GASTAR EXPLORATION LTD
Form 424B3
January 04, 2006
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Registration No. 333-127498

PROSPECTUS

23,085,160 Shares

Gastar Exploration Ltd.

Common Shares

This prospectus relates to the offer and sale, from time to time, of up to 23,085,160 common shares of Gastar Exploration Ltd., an Alberta corporation, held by or issuable to the selling shareholders listed on page 78 of this prospectus. The common shares being offered by the selling shareholders are outstanding, issuable upon conversion of the convertible debentures, issuable pursuant to outstanding subscription receipts and upon exercise of warrants. See Selling Shareholders . Gastar will not receive any proceeds from the sale of the shares by the selling shareholders. All the proceeds from the sale of shares will be for the respective account of each selling shareholder.

For a description of the plan of distribution of the shares, please see page 88 of this prospectus.

Our common shares are listed on the Toronto Stock Exchange under the symbol YGA (in the U.S., YGA.TO) and are approved for listing, and may trade in the United States, on the American Stock Exchange under the symbol GST . On December 30, 2005, the last reported sale prices for our common shares on The Toronto Stock Exchange and in the United States over-the-counter market were CDN$4.25 and $3.63, respectively.

Investing in our common shares involves risks. Please read Risk Factors beginning on page 7.

This prospectus has not been filed in respect of, and will not qualify, any distribution of the common shares in any province or territory of Canada.

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.

January 4, 2006

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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. We 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 = $0.8546, the exchange rate in effect on December 30, 2005, 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.

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PROSPECTUS SUMMARY

This summary highlights information contained elsewhere in this prospectus. You should read the entire prospectus carefully, including the detailed information contained under the heading Risk Factors , consolidated financial statements and the accompanying notes to those financial statements included elsewhere in this prospectus. Unless otherwise indicated or required by the context, (i) we , us , and our refer to Gastar Exploration Ltd. and its subsidiaries and predecessors, (ii) Geostar acquisition refers to our June 2005 acquisition from Geostar Corporation (Geostar) of additional reserves and working interests in the Powder River Basin and in East Texas, (iii) convertible debentures refers to our $30.0 million principal amount of 9.75% convertible senior unsecured debentures, (iv) warrants refers to the warrants to purchase common shares issued to investors in connection with certain financing transactions or to our placement agents in connection with the offering of convertible debentures and certain other subordinated notes as partial compensation for their services, (v) senior secured notes refers to our $73.0 million principal amount of senior secured notes issued in 2005, (vi) all dollar amounts appearing in this prospectus are stated in U.S. dollars unless specifically noted in Canadian dollars (CDN$), and (vii) 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 of Natural Gas and Oil Terms on page A-1 of this prospectus.

Gastar Exploration Ltd.

Our Business

We are an independent energy company engaged in the exploration, development and production of natural gas and oil in the United States and Australia. Our principal business activities include the identification, acquisition, and subsequent exploration and development of natural gas and oil properties. Our emphasis is on prospective deep structures identified through seismic and other analytical techniques as well as unconventional natural gas reserves, such as coal bed methane. Our current areas for natural gas or oil activities are:

- Deep Bossier play in East Texas;
- Powder River Basin in Wyoming and Montana;
- Gunnedah Basin in New South Wales, Australia;
- Gippsland Basin in Victoria, Australia;
- Appalachian Basin in West Virginia;
- San Joaquin Basin in California; and
- Cherokee Basin in Southeast Kansas.

We currently are pursuing conventional natural gas exploration in the Deep Bossier play in the Hilltop area in East Texas and the Appalachian Basin in West Virginia. As of September 30, 2005, we had leases on approximately 51,800 gross acres (34,000 net) in Texas and approximately 26,700 gross acres (13,300 net) in Appalachia. For the nine months ended September 30, 2005, our daily net production from the Hilltop area averaged approximately 6.9 MMcfed, and from the Appalachian Basin, it averaged 0.1 MMcfed.

In our coal bed methane, or CBM, projects, we use industry technologies to assist us in developing commercial natural gas production from known coal beds. Our primary CBM properties are in the United States in the Powder River Basin and in the Gunnedah and Gippsland Basins of Australia. As of September 30, 2005,

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our acreage position in the Powder River Basin was approximately 55,800 gross acres (21,600 net), and our Australian acreage totaled approximately 3.4 million gross acres (1.8 million net). For the nine months ended September 30, 2005, our average net daily production from our CBM properties in the Powder River Basin was approximately 2.6 MMcfed. Exploration and long term production testing on our Australian CBM properties is currently underway. Thus, we currently have no natural gas sales from our Australian CBM properties.

We have not been profitable since we started our business. We incurred net losses of $12.8 million and $4.9 million for the years ended December 31, 2004 and 2003, respectively. We have incurred a net loss of $20.9 million for the nine months ended September 30, 2005. Our capital has been employed in an increasingly expanding natural gas and oil exploration and development program with the focus on finding significant natural gas an oil reserves and producing from them over the long term rather than focusing on achieving immediate net income. The uncertainties described in the Risk Factors section may impede our ability to ultimately find, develop and exploit natural gas and oil reserves. As a result, we may not be able to achieve or sustain profitability or positive cash flows from operating activities in the future.

Our Strategy

Management believes that:

- Natural gas is an environmentally friendly fuel that will be increasingly valued in the United States and Australia;
- CBM projects provide us with lower risk exposure to long-lived natural gas production and reserves;
- We have made a significant natural gas discovery in the Deep Bossier play in the Hilltop area of East Texas that will require additional exploration and development;
- We have the ability to assemble the technical and commercial resources needed to pursue these potential projects; and
- Our successful development of one or more large potential natural gas projects will create substantial shareholder value.

Based on these beliefs, we have pursued a strategy that includes:

- Accelerating exploration and development drilling on our Deep Bossier play in East Texas;
- Combining lower risk CBM projects, such as the Powder River Basin and Australia, with higher risk conventional natural gas exploration;
- Assembling a portfolio of high-potential natural gas exploration and development projects in East Texas and in the Appalachian Basin; and

Limiting capital commitments and reducing risk by maintaining financial flexibility through accessing various sources of capital and monetizing certain assets through joint venture arrangements with industry participants.

Recent Developments

Issuance of Senior Secured Notes and Common Shares. On June 17, 2005, we completed the private placement of $63.0 million in principal amount of senior secured notes and 1,217,269 common shares. The notes bear interest at three month LIBOR plus 6% and mature on June 18, 2010. LIBOR is an abbreviation for London Interbank Offered Rate , and is the interest rate offered by a specific group of London banks for U.S. dollar deposits of a stated maturity. We also issued to the purchasers of the notes, for no additional consideration, subscription receipts entitling the holders to receive additional common shares in CDN$4.5 million increments

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on each of the six, twelve and eighteen-month anniversaries of the original note issuance date valued on a five-day weighted average trading price immediately prior to the date of issuance.

