GEOPETRO RESOURCES CO
Form 424B3
September 05, 2007
**Filed Pursuant To Rule 424(b)(3)**

**Registration No. 333-135485**

**PROSPECTUS**

**GEOPETRO RESOURCES COMPANY**

**16,499,991 shares of Common Stock**

**(No Par Value)**

| | |
|---|---|
| **The Offering:** | This offering relates to the possible sale, from time to time, by the shareholders listed on page 85 of this prospectus, the selling shareholders, of up to 16,499,991 shares of common stock of GeoPetro Resources Company. The shares of our common stock and securities which are exercisable for shares of our common stock which are being offered by this prospectus were issued to the selling shareholders pursuant to financing transactions. We will not receive any proceeds from sales by selling shareholders. The selling shareholders may sell all or a portion of their shares covered by this prospectus through public or private transactions at fixed prices, at prevailing market prices at the time of sale, at varying prices or negotiated prices, in negotiated transactions, or in trading markets for our common stock. We will bear all costs associated with this registration. |
| **Current Trading Market:** | 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 . On June 5, 2007, the last reported sale prices for our common stock on The Toronto Stock Exchange and in the U.S. on the American Stock Exchange were $2.95 and $4.35, respectively. |

**Investing in our common stock involves a high degree of risk. See Risk Factors Beginning on Page 6.**

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities, or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

**February 8, 2007**

**(As supplemented September 5, 2007, which supplement includes GeoPetro Resources Company s Quarterly Report on Form 10-Q for the second quarter of 2007, as filed with the Securities and Exchange Commission on August 14, 2007)**

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**You should rely only on the information contained in this prospectus. We have not authorized any other person to provide you with different information. If anyone provides you with different or inconsistent information, you should not rely on it. The selling shareholders are not making an offer to sell these securities in any jurisdiction where an offer or sale is not permitted. You should assume that the information appearing in this prospectus is accurate as of the date on the front cover of this prospectus only. Our business, financial condition, results of operations and prospects may have changed since that date.**

Unless otherwise specified or the context otherwise requires, all dollar amounts in this prospectus are expressed in U.S. dollars. Canadian dollars, when used, are expressed with the symbol CDN$ . Unless otherwise specified, where dollars are shown on a converted basis, the conversion is based upon an exchange ratio of CDN$1.00=$0.94, the exchange rate in effect on June 5, 2007, except for dollars set forth in or derived from the financial statements, where the exchange rate is derived as of the date of the financial statements.

**PROSPECTUS SUMMARY**

*This summary highlights selected information contained in greater detail elsewhere in this prospectus and does not contain all of the information that you should consider before investing in our common stock. You should read the entire prospectus carefully, especially the risks of investing in our common stock, which we discuss under Risk Factors and our consolidated financial statements and related notes. Unless otherwise indicated or required by the context, we, us, and our refer to GeoPetro Resources Company and its subsidiaries and predecessors. All financial data included in this prospectus has been prepared in accordance with generally accepted accounting principles in the United States. We have provided definitions for some of the natural gas and oil industry terms used in this prospectus in the Glossary on page A-1 of this prospectus. All dollar amounts appearing in this prospectus are stated in U.S. dollars unless specifically noted in Canadian dollars ( CDN$ ).*

**GEOPETRO RESOURCES COMPANY**

**Offices:** Our principal executive offices are located at One Maritime Plaza, Suite 700, San Francisco, CA 94111. Our telephone number is (415) 398-8186.

**Our Business:** We are an oil and gas company originally incorporated in the State of Wyoming in August 1994 but incorporated in California since June 1996. Our business is the exploration and the production of oil and natural gas reserves on a worldwide basis. We currently have projects in the United States, Canada, Indonesia and Australia. The projects encompass approximately 1.56 million gross (396,080 net) acres consisting of mineral leases, production sharing contracts and exploration permits that give us the right to explore for, develop and produce crude oil and natural gas. We have developed a proven cash-flow generating property in our Madisonville Project in Texas which we operate. Elsewhere, we have assembled a geographically diversified portfolio of exploratory and appraisal prospects which we believe have the potential for oil and natural gas reserves.

