,537	(1,613,830)
Other Income and (Expense):			
Interest expense	(306,682)	(217,768)	(402,958)
Debt conversion expense			(67,375)
Interest income	198,050	18,969	6,548
Total other expense	(108,632)	(198,799)	(463,785)
Net Income (Loss) Before Taxes	(420,820)	2,657,738	(2,077,615)
Income tax expense	(61,586)	(17,267)	
Net Income (Loss) After Taxes	(482,406)	2,640,471	(2,077,615)
Preferred stock dividend	(529,400)	(529,397)	(529,363)
Net Income (Loss) Available to Common Shareholders	$ (1,011,806)	$ 2,111,074	$ (2,606,978)
Earnings (Loss) per Share:			
Basic	$ (0.04)	$ 0.10	$ (0.14)
Diluted	$ (0.04)	$ 0.09	$ (0.14)
Weighted Average Number of Common Shares Outstanding:			
Basic	25,990,868	20,890,841	18,901,607
Diluted	25,990,868	24,001,888	18,901,607

See accompanying notes to these consolidated financial statements.

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GEOPETRO RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF SHAREHOLDERS EQUITY

FOR THE YEARS ENDED DECEMBER 31, 2006, 2005 and 2004

	Preferred Stock Series A Shares	Preferred Stock Series A Amount	Preferred Stock Series AA Shares	Preferred Stock Series AA Amount	Common stock Shares	Common stock Amount	Additional Paid-in Captial	Treasury Stock	Accumulated Deficit	Total Shareholders Equity
Balances, December 31, 2003	1,000,000	$ 674,425	1,890,710	$ 5,924,068	17,656,950	$ 14,509,961	$	$ (60,000)	$ (8,886,275)	$ 12,162,179
Issuance of common stock for cash, net					1,609,822	3,479,899				3,479,899
Conversion of notes payable					719,147	2,097,500				2,097,500
Treasury stock purchased					(117,647)			(500,000)		(500,000)
Stock compensation expense							500,000			500,000
Fair value of warrants issued with notes payable							31,729			31,729
Net loss									(2,077,615)	(2,077,615)
Dividends on Series AA Preferred									(529,363)	(529,363)
Balances, December 31, 2004	1,000,000	674,425	1,890,710	5,924,068	19,868,272	20,087,360	531,729	(560,000)	(11,493,253)	15,164,329
Issuance of common stock for cash, net					1,443,047	4,727,824				4,727,824
Treasury stock purchased					(139,396)			(592,435)		(592,435)
Fair value of warrants extension							2,927			2,927
Net income									2,640,471	2,640,471
Dividends on Series AA Preferred									(529,397)	(529,397)
Balances, December 31, 2005	1,000,000	674,425	1,890,710	5,924,068	21,171,923	24,815,184	534,656	(1,152,435)	(9,382,179)	21,413,719
Issuance of common stock for cash, net					5,176,835	14,622,656				14,622,656
Series A preferred stock conversion	(1,000,000)	(674,425)			1,000,000	674,425				
Fair value of warrants issued with notes payable							182,390			182,390
Fair market value of the options							201,335			201,335
Net income									(482,406)	(482,406)
Dividends on Series AA Preferred									(529,400)	(529,400)
Balances, December 31, 2006		$	1,890,710	$ 5,924,068	27,348,758	$ 40,112,265	$ 918,381	$ (1,152,435)	$ (10,393,985)	$ 35,408,294

See accompanying notes to these consolidated financial statements.

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GEOPETRO RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31, 2006	2005	2004
Cash Flows From Operating Activities:			
Net income (loss)	$ (482,406)	$ 2,640,471	$ (2,077,615)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation and depletion	2,406,612	1,832,693	2,077,004
Stock compensation expense	201,335	2,927	531,729
Non-cash interest expense	194,691		(17,304)
Impairment expense	38,849		2,038,422
Asset retirement obligations	2,664	1,936	1,237
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	297,226	(239,195)	179,159
(Increase) decrease in other receivables	(107,378)	81,608	(90,000)
(Increase) in prepaid expenses	(17,302)	(77,752)	(15,945)
Deposits and other noncurrent assets	466	(794)	4,625
Increase (decrease) in trade payables	(1,273,742)	662,791	1,013,524
Increase (decrease) in interest payable	73,205	(88,388)	29,034
Increase (decrease) in dividends payable		361	20,769
Increase (decrease) in production taxes payable	352,720	(27,794)	337,980
Increase (decrease) in other taxes payable	(15,561)	(21,522)	46,288
Increase in royalty owners payable	86,027	157,251	74,211
Increase (decrease) in net profit interest payable	(175,074)	91,197	57,518
Increase in asset retirement obligations	19,537		11,094
Net cash provided by operating activities	1,601,869	5,015,790	4,221,730
Cash Flows from Investing Activities:			
Oil and gas property expenditures	(16,721,944)	(5,602,741)	(9,171,589)
Proceeds from sale of oil and gas interest		2,400,000	
Acquisition of furniture, fixtures & equipment	(4,605)	(2,162)	(81,876)
(Increase) in related party notes receivable	(1,000,000)		
Net cash used in investing activities	(17,726,549)	(3,204,903)	(9,253,465)

See accompanying notes to these consolidated financial statements.

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	For the Years Ended December 31, 2006	2005	2004
Cash Flows from Financing Activities:			
Proceeds from sale of common shares, option and warrant exercises, net	16,717,604	4,727,824	3,479,899
Payments of preferred dividends	(529,400)	(529,397)	(529,363)
Proceeds from promissory notes, net	1,900,000		2,075,000
Payments of loan fee	(30,000)		
Repayments of promissory notes	(900,000)	(4,781,807)	(1,158,569)
Deferred offering costs	(1,213,789)	(730,906)	(150,255)
Purchase of treasury stock		(592,435)	
Net cash provided by (used in) financing activities	15,944,415	(1,906,721)	3,716,712
Net Increase in Cash and Cash Equivalents:	(180,265)	(95,834)	(1,315,023)
Cash and Cash Equivalents:			
Beginning of period	914,826	1,010,660	2,325,683
End of period	$ 734,561	$ 914,826	$ 1,010,660
Supplemental Disclosure of Cash Flow Information:			
Cash paid for interest	$ 38,682	$ 291,731	$ 297,266
Cash paid for income taxes	$ 61,586	$	$
Supplemental Disclosure of Non-Cash Investing and Financing Activities:			
Issuance of common stock for conversion of notes payable and cancellation of common stock purchase warrants			$ 2,097,500

See accompanying notes to these consolidated financial statements.

GEOPETRO RESOURCES COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Nature of Operations:

GeoPetro GeoPetro Resources Company (GeoPetro or the Company) was originally incorporated as GeoPetro Company under the laws of the State of Wyoming in 1994 to participate in the oil and gas acquisition, exploration, development and production business in the United States and internationally. GeoPetro Company was subsequently merged into GeoPetro Resources Subsidiary Company, a California corporation, on June 28, 1996. GeoPetro s name was then changed to GeoPetro Resources Company. GeoPetro s corporate offices are in San Francisco, California. The accompanying consolidated financial statements include the accounts of GeoPetro and its wholly-owned subsidiaries. All significant intercompany accounts and transactions have been eliminated in consolidation.

Operations Although GeoPetro is not a development stage enterprise, the company has a limited operating history upon which an evaluation of its business prospects can be based. The risks, expense, and difficulties encountered by early stage companies must be considered when evaluating GeoPetro s business prospects. GeoPetro incurred a net loss of $1,011,806 in 2006, net income of $2,111,074 in 2005, and net loss of $2,606,978 in 2004, and had an accumulated deficit at December 31, 2006, of $10,393,985. GeoPetro expects to make significant capital expenditures in the foreseeable future. Management believes that GeoPetro will be successful in obtaining adequate sources of cash to fund its anticipated capital expenditures through the end of 2007 and to follow through with plans for continued investments in oil and gas properties. GeoPetro s success, in part, depends on its ability to generate additional financing, farm-out certain of its projects and manage its relations with the companies that provide exploration and development services. GeoPetro s success also depends on its ability to effectively manage growth and develop proven reserves. Additionally, GeoPetro s operations are subject to all of the environmental and operational risks normally associated with the oil and gas industry. GeoPetro maintains insurance that is customary in the industry.

Since its inception, GeoPetro has participated as a working interest owner in the acquisition of undeveloped leases, seismic options, lease options and foreign concessions and has participated in seismic surveys and the drilling of test wells on its undeveloped properties. Further leasehold acquisitions and seismic operations are planned for 2007 and future periods. In addition, drilling is scheduled during 2007 and future periods on GeoPetro s undeveloped properties. It is anticipated that these exploration activities together with others that may be entered into may impose financial requirements which may exceed the existing working capital of GeoPetro. Management may raise additional equity and/or debt capital, and has farmed-out certain of its projects to finance its continued participation in planned activities. In the opinion of GeoPetro management, GeoPetro can continue as a going concern even if additional financing is unavailable. However, if additional financing is not available, GeoPetro may be compelled to reduce the scope of its business activities. If GeoPetro is unable to fund planned expenditures, it may be necessary to:

1. forfeit its interest in wells that are proposed to be drilled;

2. farm-out its interest in proposed wells;

3. sell a portion of its interest in prospects and use the sale proceeds to fund its participation for a lesser

interest; and

4. reduce general and administrative expenses.