On September 19, 2005, we issued to the holders of our senior secured notes an additional $10.0 million of senior secured notes on substantially the same terms as the original June 2005 private placement, including the issuance of 206,354 common shares to the note holders. The common shares issued in the transaction represented an aggregate value of CDN$714,286 based upon the five day weighted average trading price of CDN$3.4615 per share for the five trading days immediately prior to closing. In connection with the sale of the additional notes, we issued subscription receipts to the purchasers of the notes, for no additional consideration, entitling the holders to receive additional common shares in CDN$714,286 increments on each of the six, twelve and eighteen-month anniversaries of the closing date, valued on a five day weighted average trading price immediately prior to the date of issuance.

On December 19, 2005, pursuant to the Senior Secured Notes, we issued to the Senior Secured Notes holders, for no additional consideration, an additional 1,082,105 common shares valued at CDN$4.1586, the five day weighted average trading price immediately prior to the date of issuance. Such shares were issued to the purchasers of the Senior Secured Notes on the six month anniversary of the original $63.0 million note issuance pursuant to subscription receipts.

We have the right, exercisable quarterly to June 16, 2007, to require the original purchaser of the senior secured note to purchase additional notes in an amount limited to an additional $10.0 million in principal. If additional notes are issued, the purchasers will also be entitled to receive, for no additional consideration, additional common shares and subscription receipts on similar terms as those issued with the original notes in a pro rata amount based on the additional principal amount of the notes. To issue these additional notes, we must meet certain requirements, as set forth in the senior secured notes. For additional information on the requirement to issue additional notes, see Description of Indebtedness Senior Secured Notes .

Geostar Acquisition. Concurrently with the private placement of senior secured notes, we closed the acquisition of additional leasehold and working interest properties from Geostar in the Hilltop area of East Texas and in the Powder River Basin of Wyoming and Montana. We paid a total of $68.5 million for the interests acquired from Geostar consisting of $30.5 million in cash, 1,650,133 common shares valued at CDN$4.50 per share and $32.0 million in unsecured subordinated notes maturing on January 31, 2006. The acquisition increased our working interest position in the Hilltop area to an average of over 90% and gave us operational control of the properties. The acquisition of additional Powder River Basin interests provides us with a larger interest in properties currently being developed through an existing joint venture.

On August 11, 2005, we executed an agreement with Geostar whereby the Geostar $32.0 million unsecured subordinated note was cancelled. In conjunction with the note cancellation, we agreed to issue Geostar 6,373,694 common shares, calculated by dividing $17.0 million by an assumed value of CDN$3.25 per share and a new unsecured subordinated note for $15.0 million. The new Geostar note bears interest, payable monthly commencing February 15, 2006, at three-month LIBOR plus 4.5% and matures November 15, 2006. The note requires monthly principal payments of $1.5 million commencing February 15, 2006 and continuing for nine months thereafter with a final principal payment of $1.5 million due on November 15, 2006. We may elect to pay interest in kind through the issuance of additional notes with such notes maturing on January 15, 2007. We may also be required to issue additional common shares to Geostar in the future based on the results of East Texas drilling, as described in Certain Relationships and Related Party Transactions . Pursuant to the terms of the Geostar agreement, we will utilize a portion of the proceeds of the Chesapeake Energy Corporation transaction to pay the Geostar note in full. See Transaction with Chesapeake Energy Corporation below. For additional information on the Geostar acquisition and our activities in the East Texas Basin, see Business Natural Gas and Oil Operations .

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Transaction with Chesapeake Energy Corporation. On November 4, 2005, we closed a transaction with Chesapeake Energy Corporation whereby Chesapeake:

- Acquired approximately 27.2 million newly issued common shares from us equal to 19.9% of its then outstanding common shares for $76.0 million (CDN$89.9 million) in cash or CDN$3.31 per share, before fees and expenses;

- Acquired a 33.33% working interest in our Deep Bossier play in the Hilltop prospect area of Leon and Robertson Counties of East Texas; and

- Formed an area of mutual interest to explore jointly in 13 counties in East Texas.

Chesapeake agreed to pay approximately $7.8 million, before fees and expenses, to acquire the shares described above and to pay a disproportionate amount off future drilling costs described below, in exchange for an undivided 33.33% of our leasehold working interests in the Deep Bossier Hilltop prospect, less and except 160 acres surrounding each of our existing well bores. Chesapeake agreed to pay 44.44% of the drilling costs through casing point in the first six wells drilled by the parties in the Hilltop prospect to a depth sufficient to test the Deep Bossier formation (an approximate depth of 19,000 feet) in order to earn its 33.33% leasehold working interest.

Pursuant to the terms of the Geostar agreement, we will utilize a portion of the proceeds of the Chesapeake transaction to pay the Geostar note in full.

Common Share Placement. On June 30, 2005, we completed a private placement of 6,617,736 common shares at CDN$3.31 per share. The estimated net proceeds from this placement were $16.4 million (CDN$20.5 million), after deducting placement fees and expenses.

Corporate Information

We are a Canadian corporation that is subsisting under the *Business Corporations Act* (Alberta). Our principal office is located at 1331 Lamar Street, Suite 1080, Houston, Texas 77010, and our telephone number is (713) 739-1800. Our website address is http://*www.gastar.com*. Information on our website or about us on any other website is not incorporated by reference into this prospectus and does not constitute a part of this prospectus.

We were originally incorporated in 1987 under the name CopperQuest Inc. pursuant to the *Business Corporations Act* (Ontario). On May 16, 2000, we continued from the Province of Ontario into the Province of Alberta to subsist pursuant to the *Business Corporations Act* (Alberta), changed our name to Gastar Exploration Ltd. and, pursuant to a reverse takeover, acquired 1075191 Ontario Ltd. and its resource property in Wyoming. Our common shares were quoted on the Canadian Dealing Network Inc. and its successor, the Canadian Venture Exchange, from June 5, 2000 until January 24, 2002 when our common shares began trading on The Toronto Stock Exchange under the symbol YGA (in the U.S., YGA.TO). Our common shares have also been approved for listing on the American Stock Exchange and are expected to trade on that exchange shortly after the date of this prospectus under the symbol GST .

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THE OFFERING

Common shares to be offered by the selling shareholders shares	23,085,160
Use of proceeds	We will not receive any of the proceeds from the sale of the shares by the selling shareholders. All the proceeds from the sale of shares will be for the respective accounts of the selling shareholders.
Exchange listing	Our common shares are listed on the Toronto Stock Exchange under the symbol YGA (in the U.S., YGA.TO) and are approved for listing, and may trade in the United States, on the American Stock Exchange under the symbol GST .

This prospectus relates to the offer and sale, from time to time, of the common shares by selling shareholders. Pursuant to various agreements entered into in connection with the offering of our securities, we are required to register for resale certain of our common shares that are either now outstanding or will be issued upon exercise of certain warrants or conversion of our convertible debentures or common shares that we have issued, or committed to issue pursuant to subscription receipts. We are also offering the opportunity to participate in the registration statement to other holders of some of our restricted securities. Shares covered in the registration will include 10,021,402 outstanding common shares currently held by some holders and additional common shares to be issued in the future in connection with the following:

The exercise of outstanding warrants to purchase 2,992,261 common shares;

The conversion of our convertible debentures, which are convertible into 6,488,584 common shares; and

The issuance of an estimated 3,582,913 common shares that we have committed to issue pursuant to subscription receipts on future dates for no additional consideration to purchasers of our senior secured notes.