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

- Identify and pursue 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. Net present value means the estimated future net cash flows resulting from the sale of oil and gas less all of the operating and capital costs, discounted to present value using a 10% discount factor. Unrisked in this context means that we have not reduced the future net cash flows to account for the risk of finding and producing the reserves;
- perform geological, engineering and geophysical evaluations;
- gain control of key acreage;
- generate high quality drillable exploration and lower-risk appraisal and development prospects;
- retain a large working interest in those projects which involve low risk development, 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.

**Management:** Stuart J. Doshi, David V. Creel and J. Chris Steinhauser, the three members of our senior management team, have a combined experience of approximately 100 years in the oil and gas industry. This experience covers a broad range of activity both onshore and offshore, domestic and international and from company start-up to mature progression and company sale. This experience also covers the entire spectrum of the risk profile in any particular project from early stage exploration through full development and production.

| | |
|---|---|
| **Significant Risks:** | Our business faces significant risks. Acquisition, exploration and overhead costs are high and have resulted in substantial losses since inception. There is a limited public market for our common shares, which may hinder our ability to raise equity capital (if needed) on advantageous terms, and there is intense competition in our industry. See Risk Factors beginning on page 6 for a detailed discussion of these risks. |

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**Madisonville Field:** We own and operate a 100% working interest in the Madisonville Project in Madison County, Texas. We own working interests in approximately 2,668 gross and net acres of leases in the Rodessa Formation interval, as well as approximately 1,849 gross and net acres of leases as to depths below the Rodessa Formation interval. 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. In October 2001, we tested the Magness Well at rates of up to 20.8 MMcf/d. Production from this well commenced in May 2003 and stabilized at a rate of approximately 18 MMcf/d of raw gas as at October, 2003. In December 2004, the Fannin Well was drilled, completed and 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 (not producing). The production rate is presently restricted awaiting a planned expansion of the gas treatment plant to 68 MMcf/d treating capacity. The well reserves are being produced from the Rodessa formation existing at approximately 12,000 feet of depth. We entered into a long-term agreement with MGP, the gas treatment plant owner, to process Rodessa formation natural gas. MGP has made a binding commitment to expand the capacity of the treatment plant from 18 MMcf/d to 68 MMcf/d. MGP is jointly owned by JPMorgan Partners and Bear Cub Investments LLC. Gateway Processing Company ( Gateway ) owns and operates an approximately nine-mile sales pipeline with an estimated capacity of approximately 70 MMcf/d to transport the natural gas from the Madisonville Field to two major pipelines in the area.

**Alaska CBM:** We entered into an agreement with Pioneer Oil Company, Inc. dated April 20, 2005, wherein we acquired a 100% working interest, 81% net revenue interest, in 122,174 acres onshore in Cook Inlet, near Anchorage, Alaska. Preliminary log analysis indicates the lease blocks may contain coal bed methane, CBM , reserves as well as conventional accumulations of natural gas in Tertiary sandstones. Please see the glossary on page A-1 for definitions of terms. 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. We may reduce exploration risk by finding participants to pay most or all of the money expended towards acquisition and initial exploration.

**Lokern Project:** We have a 100% working interest in 1,280 acres over a prospect in Kern County, California. An oil and gas prospect has been identified using reprocessed seismic. Please see the glossary on page A-1 for definitions of terms.