In order for GeoPetro to maintain its interest in the Indonesian and Australian contract and permit areas, certain work and expenditure commitments must be met or an extension must be granted by the applicable governing authority. In the event that GeoPetro does not meet the commitments and no extensions are granted for meeting the commitments, GeoPetro will forfeit its interest in the contract or permit areas requiring an impairment write-down equal to the capitalized costs recorded for the area forfeited. This could have a material adverse impact on GeoPetro s results of operations in future periods.

In July 2005, GeoPetro entered into agreements with unaffiliated companies that have purchased and are operating a dedicated gas treatment plant and related pipelines to process and transport GeoPetro s gas from the Madisonville Project in Madison County, Texas. These agreements are discussed in detail in Note 10. In connection with the Madisonville Project, GeoPetro re-completed an existing well for production from the Rodessa formation interval at approximately 11,800 feet of depth and completed an injection well for disposal of waste gasses from the production well. GeoPetro initiated gas sales from the Madisonville Project in May 2003. A second well was drilled, tested and completed during 2004 and is presently producing on a restricted rate awaiting a planned expansion of the gas treatment plant. Two additional development wells were drilled during 2006. Another well is planned for drilling during 2007 in the Madisonville Project.

Other than the above work and expenditure commitments, the timing of most of GeoPetro s capital expenditures is discretionary. GeoPetro has no material long-term commitments associated with its capital expenditure plans or operating agreements. Consequently, GeoPetro has a significant degree of flexibility to adjust the level of such expenditures as circumstances warrant. The level of capital expenditures will vary in future periods depending on the success of exploratory drilling activities, gas and oil price conditions and other related economic factors. See Note 11 for a discussion of financing activity subsequent to year end.

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2. Summary of Significant Accounting Policies:

U.S. GAAP The Company s financial statements have been prepared in accordance with accounting principles generally accepted within the United States of America (U.S. GAAP).

Use of Estimates and Significant Estimates Certain amounts in GeoPetro s financial statements are based upon significant estimates, including oil and gas reserve quantities which form the basis for the calculation of depreciation, depletion, amortization and impairment of oil and gas properties. Actual results could materially differ from those estimates.

Oil and Gas Properties GeoPetro follows the full cost method of accounting for oil and gas producing activities and, accordingly, capitalizes all costs incurred in the acquisition, exploration, and development of proved oil and gas properties, including the costs of abandoned properties, dry holes, geophysical costs, and annual lease rentals. All general corporate costs are expensed as incurred. In general, sales or other dispositions of oil and gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded. Amortization of evaluated oil and gas properties is computed on the units of production method based on all proved reserves on a country by country basis. Unevaluated oil and gas properties are assessed for impairment either individually or on an aggregate basis. The net capitalized costs of evaluated oil and gas properties (full cost ceiling limitation) are not to exceed their related estimated future net revenues discounted at 10%, and the lower of cost or estimated fair value of unproved properties, net of tax considerations.

Joint Ventures Some exploration and production activities are conducted jointly with others and, accordingly, the accounts reflect only GeoPetro s proportionate interest in such activities.

Revenue Recognition Revenue is recognized upon delivery of oil and gas production and is shown net of applicable royalty payments, processing and transportation fees. In addition, the Company recognizes revenue from the Madisonville Field net of applicable fees to gather, treat and transport the Company s natural gas production. The applicable fees are paid to unrelated third parties. Revenue from the Madisonville Field is recognized when the price for gas delivered becomes fixed and determinable. The price for gas delivered to the purchaser, Madisonville Gas Processing LP (MGP), becomes fixed and determinable after the gas has been gathered, treated, and transported to a common carrier pipeline where it is then resold by MGP to the common carrier pipeline on a spot market basis. The proceeds from the sale of the gas are deposited directly into an escrow account under the joint signature control of the Company and MGP. The fees to gather, treat and transport the gas are distributed to MGP in accordance with agreements between them and the Company. The remaining net proceeds are distributed to the Company. See Note 10 for a more detailed discussion of the fees under the MGP Agreement.

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Asset Retirement Obligation In accordance with Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* (SFAS 143), the fair value of an asset retirement cost, and corresponding liability, should be recorded as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. GeoPetro recorded an asset retirement obligation to reflect GeoPetro s legal obligations related to future plugging and abandonment of its oil and gas wells. GeoPetro estimated the expected cash flow associated with the obligation and discounted the amount using a credit-adjusted, risk-free interest rate. At least annually, GeoPetro reassesses the obligation to determine whether a change in the estimated obligation is necessary. GeoPetro evaluates whether there are indicators that suggest the estimated cash flows underlying the obligation have materially changed. Should those indicators suggest the estimated obligation has materially changed, GeoPetro will accordingly update its assessment.

	December 31, 2006	2005	2004
Asset retirement obligations, beginning of period	$ 26,641	$ 24,705	$ 12,374
Liabilities incurred	19,537		11,094
Accretion expense	2,664	1,936	1,237
Asset retirement obligations, end of period	$ 48,842	$ 26,641	$ 24,705

Furniture, Fixtures and Equipment Furniture, fixtures and equipment are stated at cost. Depreciation is provided on furniture, fixtures and equipment using the straight-line method over an estimated service life of three to seven years.

Income Taxes GeoPetro accounts for income taxes using the asset and liability method wherein deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which the temporary differences are expected to be recovered or settled. Because management has determined that realization of deferred tax assets is not likely, the net deferred tax assets are fully reserved.

Concentrations of Credit Risk Credit risk represents the accounting loss that would be recognized at the reporting date if counterparties failed completely to perform as contracted. Concentrations of credit risk (whether on or off balance sheet) that arise from financial instruments exist for groups of customers or counterparties when they have similar economic characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in economic or other conditions described below. The credit risk amounts for cash and accounts receivable do not take into account the value of any collateral or security.

GeoPetro maintains several cash accounts with three financial institutions. Accounts at each institution are insured by the Federal Deposit Insurance Corporation up to $100,000. As of December 31, 2006, the uninsured bank balance was $973,682. GeoPetro has not experienced any losses in such accounts and believes it is not exposed to any significant credit risk.

During 2006, 2005 and 2004, the Company had sales to customers exceeding 10% of total sales as follows:

	2006	2005	2004
Customer A	79 %	99.7 %	99.6 %
Customer B	21 %		

At December 31, 2006, 2005 and 2004, the Company had accounts receivable balances from Customer A of $394,337 or 77%, $691,564, or 100%, and $449,947, or 99.5% of total accounts receivable respectively.

Allowance for Doubtful Accounts Trade accounts receivable are recorded at net realizable value. If the financial condition of GeoPetro s customers were to deteriorate, resulting in an impairment of their ability to make payments, additional allowances may be required. Delinquent trade accounts receivable are charged against the allowance for doubtful accounts once uncollectibility has been determined. The allowance is determined through an analysis of the past-due status of accounts receivable and assessments of risk that are based on historical trends and an evaluation of the impact of current and projected economic conditions. There was no activity in the allowance for doubtful accounts as of December 31, 2006 and 2005.

Fair Value of Financial Instruments The estimated fair values for financial instruments are determined at discrete points in time based on relevant market information. These estimates involve uncertainties and cannot be determined with precision. For certain of GeoPetro s financial instruments, including cash, accounts receivable, accounts payable and current portion of notes payable, the carrying amounts approximate fair value due to their maturities.

Stock-Based Compensation Statement of Financial Accounting Standards No. 123, *Accounting for Stock-Based Compensation* (SFAS 123), encourages, but does not require, companies to record compensation cost for stock-based employee compensation at fair value prior to January 1, 2006. GeoPetro elected to account for stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board Opinion No. 25 (APB 25), *Accounting for Stock Issued to Employees,* and related interpretations.

In accordance with SFAS 123, GeoPetro discloses the impact of the fair value accounting of employee stock options. Transactions in equity instruments with non-employees for goods or services have been accounted for using the fair value method as prescribed by SFAS 123.

The following table illustrates the effect on GeoPetro s net loss and loss per share as if GeoPetro had applied the fair value recognition provisions of SFAS 123 to its stock-based employee compensation awards granted in 2003 and in 2005, and recognized expense over the applicable award vesting period. There were no stock-based employee compensation awards granted in 2004.

	As at and for the Years Ended December 31,	
	2005	**2004**
Net income (loss) available to common shareholders as reported	$ 2,111,074	$ (2,606,978)
Compensation FAS 123	(98,870)	(63,655)
Pro forma income (loss)	$ 2,012,204	$ (2,670,633)
Income (loss) per share as reported	$ 0.09	$ (0.14)
Pro forma income (loss) per share	$ 0.08	$ (0.14)

The assumptions made for purposes of estimating the fair value of the stock options are included in Note 8.

Effective January 1, 2006, the Company adopted the fair value recognition provisions of Statement of Financial Accounting Standard 123(R) *Share-Based Payment* (SFAS 123(R)) using the modified prospective transition method. In addition, the Securities and Exchange Commission issued Staff Accounting Bulletin No. 107 *Share-Based Payment* (SAB 107) in March, 2005, which provides supplemental SFAS 123(R) application guidance based on the views of the SEC. Under the modified prospective transition method, compensation cost recognized in the year ended December 31, 2006 includes: (a) compensation cost for all share-based payments granted prior to, but not yet vested as of January 1, 2006, based on the grant date fair value estimated in accordance with the original provisions of SFAS No. 123, and (b) compensation cost for all share-based payments granted beginning January 1, 2006, based on the grant date fair value estimated in accordance with the provisions of SFAS 123(R). In accordance with the modified prospective transition method, results for prior periods have not been restated.