For additional information about our warrants, see Description of Capital Stock . For additional information about our convertible debentures, our senior secured notes and the shares issuable in connection with our senior secured notes, see Description of Indebtedness .

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SUMMARY CONSOLIDATED FINANCIAL DATA

The following table presents summary historical financial data as of and for the periods indicated. The summary consolidated financial data as of and for the years ended December 31, 2004, 2003 and 2002 are derived from our audited consolidated financial statements. The summary consolidated financial data as of September 30, 2005 and for the nine months ended September 30, 2005 and 2004 are derived from our unaudited consolidated financial statements.

Our unaudited consolidated financial statements include, in the opinion of management, all adjustments, consisting only of normal, recurring adjustments, that management considers necessary for a fair statement of the results of those periods. Our historical results are not necessarily indicative of results to be expected in any future period and the results for the nine months ended September 30, 2005 should not be considered indicative of results expected for the full 2005 fiscal year.

You should read the following summary consolidated financial data in conjunction with our audited and unaudited consolidated financial statements and the accompanying notes included elsewhere in this prospectus and the sections of this prospectus entitled, Selected Historical Financial and Operational Information and Management s Discussion and Analysis of Financial Condition and Results of Operations .

	As of and for the Nine Months Ended September 30,		As of and for the Years Ended December 31,		
	2005	2004	2004	2003	2002
	(Unaudited)				
	(in thousands, except per share amounts)				
Consolidated Statement of Loss Data:					
Revenues	$ 17,496	$ 1,688	$ 6,059	$ 1,461	$ 783
Operating loss before interest expense	$ (10,426)	$ (1,984)	$ (9,587)	$ (2,368)	$ (2,657)
Net loss	$ (20,921)	$ (3,391)	$ (12,776)	$ (4,947)	$ (4,599)
Basic and diluted loss per share	$ (0.17)	$ (0.03)	$ (0.12)	$ (0.05)	$ (0.05)
Shares used in the calculation of basic and diluted loss per share	121,205	110,709	111,374	104,958	98,618
Consolidated Balance Sheet Data:					
Net natural gas and oil properties	$ 158,391		$ 56,556	$ 35,791	$ 34,457
Total assets	$ 178,317		$ 84,442	$ 38,757	$ 36,034
Long term liabilities	$ 108,861		$ 60,668	$ 10,554	$ 12,291
Total shareholders equity	$ 47,877		$ 21,976	$ 23,669	$ 22,430
Production Data:					
Production:					
Natural gas (MMcf)	2,615	353	1,108	385	393
Oil (MBbl)	1.6	1.1	1.8	1.0	3.1
Oil Natural gas equivalents (Mmcfe)	2,624	359	1,119	391	412
Natural gas (MMcfd)	9.6	1.3	3.0	1.1	1.1
Oil (MBod)	0.0	0.0	0.0	0.0	0.0
Oil Natural gas equivalents (Mmcfed)	9.6	1.3	3.1	1.1	1.1

Average Sales Prices:

Natural gas ($ per Mcf)	$ 6.67	$ 4.67	$ 5.40	$ 3.72	$ 1.33
Oil ($ per Bbl)	$ 50.19	$ 37.75	$ 40.08	$ 27.89	$ 20.15

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RISK FACTORS

In addition to the other information set forth elsewhere in this prospectus, you should carefully consider the following material risk factors associated with our business and the offering of shares of our common stock when evaluating Gastar. An investment in Gastar will be subject to risks inherent in our business. The trading price of the common shares of Gastar will be affected by the performance of our business relative to, among other things, competition, market conditions and general economic and industry conditions. The value of an investment in Gastar may decrease, resulting in a loss.

Risks Related to our Business

Natural gas and oil prices are volatile and a decline in natural gas and oil prices can significantly affect our financial condition.

The success of our business greatly depends on market prices of natural gas and oil. The higher market prices are, the more likely it is that we will be financially successful. On the other hand, declines in natural gas or oil prices may materially adversely affect our financial condition, profitability and liquidity. Lower prices also may reduce the amount of natural gas or oil that we can produce economically.

Natural gas and oil are commodities whose prices are set by broad market forces. Historically, the natural gas and oil markets have been volatile. We do not see any reason why natural gas or oil prices will not continue to be volatile in the future. Prices for natural gas and oil are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for natural gas or oil, market uncertainty and a variety of additional factors that are beyond our control. These factors include:

- The domestic and foreign supply of natural gas and oil;
- Overall economic conditions;
- Weather conditions;
- Political conditions in the Middle East and other oil producing regions;
- Domestic and foreign governmental regulations;
- The level of consumer product demand; and
- The price and availability of alternative fuels.

Rising demand for natural gas to fuel power generation and to meet increasingly stringent environmental requirements has led some observers to believe that long term demand for natural gas is increasing.

Our success depends on natural gas prices in the specific areas where we operate, and these prices may be lower than prices at major markets.

Even though overall natural gas prices at major markets, such as Henry Hub in Louisiana, may be high, regional natural gas prices may move somewhat independent of broad industry price trends. Because some of our operations are located outside major markets, we are directly impacted by regional natural gas prices regardless of Henry Hub or other major market pricing. For example, surplus natural gas supplies relative to available transportation in the Powder River Basin in 2002 caused local natural gas prices to be much less than national natural gas prices, and we, therefore, were unable to take advantage of those higher national natural gas prices. Low natural gas prices in any or all of the areas where we operate would negatively impact our financial condition and results of operations.

Natural gas and oil reserves are depleting assets and the failure to replace our reserves would adversely affect our production and cash flows.

Our future natural gas and oil production depends on our success in finding or acquiring new reserves. If we fail to replace reserves, our level of production and cash flows would be adversely impacted. Production from natural gas and oil properties decline as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our total proved reserves will decline as reserves are produced unless we conduct other successful exploration and development activities or acquire properties containing proved reserves, or both. Our ability to make the necessary capital investment to maintain or expand our asset base of natural gas and oil reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. We may not be successful in exploring for, developing or acquiring additional reserves. If we are not successful, our future production and revenues will be adversely affected.

Exploration is a high risk activity, and our participation in drilling activities may not be successful.

Our future success will largely depend on the success of our exploration drilling program. Participation in exploration drilling activities involves numerous risks, including the risk that no commercially productive natural gas or oil reservoirs will be discovered. The cost of drilling, completing and operating wells is often uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- Unexpected drilling conditions;
- Blowouts, fires or explosions with resultant injury, death or environmental damage;
- Pressure or irregularities in formations;
- Equipment failures or accidents;
- Adverse weather conditions;
- Compliance with governmental requirements and laws, present and future; and
- Shortages or delays in the availability of drilling rigs and the delivery of equipment.