**Reef Project:** We, through our wholly-owned subsidiary, GeoPetro Canada Ltd. ( **GeoPetro Canada** ) have acquired seismic data and plan to participate in exploratory drilling targeting reef prospects located in the central Alberta basin, Canada, approximately 100 miles northeast of Calgary. We have a 56.25% working interest in 2,560 leased acres in the central Alberta basin**.**

**Bengara (II) PSC:** We, through our 12% ownership interest of Continental-GeoPetro (Bengara II) Ltd., a British Virgin Islands corporation ( **C-G Bengara** ) have a 12% interest in the Bengara (II) PSC Block in East Kalimantan, Indonesia (the **Bengara Block** ) which covers approximately 900,000 gross (108,000 net) acres. Two wells have been drilled in this block since 1938 and one of these resulted in a natural gas discovery, testing 19.5 MMcf/d together with 600 bbls condensate per day. Please see the glossary on page A-1 for definitions of terms. Elsewhere in the block, a large number of prospects and leads have been identified based primarily on seismic data. On September 29, 2006, we sold to CNPCHK (Indonesia) Limited ( CNPC ) 70% of our shareholding in the Company s Continental-GeoPetro (Bengara-II) Ltd. subsidiary and our interest in the Bengara (II) 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.

**THE OFFERING**

| | |
|---|---|
| **Common stock that may be offered by the selling shareholders:** | 16,499,991 shares(1) |
| **Common stock to be outstanding immediately after this offering:** | 34,773,573 shares(2) |
| **Use of proceeds:** | We will not receive any proceeds from the sales of our common stock by the selling shareholders. |
| **Risk factors:** | See Risk Factors and other information included in this prospectus for a discussion of some of the factors you should consider before deciding to purchase shares of our common stock. |

**American Stock Exchange Symbol: GPR**

***Toronto Stock Exchange Symbol: GEP.s***

(1) Includes 10,789,493 shares of common stock, 1,750,498 shares of common stock issuable upon exercise of warrants and 3,960,000 shares of common stock issuable upon exercise of options.

(2) Assumes the sale by the selling stockholders of all the shares of common stock available for resale under this prospectus.

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**SUMMARY CONSOLIDATED FINANCIAL DATA**

The following table sets forth certain of our summary consolidated financial data for the periods indicated. 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 prospectus. 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 prospectus. You should read this information together with the consolidated financial statements and the notes to those statements appearing elsewhere in this prospectus and the information under Selected Consolidated Financial Data and Management s Discussion and Analysis of Financial Condition and 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 ) |

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**RISK FACTORS**

An investment in our common stock involves a high degree of risk. You should carefully consider the risks described below together with all of the other information included in this prospectus before making an investment decision. If any of the possible adverse events described below actually occurs, our business, results of operations and financial condition could suffer. Under these circumstances, the market price of our common stock could decline and you could lose all or part of your investment.

**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 CNPCHK (Indonesia) Limited ( CNPC ), 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 prospectus 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 CNPC, 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 prospectus, 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 this Offering and 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 prospectus, 1,865,498 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 large numbers of shares of our common stock eligible for sale following this offering 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.*** *Following this offering, 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. These include shares of our common stock sold in this offering, as well as shares of common stock outstanding after this offering which are available for sale in public markets pursuant to Rule 144 or Rule 701 promulgated under the Securities Act.*

***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.***

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**CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS**

Most of the matters discussed within this prospectus include forward-looking statements on our current expectations and projections about future events. Words such as may, should, potential, continue, expect, anticipate, intend, plan, believe, seek, estimate, and similar intended to identify such forward looking statements. These statements are based on our current beliefs, expectations, and assumptions and are subject to a number of risks and uncertainties and, therefore, actual results and events may vary significantly from those discussed in the forward-looking statements. These risks and uncertainties include those noted in Risk Factors above. Other factors besides those listed here could adversely affect us.

These forward-looking statements may include, among other things, statements relating to the following matters:

- the level of oil and gas reserves that can be extracted at any of our projects;
- our ability to extract reserves at commercially attractive prices;
- our ability to compete against companies with much greater resources than us:
- identified drilling locations;
- exploration and development drilling prospects, inventories, projects and programs;
- financial strategy;
- production;
- lease operating expenses, general and administrative costs and finding and development drilling costs;
- future operating results; and
- plans, objectives, expectations and intentions.