The adoption of SFAS 123(R) resulted in stock compensation expense for the year ended December 31, 2006 of $201,335 to income from continuing operations and income before income taxes, of which the entire amount was recorded to general and administrative expenses. The Company did not recognize a tax benefit from the stock compensation expense because the Company considers it is more likely than not that the related deferred tax assets, which have been reduced by a full valuation allowance, will not be realized.

The fair value of each option grant was estimated on the date of grant using the Black-Scholes option pricing model with the following weighted-average assumptions used for grants in 2003 and 2005: risk-free, weighted-average interest rates ranging from 2.52 to 3.75 percent, expected dividend yield of 0 percent, expected life of 5 years from the date of grant, and expected volatility of 10 and 25 percent. After the initial public offering on March 30, 2006, an expected volatility factor of 58% was used for the newly issued common stock options and the extension of common stock warrants. A newly issued stock option is an option that was granted on or after March 30, 2006 or a previously granted stock option that is modified on or after March 30, 2006. The fair value of all newly issued stock options grants is estimated using the Black-Scholes option pricing model with the following weighted average assumptions used for grants and modifications of prior grants made on or after March 30, 2006 for the twelve months ended December 31, 2006: risk-free, weighted average interest rate of 4.9 percent based on the U.S. Treasury yield curve in effect at the time of grant, expected dividend yield of 0 percent, expected life of 5 years from the date of grant (the remaining term of the option in the case of option extensions), and expected volatility of 58%. GeoPetro has selected 10 publicly traded small cap companies whose primary business is oil and gas exploration and production. Small cap, for purposes of this analysis, is defined as companies with a market capitalization under $1 billion. From this peer group of similar companies, GeoPetro randomly selected 10 companies and derived expected volatility factors for the most recent completed fiscal years for each entity as reported in their recently filed 10K or 10KSB Annual Reports with the Securities and Exchange Commission. Where the expected volatilities were expressed as a range, a simple average of the range is used as an expected volatility for that entity.

The assumptions made for purposes of estimating the fair value of the stock options are included in Note 8.

Income (Loss) Per Common Share Basic earnings per share excludes dilution and is calculated by dividing net income or loss by the weighted average number of common shares outstanding for the period. Diluted earnings per share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock or resulted in the issuance of common stock that then shared from the earnings of the entity. Potential common shares for the periods ended December 31, 2006 and 2004 were excluded from the earnings per share computation because the Company incurred net losses and were anti-dilutive. At December 31, 2005, 1,506,064 outstanding warrants and 20,000 outstanding options to purchase common stock were not included in the diluted EPS calculation because the warrants and options exercise prices were greater than the average market price of the common shares. 1,890,710 shares of Series AA Stock were not included in the diluted EPS calculation at December 31, 2005 because they were anti-dilutive.

	For the Years Ended December 31, 2006	2005	2004
Net Income (Loss) and Adjustments:			
Net Income (Loss) Available to Common Shareholders	$ (1,011,806)	$ 2,111,074	$ (2,606,978)
Adjustments	Anti-dilutive	Anti-dilutive	Anti-dilutive
Net Earnings (Loss) for Diluted Calculation	$ (1,011,806)	$ 2,111,074	$ (2,606,978)
Shares:			
Weighted Average Shares Outstanding	25,990,868	20,890,841	18,901,607
Outstanding Options	Anti-dilutive	1,927,660	Anti-dilutive
Series A Preferred Stock - Conversion	Anti-dilutive	1,000,000	Anti-dilutive
Outstanding Warrants	Anti-dilutive	183,387	Anti-dilutive
Average Number of Shares for Diluted Calculation	25,990,868	24,001,888	18,901,607
Diluted EPS	$ (0.04)	$ 0.09	$ (0.14)

Segment Reporting GeoPetro has oil and gas exploration, development and production operations in the United States, Canada, Australia and Indonesia. All revenues and related costs are associated with operations in the United States. A summary of assets and capital expenditures by geographical segment is included in Note 3.

Cash Equivalents Cash and cash equivalents include cash on hand, amounts held in banks and highly liquid investments purchased with an original maturity of three months or less.

3. SUMMARY OF OIL AND GAS OPERATIONS:

Capitalized costs at year end and costs incurred relating to GeoPetro s oil and gas activities are summarized as follows:

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	United States	Australia	Indonesia	Canada	Totals
2006 Capitalized costs:					
Evaluated properties	$ 40,835,432	$ 2,388,051	$	$ 478,027	$ 43,701,510
Unevaluated properties	1,955,252	1,697,718	759,885	90,626	4,503,481
Less- accumulated depletion and impairment	(8,691,179)	(2,388,051)		(478,027)	(11,557,257)
Net capitalized costs	$ 34,099,505	$ 1,697,718	$ 759,885	$ 90,626	$ 36,647,734
Costs incurred:					
Property acquisition	$ 351,803	$	$	$	$ 351,803
Exploration	(42,834)		576,296	20,561	554,023
Development	15,816,118				15,816,118
Total costs incurred	$ 16,125,087	$	$ 576,296	$ 20,561	$ 16,721,944

	United States	Australia	Indonesia	Canada	Totals
2005 Capitalized costs:					
Evaluated properties	$ 25,019,314	$ 2,388,051	$	$ 439,178	$ 27,846,543
Unevaluated properties	1,646,282	1,697,718	183,589	108,915	3,636,504
Less- accumulated depletion and impairment	(6,303,640)	(2,388,051)		(439,178)	(9,130,869)
Net capitalized costs	$ 20,361,956	$ 1,697,718	$ 183,589	$ 108,915	$ 22,352,178
Costs incurred:					
Property acquisition	$ 1,220,150	$	$	$	$ 1,220,150
Exploration	1,246,550		(2,090,089)	26,564	(816,975)
Development	2,799,567				2,799,567
Total costs incurred	$ 5,266,267	$	$ (2,090,089)	$ 26,564	$ 3,202,742

Generally, sales or dispositions of oil and gas properties, including sales of partial interests in prospects, are treated as adjustments to capitalized costs, with no gain or loss recorded.

Evaluated Oil and Gas Properties In periods prior to 2004 it was determined that the total net costs in the U.S. and Australian evaluated cost pool exceeded their net realizable value. Accordingly, impairment write-downs of $2,426,526 were recorded in the prior periods. During 2004 it was determined that the total net costs in the Australian evaluated cost pool exceeded their net realizable value. Accordingly, impairment write-downs of $1,599,244 were recorded for the year ended December 31, 2004. In addition, an impairment write-down associated with the Canadian evaluated cost pool of $439,178 was recorded for the year ended December 31, 2004 and $38,849 was recorded for the year ended December 31, 2006.

Unevaluated Oil and Gas Properties United States As GeoPetro s properties are evaluated through exploration, they will be included in the amortization base. Costs of unevaluated properties in the United States at December 31, 2006 and 2005 represent exploration costs in connection with GeoPetro s California and Alaskan prospects. The prospects and their related costs in unevaluated properties have been assessed individually. The current status of these prospects is that seismic data is being interpreted on an on-going basis on the subject lands within the prospects.

Drilling in California and Alaskan prospects is expected to commence as early as 2007 and will continue in future periods. As the prospects are evaluated through drilling in future periods, the property acquisition and exploration costs associated with the wells drilled will be transferred to evaluated properties where they will be subject to amortization.

Unevaluated Oil and Gas Properties Australia Unevaluated costs incurred in Australia represent costs in connection with the exploration of two exploration permit areas in Australia. The prospects and their related costs in unevaluated properties have been assessed individually and no impairment charges were considered necessary for the Australian properties for any of the periods presented. The current status of these prospects is that appraisal wells have been drilled and are being evaluated for commerciality on the subject lands within the prospects.

Unevaluated Oil and Gas Properties Indonesia Unevaluated costs incurred in Indonesia represent costs in connection with one production sharing contract area in Indonesia and costs incurred in pursuing additional oil and gas projects in Indonesia. The prospect and its related costs in unevaluated properties have been assessed individually and no impairment charges were considered necessary for the Indonesian property for any of the periods presented. The current status of this prospect is that four exploratory locations have been identified for drilling in 2007 on the subject lands within the prospect. A drill rig has been transported to the prospect and is expected to commence drilling the first of four planned wells in the second quarter of 2007. In October 2005, the Company sold its interest in another Indonesian production sharing contract for cash consideration of $2,400,000. The proceeds realized were credited to the Indonesian unevaluated cost pool.

As noted, drilling is expected to commence on the remaining production sharing contract in 2007 and is expected to continue in future periods. As the prospect is evaluated through drilling in future periods, the property acquisition and exploration costs associated with the wells drilled will be transferred to evaluated properties where they will be subject to amortization.

The Company s interest in the production sharing contract is 12% and is held in its partially owned subsidiary, C-G Bengara. The production sharing contract is subject to prior work commitments for the eight-year period ended December 3, 2006 requiring total expenditures of $24 million. As of September 30, 2006, approximately $6.3 million of the $24.0 million required expenditures had been met, leaving an approximate $17.7 million shortfall. BP Migas, the applicable governing authority, has granted a deferral of the prior years commitments. On September 29, 2006, the Company sold to CNPC 70% of its interest in C-G Bengara and the underlying rights to the production sharing contract, reducing its interest from 40% to 12%. Per the terms of the agreement, CNPC deposited an $18.7 million earning obligation into an account jointly controlled by CNPC, Continental and the Company. The funds are to be used exclusively to pay for 2007 exploration drilling in the production sharing contract. The earning obligation funds of $18.7 million, together with the $6.3 million previously spent, are expected to satisfy all of the past and future work commitments on the production sharing contract. As noted above, four exploration wells are planned for drilling in 2007 with drilling activities expected to commence in the second quarter of 2007.