We use available seismic data to assist in the location of potential drilling sites. Even when properly used and interpreted, 2-D and 3-D seismic data and other visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators. They do not allow the interpreter to know conclusively if hydrocarbons are present or economically producible. Poor results from our drilling activities would materially and adversely affect our future cash flows and results of operations. In addition, using seismic data and other advanced technologies involves substantial upfront costs and is more expensive than traditional drilling strategies, and we could incur losses as a result of these expenditures.

We have incurred significant net losses since our inception and may incur additional significant net losses in the future.

We have not been profitable since we started our business. We incurred net losses of $12.8 million and $4.9 million for the years ended December 31, 2004 and 2003, respectively. We have incurred a net loss of $20.9 million for the nine months ended September 30, 2005. Our capital has been employed in an increasingly expanding natural gas and oil exploration and development program with the focus on finding significant natural gas an oil reserves and producing from them over the long term rather than focusing on achieving immediate net income. The uncertainties described in this section may impede our ability to ultimately find, develop and exploit natural gas and oil reserves. As a result, we may not be able to achieve or sustain profitability or positive cash flows from operating activities in the future.

Our level of indebtedness reduces our financial and operational flexibility, and our level of indebtedness may increase.

As of September 30, 2005, the principal amount of our total indebtedness was $124.1 million. Our level of indebtedness affects our operations in several ways, including the following:

A significant portion of our cash flow must be used to service our indebtedness;

A high level of debt increases our vulnerability to general adverse economic and industry conditions;

- The covenants contained in the agreements governing our outstanding indebtedness limit our ability to borrow additional funds, dispose of assets, pay dividends, sell common shares below certain prices and make certain investments;

- Although we have the ability, subject to the limitations specified in the agreement, to borrow an additional $10.0 million of senior secured notes through June 2007, the terms of our senior secured notes prohibit us from borrowing funds senior or pari passu to the senior secured notes and may limit our ability to borrow subordinated funds;

- Our debt covenants may also affect our flexibility in planning for, and reacting to, changes in the economy or in our industry;

- A high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions or general corporate purposes;

- A default under our senior loan covenants could result in required principal payments that we may not be able to meet, resulting in higher penalty interest rates and/or debt maturity acceleration; and

- The Geostar agreement requires that we utilize a portion of the proceeds of the Chesapeake transaction to repay the $15.0 million Geostar note in full.

We may incur additional debt, including significant additional secured indebtedness, in order to make future acquisitions or to develop our properties. A higher level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, natural gas and oil prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control. We may not be able to generate sufficient cash flow to pay the interest on our debt and future working capital, borrowings or equity financing may not be available to pay or refinance such debt. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions, the value of our assets and our performance at the time we need capital.

If we are unable to raise substantial amounts of additional capital, we may not be able to maximize our business plan.

In order to maximize our business plan, we will need to raise substantial amounts of new capital. If we experience difficulties in raising equity or debt capital, we may be required to scale back our business plan by limiting acquisitions and our drilling and development program. Restrictions imposed under our senior secured notes may limit our ability to borrow additional funds.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions could materially affect the quantities and present values of our reserves.

The process of estimating natural gas and oil reserves is complex. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves.

There are many uncertainties inherent in estimating natural gas and oil reserves and their values, many of which are beyond our control. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas or oil that cannot be measured in an exact manner. Estimates of economically recoverable natural gas or oil reserves and of future net cash flows necessarily depend on many variables and assumptions, such as:

Historical natural gas or oil production from that area, compared with production from other producing areas;

- The assumed effects of regulations by governmental agencies;
- Assumptions concerning future prices;
- Assumptions concerning future operating costs;
- Assumptions concerning severance and excise taxes; and
- Assumptions concerning development costs and workover and remedial costs.

Any of these assumptions could vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of natural gas or oil attributable to any particular group of properties, classifications of those reserves based on risk recovery and estimates of the future net cash flows expected from them prepared by different engineers, or by the same engineer at different times, may vary substantially. Because of this, our reserve estimates may materially change at any time.

You should not consider the present values of estimated future net cash flows referred to in this prospectus to be the current market value of the estimated reserves attributable to our properties. The estimated discounted future net cash flows from proved reserves are generally based on prices and costs in effect when the estimate is made. However, actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by factors such as:

- The amount and timing of actual production, supply and demand for natural gas or oil;
- Curtailments or increases in consumption by natural gas or oil purchasers;
- Changes in governmental regulations or taxation; and
- The timing of both production and expenses in connection with the development and production of natural gas or oil properties.

In this prospectus, the net present value of future net revenues is calculated using a 10% discount rate. This rate is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our reserves or the natural gas and oil industry in general.

The imprecise nature of estimating proved natural gas and oil reserves, future downward revisions of proved reserves and increased drilling expenditures without current additions to proved reserves may lead to write downs in the carrying value of our natural gas and oil properties.

Due to the imprecise nature of estimating natural gas and oil reserves as well as the potential volatility in natural gas and oil prices and their effect on the carrying value of our natural gas and oil properties, write downs in the future may be required as a result of factors that may negatively affect the present value of proved natural gas and oil reserves. These factors can include volatile natural gas and oil prices, downward revisions in estimated proved natural gas and oil reserve quantities, limited classification of proved reserves associated with successful wells and unsuccessful drilling activities.

A majority of our proved reserves are classified as proved developed non-producing and proved undeveloped and may ultimately prove to be less than estimated.

At December 31, 2004, approximately 77% of our total proved reserves were classified as proved developed non-producing and proved undeveloped. It will take substantial capital to recomplete or drill our non-producing and undeveloped locations. Further, our drilling efforts may be delayed or unsuccessful, and actual reserves may prove to be less than current reserve estimates, which could have a material effect on our financial condition and results of operations.

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Deficiencies of title to our leased interests could significantly affect our financial condition.

Our practice in acquiring exploration leases or undivided interests in natural gas and oil leases is not to incur the expense of retaining lawyers to examine the title to the mineral interest prior to executing the lease. Instead, we rely upon the judgment of lease brokers and others to perform the field work in examining records in the appropriate governmental or county clerk s office before leasing a specific mineral interest. This practice is widely followed in the industry. Prior to the drilling of an exploration well, the operator of the well will typically obtain a preliminary title review of the drillsite lease and/or spacing unit within which the proposed well is to be drilled to identify any obvious deficiencies in title to the well and, if there are deficiencies, to identify measures necessary to cure those defects to the extent reasonably possible. However, such deficiencies may have been cured by the operator of any such wells. It does happen, from time to time, that the examination made by the title lawyers reveals that the lease or leases are invalid, having been purchased in error from a person who is not the rightful owner of the mineral interest desired. In these circumstances, we may not be able to proceed with our exploration and development of the lease site or may incur costs to remedy a defect, which could affect our financial condition.

We may experience shortages of equipment and personnel, 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 and Australia, which we believe may intensify because of current increased industry activity. In addition, the costs and delivery times of rigs, equipment and supplies have risen. Shortages of drilling rigs, equipment, supplies or trained personnel could delay and adversely affect our operations and drilling plans, which could have an adverse effect on our results of operations. While we intend to enter into contracts for the services of drilling rigs in North America and Australia, we may not be successful in doing so.