We undertake no obligation to update publicly any forward-looking statements, whether as a result of new information, future events or otherwise, except to the extent we are required to do so by law.

You should not unduly rely on these forward-looking statements in this prospectus as they speak only as of the date of this prospectus. Except as required by law, we undertake no obligation to publicly release any revisions to these forward-looking statements to reflect events or circumstances occurring after the date of this prospectus or to reflect the occurrence of unanticipated events. See the information under the heading Risk Factors in this prospectus for some of the important factors that could affect our financial performance or could cause actual results to differ materially from estimates contained in forward-looking statements.

**USE OF PROCEEDS**

We will not receive any proceeds from the sale of our common stock by the selling shareholders; however if all warrants and options to acquire our common stock being registered hereunder were to be exercised, we will realize cash proceeds of approximately $13,931,169, 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 $13,931,169 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.

**DILUTION**

On March 28, 2007, all outstanding shares of our Series AA 8% Convertible Preferred Stock converted to common stock. If the conversion had occured on December 31, 2006, rather than on March 28, 2007, the net tangible book value of our common stock on December 31, 2006 would have been approximately $35,408,294, or approximately $1.21 per share. Net tangible book value per share represents the amount of our total tangible assets, less our total liabilities, divided by the total number of shares of our common stock outstanding. The number of shares of our common stock outstanding may be increased if we issue additional shares, upon exercise of warrants or options, or payment of stock dividends on our common stock, and, to the extent warrants and options are exercised for cash, the net tangible book value of our common stock may increase or decrease depending on the exercise price thereof. Since we will not receive any of the proceeds from the sale of common stock sold by the selling shareholders under this prospectus, the net tangible book value of our common stock will not be increased as a result of such sales, nor will the number of shares outstanding be affected by such sales. If the warrants and options are exercised for cash to purchase 5,943,105 shares of our common stock underlying them, which are included in this registration statement, the net tangible book value of our common stock would be approximately $49,371,413 or $1.40 per share, including the effect of the conversion of all outstanding shares of our Series AA Stock, but excluding the effect of any other transactions occurring after December 31, 2006. However, any dilution to new investors will represent the difference between the amount per share paid by purchasers of shares of our common stock from the selling shareholders in this offering and the net tangible book value per share of our common stock at the time of purchase of shares pursuant to exercise of such warrants and options.

**MARKET PRICE OF COMMON STOCK**

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 . On June 5, 2007, the last reported sale prices for our common stock on the American Stock Exchange and Toronto Stock were $4.35 and $2.95, 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** | | | | | | |
| Second Quarter through June 5, 2007 | $ 4.75 | $ 3.81 | $ 2.85 | $ 2.30 | N/A | N/A |
| First Quarter | $ 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 June 5, 2007, there were 509 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.

**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.

**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 prospectus. 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 prospectus. 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 prospectus. 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 ) |

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**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 prospectus. 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 prospectus, 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 prospectus after the date of this prospectus, 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 and the Fannin #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) |
| Proceeds from promissory notes | 1,900,000 | | 2,075,000 |
| Payment of loan fee | (30,000) | | |
| Repayment of promissory notes | (900,000) | (4,781,807) | (1,158,569) |
| Deferred offering costs | (1,213,789) | (730,906) | (150,255) |
| 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.

**Quantitative and Qualitative Disclosures About Market Risk**

*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 $700,000 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.

**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

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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.

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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 prospectus. 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.

**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

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- **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 a report with the U.S. Department of Energy in May 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. We filed a report with the Alberta Securities Commission on March 30, 2007 that included total proved reserves inclusive of royalties and net profits interests as of December 31, 2006 totaling 43,517 MMcf. The total net proved reserves, excluding royalties and net profits interests, as of December 31, 2006 was 24,600 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 |

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*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 | | | | | | |