In the event that the Company does not meet the work program commitments and provided that no extensions are granted for meeting the commitments, the Company must forfeit its interest in the production sharing contract. If the Company forfeits its interest, it will be necessary to record an impairment write-down equal to the capitalized costs recorded for the area forfeited.

Breakdown of Unevaluated Oil and Gas Properties The following table sets forth a summary of oil and gas property costs not being amortized at December 31, 2006, by the period in which the costs were incurred:

	Totals	**Year Ended December 31, 2006**	**Year Ended December 31, 2005**	**Year Ended December 31, 2004**	**2003 and Prior Years**
Unproved property acquisition	$ 1,853,945	$ 351,803	$	$ 13,475	$ 1,488,667
Exploration	2,649,536	515,174	(816,974)	(68,144)	3,019,480
Total	$ 4,503,481	$ 866,977	$ (816,974)	$ (54,669)	$ 4,508,147

Management expects that planned activities for the year 2007 will enable the evaluation of approximately 5% of the costs as of December 31, 2006. Evaluation of 30% of the remaining costs is expected to occur in 2008 with the remaining 65% in 2009 and beyond.

4. SHORT AND LONG-TERM DEBT:

Short term non-convertible debt at December 31, 2006 and 2005 consisted of the following:

	2006	**2005**
Amounts Due Unrelated Parties:		
Promissory note dated January 31, 2006, payable to Pinehill Capital; collateralized with an undivided 5% of the net cash flow in GeoPetro s Madisonville Project; payable on or before January 31, 2007, including interest at 8% (a)	1,073,205	
	$ 1,073,205	$

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(a) The Company issued a $1,000,000 short term promissory note on January 31, 2006 with a maturity date of January 31, 2007. The note may be repaid at any time without penalty. In the event the note is not repaid by the maturity date, the Company has agreed to dedicate 5% of the net cash flow from the Madisonville Project in Texas toward the repayment of the note and any accrued interest thereon. In connection with the note, the Company paid a loan origination fee of $30,000 and granted a three-year exercisable warrant to purchase 150,000 Common Shares at $3.50 per share. The fair value of the warrants on the date of issuance, $182,390, as well as the $30,000 loan origination fee, was recorded as a debt discount and is being amortized over the life of the promissory note. As of December 31, 2006, the unamortized debt discount was $17,699.

5. INCOME TAXES:

The provision for income taxes consist of the following:

	2006	2005
Current		
Federal	$ 59,500	$ 16,000
State	2,500	1,000
Total	62,000	17,000
Deferred		
Federal		
State		
Total		
Total Income Provision	$ 62,000	$ 17,000

The actual income tax (benefit) expense differs from the expected tax (benefit) expense as computed by applying the US Federal corporate income tax rate of 35% for each period as follows:

	2006	2005
Amount of expected tax (benefit) expense	$ (169,000)	$ 930,000
Non-deductible expenses	5,000	5,000
Alternative minimum tax		17,000
Expiration of net operating loss		(49,000)
Utilization of NOL	630,000	
Other	(10,000)	5,000
Valuation allowance adjustment	(394,000)	(891,000)
	$ 62,000	$ 17,000

Deferred income taxes reflect the net tax effects of temporary differences between carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Significant components of the Company s deferred tax assets (liabilities) are as follows:

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	2006	2005
Deferred tax assets (liabilities):		
Net operating loss carryforwards	$ 8,654,000	$ 6,061,000
Oil and gas property basis differences	(5,069,000)	(2,018,000)
Credit carryforawrds		16,000
Stock compensation	74,000	
Other	13,000	6,000
Total deferred tax assets	3,672,000	4,065,000
Valuation allowance	(3,672,000)	(4,065,000)
Total net deferred taxes	$	$

As of December 31, 2006, GeoPetro had net operating loss (NOL) carryforwards of approximately $22,932,000 for federal beginning to expire in 2010 and $10,926,000 for state which began to expire in 2006. A significant change in ownership of GeoPetro may limit GeoPetro s ability to use these NOL carryforwards.

6. **RELATED PARTY TRANSACTIONS**:

The Company appointed David G. Anderson as a Director on March 30, 2006. Mr. Anderson is the Senior Vice President and a director of Dundee Securities Corporation, the lead underwriter in connection with a sale of common shares the Company completed on March 30, 2006. The decision to distribute the common shares and the determination of the terms of the distribution were made through arm s length negotiations primarily between the Company and Dundee Securities Corporation as lead underwriter. Mr. Anderson had some involvement in such negotiations solely in his capacity as a director and officer of Dundee Securities Corporation. Dundee Securities Corporation received an underwriters fee totaling $632,000 in connection with the offering.

On June 6, 2005 the Company purchased 139,396 shares of common stock from Stuart Doshi, the Company s President and Chief Executive officer, at the estimated fair market value prices on that date of $4.25 per share for a total of $592,433. The Company believes the purchase price of $4.25 per share was at least as favorable to the Company as could have been obtained through arm s length negotiations with unaffiliated third parties since the Company also sold 939,194 shares of common stock for $4.25 per share in 2005.

On August 27, 2004, Mr. Doshi exercised an option to purchase 500,000 shares of common stock at an exercise price of $1.00 per share. The option was granted to Mr. Doshi on August 30, 1999 pursuant to his services as Chief Executive Officer of the Company.

On May 31, 2005, David Creel, Vice President of Exploration and a director, exercised options to purchase 200,000 shares of common stock at an exercise price of $2.00 per share. The options were granted to Mr. Creel pursuant to his services as Vice President of Exploration as follows: (i) 100,000 options on June 1, 1998 and (ii) 100,000 options on June 1, 2000.

On April 29, 2005, Thomas Cunningham, a director, exercised an option to purchase 100,000 shares of common stock at an exercise price of $2.00 per share. The option was granted to Mr. Cunningham on April 30, 2000 pursuant to his services as a director.

On March 25, 2004, Kevin Delehanty, a director, exercised an option to purchase 70,900 shares of common stock at an exercise price of $1.00 per share. The option was granted to Mr. Delehanty on August 30, 1999 pursuant to his services as a director.

On August 25, 2004, Mr. Delehanty exercised a warrant to purchase 100,000 shares of common stock at an exercise price of $1.00 per share. The warrant was granted to Mr. Delehanty on August 30, 1999 pursuant to his services as a director.

During 2004, the Company paid cash finders fees of $165,670 to Mr. Delehanty in connection with the Company s equity and debt financings as follows: (i) $86,545 relating to the private placement issuances of 350,800 shares of common stock at $4.25 per share during July, August and September of 2004, and (ii) $79,125 relating to the conversion into common stock of certain promissory notes and warrants held by a 5% shareholder as described below.

Effective March 22, 2004, the Company issued 539,000 shares of common stock to G. Carter Sednaoui and Rolling Hill Investors, LLC, an entity owned by Mr. Sednaoui, a 5% shareholder, pursuant to the exercise of warrants. Concurrently, Mr. Sednaoui and Rolling Hill Investors, LLC agreed to a $1,347,500 reduction in the principal balance of certain of the Company s promissory notes payable as consideration for the exercise of the warrants. The common stock warrants were exercisable at a price of $2.50 and had an expiration date of December 31, 2008. The largest aggregate amount of principal outstanding on these promissory notes payable during 2004 was $5,130,180. A total of $2,508,948 in principal repayments were made toward the promissory notes during 2004. A total of $334,358 of interest was paid toward the promissory notes during 2004 at interest rates between 8% and 11%. The promissory notes have been repaid in their entirety.

On June 7, 2006, the Company loaned $1,000,000 to G. Carter Sedanoui (Borrower), a shareholder, evidenced by a short term promissory note payable to the Company with a maturity date on March 31, 2007. The note may be repaid at any time without penalty. In the event the note isn t repaid by the maturity date, the Company has full recourse against the Borrower. In addition, the Borrower has granted a security interest in 564,120 shares of the Company s common stock.

Effective September 17, 2004, the Company issued 62,500 shares of common stock to Mr. Sednaoui pursuant to the conversion of a $250,000 convertible note payable. The convertible note was issued on September 18, 2001 at an interest rate of 8% per annum for the purposes of funding the Company s capital expenditures in the Madisonville Project in Texas. The largest aggregate amount of principal outstanding of this convertible note payable during 2004 was

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$250,000. A total of $14,262 of interest was paid toward the promissory note during 2004 at an interest rate of 8%. As indicated, the note was converted in 2004.

Effective September 30, 2004, the Company issued 117,648 shares of common stock to Mr. Sednaoui in exchange for a $500,000 reduction in the principal balance of a promissory note payable dated July 19, 2004 as consideration. The largest aggregate amount of principal outstanding of this promissory note payable during 2004 was $2,000,000. A total of $500,000 in principal repayments were made toward the promissory note during 2004. A total of $37,145 of interest was paid toward the promissory note during 2004 at an interest rate of 8%. The promissory note has been repaid in its entirety.

During 2004, the Company sold 378,448 shares of common stock at a price of $4.25 per share to Mr. Sednaoui and certain entities owned and controlled by him. The Company believes the purchase price of $4.25 per share was at least as favorable to the Company as could have been obtained through arm s length negotiations with unaffiliated third parties since the Company sold 939,194 shares of its common stock for $4.25 per share in the first half of 2005.

Presently, Eric Doshi, Stuart Doshi s son, is employed as the Company s Manager of Planning at an annual salary of $120,000 per year. The Company paid Eric Doshi $37,500, $78,540 and $105,689 during 2006, 2005 and 2004, respectively, for his services. Eric Doshi s salary, based on industry comparables, was at least as favorable to the Company as could have been obtained through arm s length negotiations with unaffiliated third parties.