The demand for, and wage rates of, qualified rig crews have begun to rise in the drilling industry due to the increasing number of active rigs in service. Personnel shortages have occurred in the past during times of increasing demand for drilling services. If the number of active drilling rigs increases, we may experience shortages of qualified personnel to operate our drilling rigs, which could delay our drilling operations and adversely affect our business.

We are subject to complex laws and regulations, including environmental laws and regulations that can adversely affect the cost, manner or feasibility of conducting our business.

Our exploration and production interests and operations are subject to stringent and complex federal, state and local laws and regulations governing the operation and maintenance of our facilities and the handling and discharge of substances into the environment. These existing laws and regulations impose numerous obligations that are applicable to our interests and operations including:

- Air and water discharge permits for drilling and production operations;
- Drilling and abandonment bonds or other financial responsibility assurances;
- Reports concerning operations;

- Spacing of wells;
- Access to properties, particularly in the Powder River Basin;
- Taxation; and
- Other regulatory controls on operating activities.

In addition, regulatory agencies have from time to time imposed price controls and limitations on production by restricting the flow rate of wells below actual production capacity in order to conserve supplies of natural gas and oil.

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Failure to comply with environmental and other laws and regulations applicable to our interests and operations could result in the assessment of administrative, civil, and criminal penalties, the imposition of remedial requirements, and the issuance of orders enjoining or limiting future operations; any of which could have a material adverse affect on our financial condition. Legal requirements are sometimes unclear and are frequently changed in response to economic or political conditions. As a result, it is hard to predict the ultimate cost of compliance with these requirements or their affect on our interests and operations. In addition, existing laws or regulations, as currently interpreted or reinterpreted in the future, or future laws or regulations may have a material adverse affect on our results of operations.

The production, handling, storage, transportation and disposal of natural gas and oil, by-products of natural gas and oil and other substances produced or used in connection with natural gas and oil production operations are regulated by laws and regulations focused on the protection of human health and the environment. Consequently, the discharge or release of natural gas, oil or other substances into the air, soil or water could subject us to liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage, and fines or penalties for related violations of environmental laws or regulations. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may not be able to recover some or any of these costs from insurance.

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 the exploration areas. Approximately 27.5% of our Gippsland Basin property in Victoria may be subject to native title claims. We have been informed by the government of New South Wales that the proportion of land within PEL 238 in the Gunnedah Basin, New South Wales, which is potentially subject to native title claims, cannot be readily determined.

The process of drilling for and producing natural gas and oil involves many operating risks that can cause substantial losses, and we may not have enough insurance to cover these risks adequately.

The natural gas and oil business involves many operating hazards, such as:

- Well blowouts, fires and explosions;
- Surface craterings and casing collapses;
- Uncontrollable flows of natural gas, oil or well fluids;

Pipe and cement failures;

Formations with abnormal pressures;

Stuck drilling and service tools;

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- Pipeline ruptures or spills;
- Natural disasters; and
- Releases of toxic natural gas.

Any of these events could cause substantial losses to us as a result of:

- Injury or death;
- Damage to and destruction of property, natural resources and equipment;
- Pollution and other environmental damage;
- Regulatory investigations and penalties;
- Suspension of operations; and
- Repair and remediation costs.

We could also be responsible for environmental damage caused by previous owners of property that we purchase or lease. As a result, we may incur substantial liabilities to third parties or governmental entities. See Business Governmental Regulation and Business Environmental Regulation . Although we maintain what we believe is appropriate and customary insurance for these risks, the insurance may not be available or sufficient to cover all of these liabilities. If these liabilities are not covered by our insurance, paying them could reduce or eliminate the funds available for exploration, development or acquisitions or result in the loss of our properties.

Approximately 75% of our revenues for the nine months ended September 30, 2005 was from the production of wells located in our Deep Bossier play in East Texas. Any disruption in production or our ability to process and sell our natural gas production from this area would have an adverse effect on our results of operations.

Production of natural gas could unexpectedly be disrupted or curtailed due to reservoir or mechanical problems. Additionally, a majority of our East Texas production is processed through two on-site processing facilities. If these facilities ceased to operate, were destroyed or otherwise needed replacement, it could require 60 to 90 days to replace either one or both of these facilities. A 60 to 90 day curtailment of our east Texas production could reduce current revenues by $4.0 to $6.0 million, with a corresponding reduction in our cash flow.

Our ability to market our natural gas and oil may be impaired by capacity constraints on the gathering systems and pipelines that transport our natural gas and oil.

The availability of a ready market for our natural gas production depends on the proximity of our reserves to and the capacity of natural gas gathering systems, pipelines and trucking or terminal facilities. We enter into agreements with companies that own pipelines used to transport natural gas from the wellhead to contract destination. Those pipelines are limited in size and volume of natural gas flow. Should production begin, other outstanding contracts with other producers and developers could interfere with our access to a natural gas line to deliver natural gas to the market. We do not own or operate any natural gas lines or distribution facilities. Further, interstate transportation and distribution of natural gas is regulated by the federal government through the Federal Energy Regulatory Commission, or FERC. FERC sets rules and carries out administratively the oversight of interstate markets for natural gas and other energy policy. Among FERC s powers is the ability to dictate sale and delivery of natural gas to any markets it oversees.

Additionally, state regulators have vast powers over sale, supply and delivery of natural gas and oil within their state borders. While we do employ certain companies to represent our interests before state regulatory agencies, our interests may not receive favorable rulings from any state agency, or some future occurrence may drastically alter our ability to enter into contracts or deliver natural gas to the market.

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Competition in the natural gas and oil industry is intense, and we are smaller and have a more limited operating history than most of our competitors and increased competitive pressure could adversely affect our results of operations.

We operate in a highly competitive environment. We compete with other natural gas and oil companies in all areas of our operations, including the acquisition of exploratory prospects and proven properties. Our competitors include major integrated natural gas and oil companies, numerous independent natural gas and oil companies, individuals and drilling and income programs. Many of our competitors are large, well-established companies that have substantially larger operating staffs and greater capital resources than we do and that, in many instances, have been engaged in the natural gas and oil business for a much longer time than we have. These companies may be able to pay more for exploratory prospects and productive natural gas and oil properties and may be able to define, evaluate, bid for and purchase more properties and prospects than our financial and human resources permit. In addition, these companies may be able to spend more on the existing and changing technologies that we believe are and will be increasingly important to the current and future success of natural gas and oil companies. Our ability to explore for natural gas and oil prospects and to acquire additional properties in the future will depend on our ability to conduct our operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. Increased competitive pressure could adversely affect our results of operations.

Acquisition prospects are difficult to assess and may pose additional risks to our operations.

Where appropriate, we may evaluate and pursue acquisition opportunities on terms our management considers favorable. In particular, we expect to pursue acquisitions that have the potential to economically increase our natural gas and oil reserves. The successful acquisition of natural gas and oil properties requires an assessment of:

- Recoverable reserves;
- Exploration potential;
- Future natural gas and oil prices;
- Operating costs;
- Potential environmental and other liabilities; and
- Permitting and other environmental authorizations required for our operations.