7. SHAREHOLDERS EQUITY:

GeoPetro s articles of incorporation allow for the issuance of 100,000,000 shares of common stock, 1,000,000 shares of Series A preferred stock (Series A Stock), 5,000,000 shares of Series AA preferred stock (Series AA Stock), and an additional 44,000,000 shares of preferred stock which may be issued from time to time in one or more series.

Common Stock The holders of common stock are entitled to one vote per share. Subject to preferences on outstanding preferred stock, the holders of common stock are entitled to receive ratably such dividends as may be declared by the board of directors. In the event of a liquidation, the holders of common stock and Series A preferred stock are entitled to share ratably in all assets remaining after payment of liabilities, subject to prior distribution rights of preferred stock.

Conversion of Series A Stock Upon completion of the Company s initial public offering on March 30, 2006, all of the 1,000,000 shares of Series A Stock automatically converted into a like number of common shares.

Preferred Stock - Significant rights and preferences attaching to the Series AA Stock are as follows:

Dividends The holders of Series AA Stock are entitled to receive ratably such cash dividends, if any, as may be declared from time to time by the board of directors out of funds legally available therefore and when declared, dividends shall be paid at the rate of $0.07 per

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share each calendar quarter. Any quarterly dividends not paid when due shall be accrued and shall accumulate until paid.

Preference in Liquidation In the event of a liquidation, dissolution or winding up of GeoPetro, the holders of Series AA Stock are entitled to receive, prior and in preference to any distribution of any assets or surplus funds to the holders of Series A Stock and common stock, an amount equal to $3.50 per share plus any dividends declared but unpaid on such shares, but no more.

Voting Rights The holders of Series AA Stock are entitled to the number of votes equal to the number of shares of common stock into which each share of preferred stock is convertible on the record date for the vote.

Conversion Each share of Series AA Stock is convertible, at the option of the holder, into fully paid and nonassessable shares of common stock on a one-for-one basis, subject to certain adjustments. If GeoPetro s common stock is listed on a national or regional exchange, including the NASD Over-the-Counter Bulletin Board, the Series AA Stock will automatically convert into shares of GeoPetro common stock on a one-for-one share basis effective the first trading day after the reported high selling price for GeoPetro s common stock is at least $5.25 per share for any consecutive ten trading days. If an automatic conversion occurs within one year after issuance of the Series AA Stock, a holder will receive, on the one year anniversary date of the issuance of the Series AA Stock, a final cash dividend equivalent to a full year of dividends less any dividends paid before such conversion.

8. COMMON STOCK OPTIONS:

Effective as of September 10, 2001, the board of directors approved an incentive stock plan, providing for awards under the terms and provisions of such plan of incentive stock options, stock appreciation rights and restricted stock awards to officers, directors and employees of GeoPetro and its consultants (the Stock Incentive Plan). The plan provides, among other provisions, the following:

The maximum number of Common Shares which may be awarded, optioned and sold under the plan is 5,000,000 (subject to adjustment for stock splits, stock dividends and certain other adjustments to GeoPetro s common stock); and the per share exercise price for Common Shares to be issued pursuant to the exercise of an option shall be no less than the fair market value of GeoPetro s Common Shares as of the date of grant.

The Stock Incentive Plan provides for the granting to employees of incentive stock options within the meaning of Section 422 of the United States Internal Revenue Code of 1986, as amended, and for the granting of non-statutory stock options to directors who are not employees and consultants. In the case of employees who receive incentive stock options which are first exercisable in a particular calendar year and the aggregate fair market value of which exceeds $100,000, the excess of the $100,000 limitation shall be treated as a nonstatutory stock option under the Stock Incentive Plan.

The Stock Incentive Plan is being administered by the Board of Directors. The Board of Directors determines the terms of the options granted, including the number of Common Shares subject to each option, the exercisability and vesting requirements of each option, and the form of consideration payable upon the exercise of such option (i.e., whether cash or exchange of existing Common Shares in a cashless transaction or a combination thereof).

The Stock Incentive Plan will continue in effect for 10 years from September 10, 2001 (i.e., the date first adopted by the Board), unless sooner terminated by the board of directors. The Company has implemented a new 2004 Stock Option and Appreciation Rights Plan (the Stock Option Plan) for the issuance of options to purchase Common Shares and/or stock appreciation rights in 2004 or thereafter to directors, officers, employees and consultants of the Company and its subsidiaries. The Stock Option Plan has replaced the Stock Incentive Plan. Outstanding options issued under the Stock Incentive Plan will continue to be outstanding in accordance with their terms and the terms of the Stock Incentive Plan, but will count toward the limits in the amount of Common Shares available to be issued under the Stock Option Plan.

During 2004 no options were issued to employees or directors. No stock-based compensation was recognized for the years ended December 31, 2005. Effective January 1, 2006, the Company adopted SFAS 123 (R) resulting in stock compensation expense for the twelve months period ended December 31, 2006 of $201,335. During 2004, the Company issued 500,000 shares of our common stock for cash proceeds of $500,000 in connection with the exercise of stock options by an officer and director. Concurred with the exercise of stock options, the officer sold 117,647 shares of common stock to the Company at the estimated fair market value prevailing at that time of $4.25 per share. We recorded compensation expense of $500,000 in connection with the purchase of stock. During 2006, 150,000 stock options were issued to directors and during 2005, 20,000 stock options were issued to employees pursuant to the Stock Option Plan.

A summary of the status of GeoPetro s stock option plan is as follows:

	Options	**Exercise Prices**	**Weighted Average Exercise Price**
Outstanding at December 31, 2003	4,839,750	$0.50 to $3.00	$ 1.66
Granted			
Exercised	(584,500)	$1.00 to $1.25	1.00
Expired	(100,000)	$1.00	1.00
Outstanding at December 31, 2004	4,155,250	$0.50 to $3.00	1.77
Granted	20,000	$4.25 to $6.25	5.25
Exercised	(300,000)	$2.00	2.00
Outstanding at December 31, 2005	3,875,250	$0.50 to $6.25	1.77
Granted	150,000	$3.85	3.85
Exercised			
Expired	(20,000)	$3.00	3.00
Outstanding at December 31, 2006	4,005,250	$0.50 to $6.25	$ 1.84

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The weighted average fair value of options granted during the year ended December 31, 2005, as calculated under the Black-Scholes pricing model is $0.70 per share and for the weighted average fair value of options granted in 2006, as calculated under the same method is $1.83 per share.

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted-average assumptions used for grants in 2005 and 2006: risk-free, weighted-average interest rates ranging from 3.75 to 4.9 percent, expected dividend yield of 0 percent, expected life of 5 years from the date of grant, and expected volatility of 10 and 58 percent.

The options outstanding as of December 31, 2006 have the following contractual lives:

Number of Options Outstanding	**Number of Options Exercisable**	**Exercise Prices**	**Weighted Average Remaining Contractual Life**
750,000	750,000	0.50	1.33
45,250	45,250	1.25	0.16
1,290,000	1,290,000	2.00	0.99
1,750,000	1,050,000	2.10	6.43
150,000	20,000	3.85	4.29
10,000	4,000	4.25	3.01
10,000	2,000	6.25	3.44
4,005,250	3,161,250		

As of December 31, 2006, there are 3,161,250 options which are exercisable. The remaining 844,000 options will become exercisable ratably over the next four years.

9. <u>Common Stock Warrants</u>:

In conjunction with the finance with a short term note payable during 2006, GeoPetro issued warrants to purchase 150,000 shares of GeoPetro s common stock at exercise prices of $3.50 per share. The purchase rights under the warrants have expiration date of January 31, 2009 unless terminated earlier in accordance with the stock warrant purchase agreement. The fair value of the warrants issued on the date of the grant, $182,390, was recorded as a discount to notes payable and is being amortized as interest expense over the term of the note. As of December 31, 2006, the unamortized amount is $17,966.

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The following table summarizes the number of shares reserved for the exercise of common stock purchase warrants as of December 31, 2006:

	Expiration Date	Exercise Price	12/31/2005 Shares	Warrants Exercised	Warrants Granted	Warrants (Expired)	12/31/2006 SHARES
Common Stock	06/30/06	$ 5.00	10,000			(10,000)	
Common Stock	11/01/06	$ 3.00	20,000			(20,000)	
Common Stock	12/31/06	$ 4.00	10,000			(10,000)	
Common Stock	12/31/06	$ 2.00	75,000	(75,000)			
Common Stock	05/01/07	$ 5.25	5,000				5,000
Common Stock	02/28/08	$ 5.00	27,000				27,000
Common Stock	03/31/08	$ 3.50	25,000				25,000
Common Stock	07/19/08	$ 5.00	50,000				50,000
Common Stock	09/30/08	$ 5.00	14,375				14,375
Common Stock	12/15/08	$ 3.50	1,131,355				1,131,355
Common Stock	03/31/09	$ 5.25	100,000				100,000
Common Stock	01/31/09	$ 3.50			150,000		150,000
Related party:							
Common Stock	06/18/07	$ 2.00	150,000				150,000
Common Stock	04/30/08	$ 3.00	33,333				33,333
Common Stock	12/31/06	$ 4.00	66,667			(66,667)	
Common Stock	06/18/07	$ 4.00	33,333				33,333
Common Stock	06/18/07	$ 5.00	33,334				33,334
Common Stock	12/31/08	$ 2.00	185,125				185,125
			1,969,522	(75,000)	150,000	(106,667)	1,937,855

In conjunction with the issuance of units of equity securities during 2005, GeoPetro issued warrants to purchase 37,000 shares of GeoPetro s common stock at exercise prices of $5.00 per share. The purchase rights under the warrants have expiration dates from June 30, 2006 to February 28, 2008 unless terminated earlier in accordance with the stock warrant purchase agreement. The Company agreed to extend the warrants by a period of one year for a total of 143,334 shares. The fair value of the warrants on the date of extension, $32,404, was recorded as compensation expense and $2,927 was recorded as consulting expense.

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The following table summarizes the number of shares reserved for the exercise of common stock purchase warrants as of December 31, 2005:

	Expiration Date	Exercise Price	12/31/04 Shares	Warrants Exercised	Warrants Granted	Warrants Extended (expired)	12/31/05 Shares
Common Stock	03/31/05	$ 2.00	37,500	(37,500)			
Common Stock	03/31/05	$ 3.00	10,000	(10,000)			
Common Stock	04/30/05	$ 2.50	10,000	(10,000)			
Common Stock	07/31/05	$ 2.00	37,500	(37,500)			
Common Stock	07/31/05	$ 3.00	10,000			(10,000)	
Common Stock	12/31/05	$ 5.00	50,000			(50,000)	
Common Stock	06/30/06	$ 5.00			10,000		10,000
Common Stock	11/01/06	$ 3.00	20,000				20,000
Common Stock	12/31/06	$ 4.00	10,000				10,000
Common Stock	12/31/06	$ 2.00	75,000				75,000
Common Stock	05/01/07	$ 5.25	5,000				5,000
Common Stock	02/28/06	$ 5.00			27,000		27,000
Common Stock	03/31/08	$ 3.50	25,000				25,000
Common Stock	07/19/08	$ 5.00	50,000				50,000
Common Stock	09/30/08	$ 5.00	14,375				14,375
Common Stock	12/15/08	$ 3.50	1,161,356	(30,000)		(1)	1,131,355
Common Stock	03/31/09	$ 5.25	100,000				100,000
Related Party:							
Common Stock	06/18/06	$ 2.00	150,000				150,000
Common Stock	06/18/06	$ 3.00	33,333				33,333
Common Stock	12/31/06	$ 4.00	66,667				66,667
Common Stock	06/18/07	$ 4.00	33,333				33,333
Common Stock	06/18/07	$ 5.00	33,334				33,334
Common Stock	12/31/08	$ 2.00	185,125				185,125
			2,117,523	(125,000)	37,000	(60,001)	1,969,522

In conjunction with the issuance of units of equity securities during 2004, GeoPetro issued warrants to purchase 155,000 shares of GeoPetro s common stock at exercise prices ranging from $5.00 to $5.25 per share. The purchase rights under the warrants have expiration dates from December 31, 2005 to March 31, 2009 unless terminated earlier in accordance with the stock warrant purchase agreement.

During 2004, in conjunction with the issuance of promissory notes, GeoPetro issued warrants to purchase 64,375 shares of GeoPetro s common stock at an exercise price of $5.00 per share. The purchase rights under the warrants have expiration dates from July 19 to September 30, 2008, unless terminated earlier in accordance with the stock warrant purchase agreement. The fair value of the warrants on the date of issuance, $31,729, was recorded as a debt discount and was being amortized over the life of the promissory notes.

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The following table summarizes the number of shares reserved for the exercise of common stock purchase warrants as of December 31, 2004:

	Expiration Date	Exercise Price	12/31/03 Shares	Warrants Exercised	Warrants Granted	Warrants Extended (canceled)	12/31/04 Shares
Common Stock	09/17/04	$ 2.50	100,000			(100,000)	
Common Stock	03/31/05	$ 2.00	37,500				37,500
Common Stock	03/31/05	$ 3.00	10,000				10,000
Common Stock	04/30/05	$ 2.50	10,000				10,000
Common Stock	07/31/05	$ 2.00	37,500				37,500
Common Stock	07/31/05	$ 3.00	10,000				10,000
Common Stock	12/31/05	$ 4.00	10,000				10,000
Common Stock	12/31/05	$ 5.00			50,000		50,000
Common Stock	11/01/06	$ 3.00	20,000				20,000
Common Stock	12/31/06	$ 2.00	75,000				75,000
Common Stock	05/01/07	$ 5.25			5,000		5,000
Common Stock	03/31/08	$ 3.50	25,000				25,000
Common Stock	07/19/08	$ 5.00			50,000		50,000
Common Stock	09/30/08	$ 5.00			14,375		14,375
Common Stock	12/15/08	$ 3.50	1,161,356				1,161,356
Common Stock	12/31/08	$ 2.50	439,000			(439,000)	
Common Stock	03/31/09	$ 5.25	100,000		100,000		100,000
Related Party:							
Common Stock	08/30/04	$ 1.00	100,000	(100,000)			
Common Stock	06/18/06	$ 2.00	150,000				150,000
Common Stock	06/18/06	$ 3.00	33,333				33,333
Common Stock	12/31/06	$ 4.00	66,667				66,667
Common Stock	06/18/07	$ 4.00	33,333				33,333
Common Stock	06/18/07	$ 5.00	33,334				33,334
Common Stock	12/31/08	$ 2.00	185,125				185,125
			2,537,148	(100,000)	219,375	(539,000)	2,117,523

10. Commitments and Contingencies:

Employment Agreements The Company entered into a contract of employment with Stuart J. Doshi, Founder, President, Chief Executive Officer and Chairman of the Board of Directors, dated July 28, 1997 (effective July 1, 1997) and amended on January 11, 2001, July 1, 2003, April 20, 2004, May 9, 2005, July 28, 2005 and January 30, 2006. The contract as amended provides for a five-year term commencing May 1, 2005 which term is automatically extended for successive two-year renewal terms unless: (a) the board of directors elects not to renew the contract and the Company provides notice to Mr. Doshi of such non-renewal at least six months prior to the expiry of his employment term or any renewal term, or (b) Mr. Doshi attains age 75, in which case the term ends upon the completion of the calendar year in which he becomes 75 years old unless the Company and Mr. Doshi mutually agree to one-year extensions. The contract of employment currently provides for an annual base salary of $300,000 and further provides that in the event of a change of control of the Company or if Mr. Doshi is terminated without cause, he is entitled to receive (a) in exchange for all

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of his vested stock options and vested restricted shares, such number of Common Shares having a market value equal to the difference between (x) the aggregate total market value of all vested restricted shares and Common Shares he would receive upon exercise of all vested stock options less (y) the aggregate total exercise price for all of his vested stock options; provided, however, that if the Common Shares to be delivered to Mr. Doshi upon such change of control or termination have not been registered so as to permit immediate public resale, Mr. Doshi shall instead receive a cash payment equal to the market value on the date of termination of all vested stock options and restricted shares without any discount for liquidity or minority position against cancellation of such options and restricted shares, (b) a cash payment equal to the greater of (i) his compensation for the remainder of his term, including salary and the aggregate amount of his bonuses in respect of the last four fiscal years and (ii) four times his compensation in the current year, including his then-current salary and the average amount of his bonuses for the last four fiscal years, and (c) an additional cash payment representing his employment benefits equal to 20% of the amount of salary he is entitled to receive under (b)(i) or (b)(ii) above, as applicable. In addition, in the event of a change of control or termination without cause, all unvested options issued by the Company to Mr. Doshi will vest.

GeoPetro has executed an employment contract dated April 28, 1998 and amended on June 15, 2000, May 12, 2003 and January 1, 2005 with its Vice President of Exploration, David V. Creel. The contract provides an annual salary of $150,000 and may be terminated by GeoPetro without cause upon the payment to Mr. Creel of cash payments equal to the lesser of three months base salary or base salary during the remainder of the employment term, and, in the event of termination without cause, all unvested options issued by GeoPetro to Mr. Creel will vest.

GeoPetro has executed an employment contract dated June 19, 2000 and amended on December 12, 2002 and January 1, 2005 with its Vice President of Finance and Chief Financial Officer, J. Chris Steinhauser. The contract provides for an annual salary of $150,000 and may be terminated by GeoPetro without cause upon the making of cash payments equal to the lesser of three months base salary or base salary during the remainder of the employment term, and, in the event of termination without cause, all unvested warrants issued by GeoPetro to Mr. Steinhauser will vest.

Office Lease Effective March 1, 2004, GeoPetro is committed under an office sublease which provides for a sixty month term. The sublease provides for minimum monthly lease payments of $5,788 during the first thirty-six months of the lease term and $6,527 per month from the thirty-seventh month to the sixtieth month. Minimum annual rentals due under this agreement are as follows:

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Year	Amount
2007	76,856
2008	78,334
2009	13,056

Rent expense for the years ended December 31, 2006, 2005 and 2004, was approximately $69,466, $69,466, and $67,138, respectively, and is included in general and administrative expenses in the accompanying statements of operations.

Madisonville MGP Agreement GeoPetro owns a 100% working interest in leases located in Madisonville (Rodessa) Field in Madison County, Texas. GeoPetro s working interest covers the Rodessa formation interval at approximately 11,800 feet of depth. The Rodessa reserves are being developed through the re-entry and recompletion of the Ruby Magness No. 1 well (originally drilled in 1994) and the drilling of additional well locations. The natural gas in the Rodessa formation contains 28% impurities which must be removed in order to meet pipeline quality specifications.