In connection with such an assessment, we would expect to perform a review of the subject properties that we believe to be generally consistent with industry practices. Nonetheless, the resulting conclusions are inexact and their accuracy inherently uncertain, and such an assessment may not reveal all existing or potential problems, nor will it necessarily permit a buyer to become sufficiently familiar with the properties to fully assess their merits and deficiencies. Inspections may not always be performed on every platform or well, and structural and environmental problems are not necessarily observable even when an inspection is undertaken.

Future acquisitions could pose additional risks to our operations and financial results, including:

- Problems integrating the purchased operations, personnel or technologies;
- Unanticipated costs;
- Diversion of resources and management attention from our exploration business;
- Entry into regions or markets in which we have limited or no prior experience; and
- Potential loss of key employees, particularly those of the acquired organization.

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We cannot control the activities on properties we do not operate, which may affect the timing and success of our future operations.

Other companies operate some of the properties in which we have an interest. As a result, we have a limited ability to exercise influence over operations for these properties or their associated costs. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence operations and associated costs could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities. The success and timing of our drilling and development activities on properties operated by others therefore depend upon a number of factors that are outside of our control, including:

- Timing and amount of capital expenditures;
- The operator s expertise and financial resources;
- Approval of other participants in drilling wells; and
- Selection of technology.

Technological changes could affect our operations.

The natural gas and oil industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement such new technologies at substantial costs. In addition, other natural gas and oil companies have greater financial, technical and personnel resources that may allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We may be unable to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. One or more of the technologies that we currently use or may implement in the future may become obsolete.

Rapid growth could result in a strain on our resources.

Because of our size, our growth, if achieved, will likely place a significant strain on our financial, technical, operational and management resources. The failure to continue to upgrade our technical, administrative, operating and financial control systems or the occurrence of unexpected expansion difficulties, including the recruitment and retention of experienced managers, geoscientists and engineers, could have a material adverse effect on our business, financial condition and results of operations and our ability to timely execute our business plan.

Our ability to successfully execute our business plan is dependent on our ability to obtain adequate financing.

Our business plan, which includes participation in 3-D seismic shoots, the drilling of exploration prospects and development projects and producing property acquisitions, has required and will continue to require substantial capital expenditures. We may require additional financing to fund our planned growth. Our ability to raise additional capital will depend on the results of our operations and the status of various capital and industry markets at the time we seek such capital. Accordingly, we cannot be certain that additional financing will be available to us on acceptable terms, if at all. In particular, the terms of our senior secured notes limit our ability to incur additional indebtedness. In the event additional capital resources are unavailable, we may be required to curtail our exploration and development activities or be forced to sell some of our assets in an untimely fashion or on less than favorable terms.

Not hedging our production may result in losses.

We currently do not hedge our natural gas and oil production. By not hedging our production, we may be more adversely affected by declines in natural gas and oil prices than our competitors who engage in hedging arrangements. Further, should we elect to hedge in the future, such hedges may result in us receiving lower than current prevailing market prices and place additional financial strains on us due to having to post margin calls on our hedges.

Exchange rate fluctuations subject us to unique risks.

As our Australian activities increase, we will be increasingly exposed to the impact of fluctuations in the exchange rate between the Australian dollar and the U.S. dollar. We have only minimal exposure to Canadian currency fluctuations, as almost all of our current revenues and expenses are in U.S. dollars.

We depend on our key personnel, the loss of which could adversely affect our operations and financial performance.

We depend to a large extent on the services of a limited number of senior management personnel and directors. Particularly, the loss of the services of our chief executive officer and chief financial officer could negatively impact our future operations. We have employment contracts with these key members of our senior management team; although, we do not maintain key-man life insurance on any of our senior management. We believe that our success is also dependent on our ability to continue to retain the services of skilled technical personnel. Our inability to retain skilled technical personnel could have a material adverse effect on our business.

Our major shareholders may influence the activities and operations of certain jointly owned properties, which also could result in conflicts of interest.

As of November 4, 2005, Chesapeake and Geostar owned approximately 16.6% and 10.9% of our outstanding common shares, respectively. As a result, Chesapeake and Geostar are in a position to heavily influence the outcome of matters requiring a shareholder vote, including the election of directors, the adoption or amendment of provisions in our Articles of Incorporation and Bylaws and the approval of mergers and other significant corporate transactions. Their high level of ownership may also delay, defer or prevent a change in control of us and may adversely affect the voting and other rights of other shareholders.

The chairman of our board of directors is also a director and chief executive officer of Geostar. Chesapeake has the right to have present an observer at our board of directors meetings. In accordance with the laws of Alberta, our directors are required to act honestly and in good faith with a view to our best interests. The Geostar director on our board of directors also has fiduciary duties to manage Geostar, including its investments in companies such as us, in a manner beneficial to Geostar and its shareholders. In some circumstances, these duties may conflict with his duties as a director of Gastar. Addressing matters, such as board of director conflicts, are subject to the procedures and remedies as provided under the Business Corporations Act (Alberta). See Description of Capital Stock Board of Directors; Election and Removal of Directors .

Each of Chesapeake and Geostar and their subsidiaries are also engaged in the natural gas and oil business. Although we have entered into the Participating and Operating Agreement, or POA, with Geostar dated 2001, and a joint operating agreement with Chesapeake, it is possible that we may in some circumstances be in direct or indirect competition with Chesapeake or Geostar, including competition with respect to certain business strategies and transactions that we may propose to undertake. These conflicts of interest may materially adversely affect our results of operations.

Some of our directors may not be subject to suit in the United States.

Three of our directors reside in Canada. As a result, it may be difficult or impossible to effect service of process within the United States upon those directors, to bring suit against them in the United States or to enforce in the United States courts any judgment obtained there against them predicated upon any civil liability provisions of the United States federal securities laws. Investors should not assume that Canadian courts (a) will enforce judgments of United States courts obtained in actions against those directors predicated upon the civil liability provisions of the United States federal securities laws or the securities or blue sky laws of any state within the United States; or (b) will enforce, in original actions, liabilities against those directors upon the United States federal securities laws or any such state securities or blue sky laws.

Risks Related to this Offering and our Common Stock

There is a limited public market for our common shares.

Although our common shares have been listed on The Toronto Stock Exchange since January 2002, they are thinly traded. As a result, a trade involving a large number of common shares could have an exaggerated effect on the reported market price of 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. Our common shares have also been approved for listing on the American Stock Exchange and are expected to trade on that exchange shortly after the date of this prospectus under the symbol GST .

Our common share price has been and is likely to continue to be highly volatile.

The trading price of our common shares are subject to wide fluctuations in response to a variety of factors, including quarterly variations in operating results, announcements of drilling and rig activity, economic conditions in the natural gas and oil industry, general economic conditions or other events or factors that our beyond our control. See Price Range of Common Shares .

In addition, the stock market in general and the market for natural gas and oil exploration companies in particular have experienced extreme price and volume fluctuations that have often been unrelated or disproportionate to the operating results or asset values of those 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. In the past, following periods of volatility in the overall market and in the market price of a company s securities, securities class action litigation has been instituted against these companies. If this type of litigation were instituted against us following a period of volatility in our common shares trading price, it could result in substantial costs and a diversion of our management s attention and resources, which could have a materially adverse impact on our operations.

Future issuances of our common shares may adversely affect the price of our common shares.

The future issuance of a substantial number of common shares into the public market, or the perception that such issuance could occur, could adversely affect the prevailing market price of our common shares. A decline in the price of our common shares could make it more difficult to raise funds through future offerings of our common shares or securities convertible into common shares. Following the effectiveness of the registration statement to which this prospectus is a part, we believe that substantially all of our outstanding common shares, our common shares that are issued in the future upon the exercise of outstanding options and the common shares issued upon conversion and exercise of the convertible debentures and warrants or additional common shares required to be issued under subscription receipts will be tradable under the U.S. federal securities laws.

Our ability to issue an unlimited number of our common shares under our articles of incorporation may result in dilution or make it more difficult to effect a change in control of the company, which could adversely affect the price of our common shares.

Unlike most corporations formed in the United States, our articles of incorporation chartered under the laws of the Province of Alberta, Canada permit the board of directors to issue an unlimited number of new common shares without shareholder approval, subject only to the rules of the Toronto Stock Exchange or any future exchange on which our stock trades. The issuance of a large number of shares could be effected by our directors to thwart a takeover attempt or offer for us by a third party, even if doing so would benefit our shareholders, which could result in the shares being valued less in the market. The issuance, or the threat of issuance, of large number of shares, at prices that are dilutive to the outstanding shares could also result in the shares being valued less in the market.

Issuance of the common shares upon exercise of warrants and conversion of convertible debentures, together with additional issuances of common shares to purchasers of our senior secured notes for no additional consideration, will dilute the ownership interest of existing shareholders and could adversely affect the market price of our common shares.

We are obligated to issue a substantial number of common shares upon exercise of outstanding common share purchase warrants and upon conversion of our convertible debentures. Additionally, in connection with the issuance of senior secured notes in June and September 2005, we also issued subscription receipts entitling the holders to receive on each of the six, twelve and eighteen-month anniversaries of each of the closings additional common shares equal in value to CDN$4.5 million and CDN$714,286, respectively, based upon then current market prices. These issuances will dilute the ownership interest of existing shareholders. Any sales in the public market of the common shares issuable upon such exercise of warrants, conversion, or issuance of additional common shares could adversely affect prevailing market prices of our common shares. In addition, the existence of these warrants and convertible debentures may encourage short selling by market participants.

If we are unable to meet the Securities and Exchange Commission s requirements related to the assessment, attestation and effectiveness of our internal controls, we may suffer a loss of investor confidence and the price of our common shares may be adversely affected.

Under the Exchange Act, we will be required to include in our annual report a report on internal controls. This report must state management s responsibility for establishing and maintaining an adequate internal control structure and procedures for financial reporting. The report must also contain an assessment as of the end of the year of the effectiveness of those internal controls. The Exchange Act also requires our registered public accounting firm to test and report on the assessment made by management. Assuming effectiveness of this prospectus during the year 2005, these new rules could become effective for us as early as for the year ending December 31, 2006, depending upon our market capitalization at June 30, 2006. In order to meet these requirements, we must document and test the effectiveness of our internal controls and then allow time for our registered public accounting firm to audit our internal control structure. The amount of work required by us to prepare, maintain and test our internal control structure could be extensive. In the event that management is unable to complete its assessment of the effectiveness of our internal controls over financial reporting or our auditors are unable to attest to management s assessment or do their own assessment, or if these internal controls are not effective, we might experience an adverse reaction in the financial marketplace due to a loss of investor confidence in the reliability of our financial statements, which could negatively impact the market price of our common shares.

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CAUTIONARY STATEMENTS REGARDING FORWARD-LOOKING STATEMENTS

Some of the information included in this prospectus contains forward-looking statements . These statements can be identified by the use of forward-looking words, including may , expect , anticipate , plan , project , believe , estimate , intend , will , should or other similar Forward-looking statements may include statements that relate to, among other things:

- Our financial position;
- Business strategy and budgets;
- Anticipated capital expenditures;
- Drilling of wells;
- Natural gas and oil reserves;
- Timing and amount of future production of natural gas and oil;
- Operating costs and other expenses;
- Cash flow and anticipated liquidity;
- Prospect development; and
- Property acquisitions and sales.

Although we believe the expectations reflected in such forward-looking statements are reasonable, we cannot assure you that such expectations will occur. These forward-looking statements involve known and unknown risks, uncertainties and other factors that may cause our actual results, performance or achievements to be materially different from actual future results expressed or implied by the forward-looking statements. These factors include among others:

- Low and/or declining prices for natural gas and oil;
- Natural gas and oil price volatility;

The risks associated with exploration, including cost overruns and the drilling of non-economic wells or dry holes;

Ability to raise capital to fund capital expenditures;

The ability to find, acquire, market, develop and produce new natural gas and oil properties;

Uncertainties in the estimation of proved reserves and in the projection of future rates of production and timing of development expenditures;

Operating hazards attendant to the natural gas and oil business;

Downhole drilling and completion risks that are generally not recoverable from third parties or insurance;

Potential mechanical failure or under-performance of significant wells or pipeline mishaps;

Weather conditions;

Availability and cost of material and equipment;

Delays in anticipated start-up dates;

Actions or inactions of third-party operators of our properties;

Ability to find and retain skilled personnel;

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Strength and financial resources of competitors;

Federal and state regulatory developments and approvals;

Environmental risks;

Worldwide economic conditions; and

Operational and financial risks associated with foreign exploration and production.

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 of the proceeds from the sale of the common shares by the selling shareholders under this prospectus. All proceeds from the sale of those shares will be for the respective accounts of the selling shareholders.

PRICE RANGE OF COMMON SHARES

Our common shares are listed on The Toronto Stock Exchange under the symbol YGA and have been traded in the United States over-the-counter market under the symbol GSREF.PK . Our common shares have also been approved for listing on the American Stock Exchange and are expected to trade on that exchange shortly after the date of this prospectus under the symbol GST . The following table sets forth the high and low sale prices of our common shares as reported on The Toronto Stock Exchange (CDN$) and as quoted in the United States over-the-counter market for the periods presented. The prices in the table below have been adjusted for stock splits.