In this connection, GeoPetro entered into agreements with a subsidiary of a NYSE listed company, Hanover Compressor Company (Hanover), that funded, constructed, installed and operated a dedicated gas treatment plant to process the Rodessa gas. The gas treatment plant is presently capable of treating and bringing up to pipeline specifications approximately 18 million cubic feet of inlet gas per day. Gateway Processing Company (Gateway) has installed field gathering pipelines and a sales pipeline with an estimated capacity of at least70 million cubic feet of gas per day to transport the treated natural gas to a major pipeline in the area.

Effective July 25, 2005, Madisonville Gas Processing, LP (**MGP**) purchased the natural gas treatment plant from Hanover. Concurrent with MGP s purchase of the gas treatment plant, the Company, Gateway and MGP terminated the Hanover/Gateway agreements and entered into a new agreement, (the **MGP Agreement**), to treat and transport the Company s gas production from the Madisonville Project. As a result of the MGP Agreement, MGP has committed to install and make operational additional treating facilities capable of treating 50 MMcf/d, which combined with the capacity of the current in-service treating facilities will represent a total treating capacity of 68 MMcf/d for the Madisonville treatment plant.

The term of the MGP Agreement commenced August 1, 2005 and continues so long as the Company owns any oil and gas leases in the Madisonville Field, provided that it shall terminate 30 years from the effective date unless extended. Under the terms of the MGP Agreement, the Company has committed all natural gas production from its interest in the Madisonville Project to MGP. MGP purchases the untreated natural gas from the Company at the well site point of delivery for a net price equal to the weighted average price per MMBTU that MGP receives for the natural gas delivered to the sales pipeline less certain gathering, treatment and transportation charges. The gathering, treatment and transportation price adjustments are described below. All proceeds from MGP s sale of Rodessa Formation gas are deposited in an escrow account and then disbursed in accordance with the joint direction of the Company and MGP.

The MGP Agreement provides that certain gathering, treating and transportation fees shall be paid to MGP from the escrow account. The MGP Agreement provides that MGP will receive a gathering and marketing fee of $0.07 and $0.01 per Mcf, respectively, of gas measured and delivered to the natural gas treatment plant. In addition, for the first 18,000 Mcf/d of gas measured and delivered to the inlet flange of the gas treatment plant, MGP will receive a treating fee of $1.50 per Mcf. This treating fee will remain in effect until September 30, 2010. For any gas volumes in excess of 18,000 Mcf/d of gas delivered to the inlet flange of the gas treatment plant, MGP will receive a treating fee of $1.10 per Mcf. Beginning October 1, 2010, this fee of $1.10 per Mcf shall be charged for all gas measured and delivered to the plant. One-quarter (1/4) of the foregoing treating fees will be adjusted using the Producer Price Index for Industrial Commodities (PPI) and one-quarter (1/4) using the Consumer Price Index (CPI) commencing January 1, 2006. One-half (1/2) of the foregoing gathering and marketing fees will be adjusted using the Consumer Price Index (CPI) commencing January 1, 2006. The Company has the right, upon giving 60 days notice, to terminate the marketing fee whereupon it shall assume the sole responsibility of marketing the natural gas sold.

For the first 18,000 Mcf/d of gas measured and delivered to the inlet flange of the gas treatment plant, Gateway will receive a transportation fee of $0.10 per Mcf. This fee will remain in effect for 36 months from the effective date of the MGP Agreement. Beginning in the 37th month and terminating at the end of the 60th month from the effective date of the MGP Agreement, the fee shall be reduced to $0.08 per Mcf for the first 18,000 Mcf/d of gas measured and delivered to the inlet flange of the gas treatment plant. For any gas volumes in excess of 18,000 Mcf/d of gas measured and delivered to the inlet flange of the gas treatment plant, Gateway will receive a transportation fee of $0.12 per Mcf measured and delivered from the outlet flange of the plant. This fee will remain in effect 36 months from the effective date of the MGP Agreement and shall be reduced to $0.10 per Mcf thereafter. After 60 months, this transportation fee shall be $0.10 per Mcf for all volumes delivered from the outlet flange of the plant.

The foregoing gathering, treatment and transportation price adjustments are inclusive of all costs and expenses to gather, separate, treat, dehydrate and transport natural gas produced and delivered from the Company s well(s).

The Company has committed to a three-well drilling program to facilitate the expansion of the gas treatment plant. The Company has drilled two of the three required wells to the Rodessa formation. The commitment requires the Company to commence the drilling of the third well sufficient to test the Smackover Formation (estimated to be encountered at approximately 18,000 feet) on or before September 30, 2008. It is estimated that the 18,000 foot well will cost $10 million to drill and complete. The Company has granted MGP a security interest in the Madisonville Field properties to secure the three well commitment. The security interest shall be subordinated to any third party lender in the event the Company secures future debt against the property. MGP has granted the Company a similar security interest in the gas treatment plant to secure its obligation to expand the treatment plant on a timely basis.

Madisonville Net Profits Interest GeoPetro s working interest is subject to a net profits interest in favor of an unrelated third party. The net profits interest is 12.5% (proportionately reduced) of the net operating profits until payout is achieved. After payout, the net

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profits interest increases to 30% (proportionately reduced). Payout, for purposes of the net profits interest, is defined and achieved at such time as GeoPetro has recouped from net operating cash flows its total net investment in the project plus a 33% cash on cash return.

The Cook Inlet Alaska CBM Project The Company entered into an agreement with Pioneer Oil Company, Inc. (Pioneer) dated April 20, 2005, wherein it acquired a 100% working interest (81% net revenue interest) in approximately 117,000 acres onshore in Cook Inlet, Alaska. The Company has subsequently acquired an additional 5,000 acres in this project. The terms provide for the Company to pay total consideration of $20 per acre, or approximately $2.3 million, for the leases. The Option provides that the Company will pay the total lease consideration in two installments. The Company paid the first installment totaling $1,068,063 on August 17, 2005 and has received assignment of the 100% working interest in the leases. Within three years from the date of receipt of legally sufficient assignment of the 100% working interest in the leases, the Company has the option to conduct a $2.5 million work program consisting of, but not limited to, a multiple test well drilling program on the leases over a three-year period, and, after completion of the work program and an evaluation of the results, to remit the final additional acreage consideration of $10 per acre for the leases. The agreement provides that if the Company fails to pay the lease consideration when due, fails to perform the work program or otherwise defaults under the agreement, it shall forfeit its interest and reassign the leases to Pioneer with no further liability to GeoPetro.

11. Subsequent Events:

Proceeds from Notes The Company issued three promissory notes in February 2007 as the following:

- The Company issued a $500,000 short term Note payable on February 1, 2007 with a maturity date of October 31, 2007. The note may be repaid at any time without penalty. The principal plus accrued interest on the note are due on the maturity date. In connection with the note, the Company paid a loan origination fee of $15,000 and granted a three-year exercisable warrant to purchase 25,000 Common Shares at $3.50 per share.

- The Company issued a $300,000 short term Note payable on February 6, 2007 with a maturity date of October 31, 2007. The note may be repaid at any time without penalty. The principal plus accrued interest on the note are due on the maturity date. In connection with the note, the Company paid a loan origination fee of $9,000 and granted a three-year exercisable warrant to purchase 15,000 Common Shares at $3.50 per share.

- The Company issued a $100,000 short term Note payable on February 1, 2007 with a maturity date of October 31, 2007. The note may be repaid at any time without penalty. The principal plus accrued interest on the note are due on the maturity date. In connection with the note, the Company paid a loan origination fee of $3,000 and granted a three-year exercisable warrant to purchase 5,000 Common Shares at $3.50 per share.

Note Extension On February 1, 2007, the Company received an extension of its note payable to Pine Hill Capital, LLC and the new maturity date is October 31, 2007. Under the agreement, the Company agreed to repay the entire remaining principal balance plus accrued interest on October 31, 2007. In the event this Note is not repaid by the maturity date, and unless an extension thereof is mutually agreed to, per the terms of the Note, the Company agreed that it shall dedicate 5% of its net cash flow from the Madisonville Project located in Madison County, Texas toward the unpaid Principal Amount and all accrued and unpaid interest thereon, until such amounts are paid in full. Net cash flow for purposes of this provision shall mean gross revenues received by the Company less royalties, production taxes and net profits interest expense. The Company has paid $80,000 accrued interest thru January 31, 2007. In connection with the extension, the Company paid a loan extension fee of $30,000 and granted a three-year exercisable warrant to purchase 50,000 Common Shares at $3.50 per share.

Warrants Issued On February 12, 2007, the Company issued a two-year exercisable no par voting common stock warrant to Rincon Energy, LLC to purchase 20,000 Common Shares at $3.50 per share. The purchase rights under the warrant has an expiration dates of February 12, 2009 unless terminated earlier in accordance with the stock warrant purchase agreement.

On February 28, 2007, the Company issued a two-year exercisable no par voting common stock warrant to Rincon Energy, LLC to purchase 5,000 Common Shares at $4.51 per share. The purchase rights under the warrant has an expiration date of February 28, 2009 unless terminated earlier in accordance with the stock warrant purchase agreement.

Related Party Promissory Note On February 12, 2007, Stuart J. Doshi, President and CEO, loaned $100,000 to the Company. The note bears interest at 8% annually and is payable on demand. The note plus accrued interest was repaid on March 28, 2007.

Note Receivable Extension On June 7, 2006, the Company loaned $1,000,000 to G. Carter Sedanoui, a 5% shareholder, evidenced by a short term promissory note payable to the Company with an original maturity date of March 31, 2007. On March 30, 2007, the Company extended the maturity date of the note to June 30, 2007.

Salary Increases On December 18, 2006, the independent members of the board of directors, acting on the recommendations of Stuart J. Doshi, the President and CEO, voted to increase the salaries of Messrs. Creel and Steinhauser, officers of the Company, to $163,200 annually effective January 1, 2007.

Conversion of Series AA Preferred Stock On March 28, 2007, all 1,890,710 of the Company s outstanding shares of Series AA Stock automatically converted into 1,890,710 shares of our common stock, no par value per share. Under the Company s Amended and Restated Articles of Incorporation, and as more fully described in Note 7, the Series AA stock automatically converts into common shares on a one-for-one share basis effective the first trading day after the reported high selling price for our common shares is at least $5.25 per share for any consecutive ten trading days, which condition was met on March 27, 2007. Dividends accrued on the Series AA Stock at a rate of $0.28 per annum, per share, while the Series AA Stock was outstanding. In 2006, dividends paid on the Series AA Stock totaled $529,400. Pursuant to the terms of the Series AA Stock, no dividends are payable for the first quarter of 2007.

12. UNAUDITED SUPPLEMENTARY OIL AND GAS RESERVE INFORMATION:

The following supplementary information is presented in compliance with United States Securities and Exchange Commission regulations and is not covered by the report of GeoPetro s independent registered public accountants. The information required to be disclosed for the years ended 2006, 2005 and 2004 in accordance with FASB Statement No. 69, Disclosures about Oil and Gas Producing Activities, is discussed below and is further detailed in the following tables.

The reserve quantities and valuations for fiscal 2006 are based upon estimates by MHA Petroleum Consultants. The reserve quantities and valuations for fiscal 2005 and 2004 are based upon estimates by Sproule Associates Inc. The proved reserves presented herein are located entirely within the United States. Proved reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e. prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions. Reservoirs are considered proved if economic productivity is supported by either actual production or a conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and (B) the immediately adjoining portions not yet drilled, but which can reasonably be judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

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

The estimates included in the following tables are by their nature inexact and are subject to changing economic, operating and contractual conditions. At December 31, 2006, all of GeoPetro s reserves are attributable to two producing wells and two shut-in wells. Other than the one producing well which has been on production since May 2003 and another well which was placed on production in March 2006, there is no other production history as of or subsequent to that date. Reserve estimates for these wells are subject to substantial upward or downward revisions after production commences and a production history is obtained. Accordingly, reserve estimates of future net revenues from production may be subject to substantial revision from year to year. Reserve information presented herein is based on reports prepared by independent petroleum engineers.

The assumptions used to compute the standardized measure are those prescribed by the Financial Accounting Standards Board and, as such, do not necessarily reflect GeoPetro s expectations for actual revenues to be derived from those reserves nor their present worth. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these are the basis for the valuation process.

The Company s proved reserves increased during 2006 due to revisions of previous estimates. This occurred due to the drilling of additional wells in the Company s Madisonville Project. The drilling and testing resulted in lowering the lowest known structural occurrence of hydrocarbons, thus extending the lower proved limit of the reservoir.

CHANGES IN QUANTITIES OF PROVED PETROLEUM AND NATURAL GAS RESERVES FOR THE YEARS ENDED DECEMBER 31 (UNAUDITED)

FACTORS	December 31, 2006 (MMcf)	December 31, 2005 (MMcf)	December 31, 2004 (MMcf)
Beginning of period	21,428	18,408	25,238
Extensions			
Improved Recovery			
Technical Revisions	5,122	4,763	(4,803)
Discoveries			
Acquisitions			
Dispositions			
Economic Factors			
Production	(1,950)	(1,742)	(2,027)
Year ended December 31,	24,600	21,428	18,408

PROVED RESERVES PRESENTED HEREIN ARE LOCATED ENTIRELY WITHIN THE UNITED STATES

	AS OF DECEMBER 31, 2006 (MMcf)	2005 (MMcf)	2004 (MMcf)
Proved developed	12,235	4,645	4,448
Proved developed non-producing	12,365	8,903	7,037
Proved undeveloped		7,881	6,923
Total	24,600	21,428	18,408

For purposes of the following disclosures, estimates were made of quantities of proved reserves and the periods during which they are expected to be produced. Future cash flows were computed by applying year-end prices to estimated annual future production from proved gas reserves. The average year-end prices for gas were as indicated below. Future development and production costs were computed by applying year-end costs to be incurred in producing and further developing the proved reserves. Future income tax expenses were computed by applying, generally, year-end statutory tax rates (adjusted for permanent differences, tax credits and allowances) to the estimated net future pre-tax cash flows. The discount was computed by application of a 10% discount factor. The calculations assume the continuation of existing economic, operating and contractual conditions. However, such arbitrary assumptions have not proven to be the case in the past. Other assumptions of equal validity could give rise to substantially different results.

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED PETROLEUM AND NATURAL GAS RESERVES (UNAUDITED)

	YEAR ENDED DECEMBER 31, 2006 (in thousands)	2005	2004
Future cash inflows	101,867	$ 162,459	$ 90,815
Future production costs	(37,783)	(60,176)	(30,240)
Future development costs	(1,075)	(6,560)	(4,860)
Future income taxes	(8,128)	(18,941)	(9,609)
Future net cash flows	54,882	76,782	46,106
10% annual discount	(8,341)	(13,293)	(8,455)
Standardized measure of discounted future net cash flows	$ 46,541	$ 63,489	$ 37,651

AVERAGE YEAR-END PRICE

2006 REPORT		2005 REPORT		2004 REPORT	
Gas ($/MMBtu)		**Gas ($/MMBtu)**		**Gas ($/MMBtu)**	
$	5.40	$	7.80	$	5.82

The following are the principal sources of changes in the standardized measure of discounted future net cash flows:

CHANGES IN THE STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS FROM PROVED PETROLEUM AND NATURAL GAS RESERVE QUANTITIES (Unaudited)
PROVED RESERVES ARE LOCATED ENTIRELY WITHIN THE UNITED STATES

	2006 (in $ thousands)	2005	2004
Standardized measure of discounted future net cash flows, beginning of period	$ 63,489	$ 37,651	$ 41,031
Sales of Oil and Natural Gas and NGLs Produced, Net of Production Costs, Taxes and Royalties	(4,480)	(6,228)	(4,454)
Net Change in Prices, Production Costs and Royalties Related to Future Production	(39,067)	20,399	6,335
Changes in Previously Estimated Development Costs Incurred During the Period	6,545	2,800	7,187
Changes in Estimated Future Development Costs	(1,075)	(4,410)	(4,382)
Net Change Resulting from Revisions in Quantity Estimates	1,074	18,524	(12,535)
Extensions	6,740		
Accretion of discount	8,019	3,765	4,103
Other	(4,656)	(1,296)	(2,868)
Net Change in Income Taxes	9,952	(7,716)	3,234
Standardized measure of discounted future net cash flows, end of period	$ 46,541	$ 63,489	$ 37,651

EXHIBIT INDEX

Exhibit Number	**Description**
3.1**	Amended and Restated Articles of Incorporation of GeoPetro Resources Company
3.2*	Amended and Restated Bylaws of the GeoPetro Resources Company
4.1**	Form of Warrant issued by GeoPetro Resources Company to various investors on various dates.
4.2**	Specimen Common Stock Certificate
10.1**	Joint Venture Agreement Bengara II, Dated January 1, 2000
10.2**	Production Sharing Contract Bengara II, Dated December 4, 1997
10.3**	Joint Venture Agreement Whicher Range, Dated October 28, 1996
10.4**	Exploration Permit #408, Dated July 2, 1997
10.5**	Madisonville Field Development Agreement Dated August 1, 2005
10.6**	Alaska Cook Inlet Option dated April 20, 2005
10.7**	The 2001 Stock Incentive Plan
10.8**	The 2004 Stock Option and Appreciation Rights Plan
10.9**	Stuart Doshi Employment Agreement, Dated July 28, 1997 (effective July 1, 1997) and amendments dated January 11, 2001, July 1, 2003, April 20, 2004, May 9, 2005, July 28, 2005 and January 30, 2006
10.10**	David Creel Employment Agreement, Dated April 28, 1998 and amendments dated June 15, 2000, May 12, 2003 and January 1, 2005
10.11**	J. Chris Steinhauser Employment Agreement, Dated June 19, 2000 and amendments dated December 12, 2002 and January 1, 2005
10.12**	Office Lease Agreement, Dated effective March 1, 2004
10.13**	Promissory Note to Pinehill Capital Inc., Dated January 31, 2006
10.14**	Form of Subscription Agreement for GeoPetro Resources Company stock executed by various investors on various dates.
10.15**	Promissory Note between GeoPetro Resources Company and G. Carter Sednaoui, Dated June 7, 2006
10.16**	Flow-Through Share Agreement between GeoPetro Resources Company and GeoPetro Canada Ltd., Dated March 30, 2006
10.17**	Form of Flow-Through Share Agreement between GeoPetro Resources Company and various investors, Dated March 30, 2006
10.18**	Promissory Notes between GeoPetro Resources Company and Stuart J. Doshi, various dates
10.19**	Shares Sale & Purchase Agreement Dated September 29, 2006
21.1*	List of Subsidiaries of GeoPetro
23.3*	Consent of MHA Petroleum Consultants
31.1*	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer.
31.2*	Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer.
32.1*	Certification of Chief Executive Officer and Chief Financial Officer of GeoPetro Resources Company pursuant to 18 U.S.C. § 1350.

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* Filed herewith

** Filed as the identically numbered exhibit to the Registration Statement on Form S-1, as amended (No. 333-135485), as filed with the Securities and Exchange Commission on June 30, 2006, and incorporated herein by reference.

Indicates a management contract or compensatory plan or arrangement.

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