	Toronto Stock Exchange		U.S. Over-the-Counter	
	High	**Low**	**High**	**Low**
2005				
Fourth Quarter (through December 30, 2005)	CDN$ 4.62	CDN$ 3.85	$ 4.22	$ 3.22
Third Quarter	CDN$ 4.72	CDN$ 2.75	$ 4.01	$ 2.25
Second Quarter	CDN$ 4.48	CDN$ 3.38	$ 3.85	$ 2.74
First Quarter	CDN$ 4.95	CDN$ 3.64	$ 3.92	$ 3.02

2004				
Fourth Quarter	CDN$ 5.50	CDN$ 3.65	$ 4.24	$ 3.00
Third Quarter	CDN$ 4.50	CDN$ 3.28	$ 3.52	$ 2.11
Second Quarter	CDN$ 4.35	CDN$ 3.40	$ 3.17	$ 2.61
First Quarter	CDN$ 4.50	CDN$ 2.40	$ 3.19	$ 1.87
2003				
Fourth Quarter	CDN$ 2.65	CDN$ 2.30	$ 1.98	$ 1.70
Third Quarter	CDN$ 2.53	CDN$ 2.00	$ 1.87	$ 1.41
Second Quarter	CDN$ 2.24	CDN$ 1.98	$ 1.58	$ 1.39
First Quarter	CDN$ 2.32	CDN$ 1.95	$ 1.55	$ 1.36

As of December 9, 2005, there were 629 holders of record of our common shares. The last reported sale prices of our common shares on The Toronto Stock Exchange and as quoted in the United States over-the-counter market on December 30, 2005 were CDN$4.25 and $3.63, respectively.

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As of September 30, 2005, 17,425,850 common shares were subject to outstanding stock options granted under our 2002 Stock Option Plan, 12,814,600 shares of which are vested but have not been exercised, and 2,992,261 common shares were subject to outstanding warrants, all of which shares were exercisable as of such date. As of September 30, 2005, we had outstanding $30.0 million in principal amount of convertible debentures. The convertible debentures are convertible at the option of the holders into an aggregate of 6,849,315 common shares.

As of September 30, 2005, 65,719,307 common shares were eligible for resale pursuant to Rule 144 under the Securities Act, excluding the shares covered by this prospectus. Pursuant to the indenture governing the convertible debentures and the terms of the certain warrants, we have agreed to register for resale the 6,849,315 common shares issuable upon the conversion of our convertible debentures and the 2,759,740 common shares issuable upon exercise of the placement agent warrants, all of which shares are covered by this prospectus. Pursuant to the terms of our senior secured notes, we have agreed to register for resale the 1,423,623 common shares issued or issuable in connection with the sale of our senior secured notes, all of which are covered by this prospectus, plus up to an estimated 5,029,858 additional common shares to be issued pursuant to subscription rights at various dates pursuant to the terms of the original sales of the registrant s senior secured notes.

DIVIDEND HISTORY

We have never declared or paid any cash dividends on our common shares. We anticipate that we will retain any future earnings, if any, to satisfy our operational and other cash needs and do not anticipate paying any cash dividends on our common shares in the foreseeable future. In addition, our current senior secured notes prohibit us from paying cash dividends as long as such debt remains outstanding.

Pursuant to the provisions of the *Business Corporations Act* (Alberta), we are prohibited from declaring or paying a dividend if there are reasonable grounds for believing that (1) we are, or would after the payment be, unable to pay our liabilities as they become due or (2) the realizable value of our assets would thereby be less than the aggregate of our liabilities and stated capital of all classes.

For a discussion of Canadian laws, decrees and regulations that restrict the import or export of capital, affect the remittance of dividends or other payments to non-resident holders of our common shares, or relate to taxes, including withholding provisions, to which U.S. holders of our common shares are subject, as well as pertinent provisions of the tax treaty between Canada and the United States, please see Material Income Tax Consequences .

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SELECTED HISTORICAL FINANCIAL AND OPERATIONAL INFORMATION

The following table presents selected historical financial and operational information as of and for the periods indicated. The selected consolidated financial data as of and for the years ended December 31, 2004, 2003, 2002, 2001 and 2000 are derived from our audited consolidated financial statements. The selected consolidated financial data as of September 30 , 2005 and for the nine months ended September 30, 2005 and 2004 are derived from our unaudited consolidated financial statements. On May 16, 2000, we changed our name to Gastar Exploration Ltd. and began our natural gas and oil operations. Prior to May 16, 2000, we engaged in limited minerals exploration activities under the name CopperQuest Inc.

Our unaudited consolidated financial statements include, in the opinion of management, all adjustments, consisting only of normal, recurring adjustments, that management considers necessary for a fair statement of the results of those periods. Our historical results are not necessarily indicative of results to be expected in any future period and the results for the nine months ended September 30, 2005 should not be considered indicative of results expected for the full 2005 fiscal year.

You should read the following selected consolidated financial and operational information in conjunction with our audited and unaudited consolidated financial statements and the accompanying notes included elsewhere in this prospectus and the section of this prospectus entitled, Management s Discussion and Analysis of Financial Condition and Results of Operations .

	As of and for the Nine Months Ended September 30,		As of and for the Years Ended December 31,				
	2005	2004	2004	2003	2002	2001	2000
	(Unaudited)		(in thousands, except per share amounts)				
Consolidated Statement of Loss Data:							
Revenues	$ 17,496	$ 1,688	$ 6,059	$ 1,461	$ 783	$ 228	$
Lease operating, transportation and selling	$ 4,024	$ 937	$ 2,000	$ 712	$ 769	$ 138	$
Depletion, depreciation and amortization	$ 9,063	$ 750	$ 3,233	$ 572	$ 360	$ 67	$
Impairment of natural gas and oil properties	$ 8,697	$	$ 6,306	$ 552	$ 377	$ 3,960	$ 127
General and administrative expense	$ 5,997	$ 1,916	$ 4,023	$ 1,909	$ 1,933	$ 1,008	$ 198
Operating loss before interest expense	$ (10,426)	$ (1,984)	$ (9,587)	$ (2,368)	$ (2,657)	$ (4,960)	$ (382)
Net loss	$ (20,921)	$ (3,391)	$ (12,776)	$ (4,947)	$ (4,599)	$ (4,793)	$ (382)
Basic and diluted loss per share	$ (0.17)	$ (0.03)	$ (0.12)	$ (0.05)	$ (0.05)	$ (0.05)	$ (0.0)
Shares used in the calculation of basic and diluted loss per share	121,205	110,709	111,374	104,958	98,618	94,648	80,435
Consolidated Balance Sheet Data:							
Net natural gas and oil properties	$ 158,391		$ 56,556	$ 35,791	$ 34,457	$ 23,069	$ 8,411
Total assets	$ 178,317		$ 84,442	$ 38,757	$ 36,034	$ 24,458	$ 18,484
Long term liabilities	$ 108,861		$ 60,668	$ 10,554	$ 12,291	$ 1,877	$
Total shareholders equity	$ 47,877		$ 21,976	$ 23,669	$ 22,430	$ 17,656	$ 18,180
Production Data (1):							
Production:							
Natural gas (MMcf)	2,614.8	353.0	1,108.0	385.0	393.2	81.7	
Oil (MBbl)	1.6	1.1	1.8	1.0	3.1	2.8	

Oil Natural gas equivalents (Mmcfe)	2,624.3	359.4	1,118.8	391.0	411.6	98.5	
Natural gas (MMcfd)	9.6	1.3	3.0	1.1	1.1	0.2	
Oil (MBod)	0.0	0.0	0.0	0.0	0.0	0.0	
Oil Natural gas equivalents (Mmcfed)	9.6	1.3	3.1	1.1	1.1	0.3	
Average Sales Prices:							
Natural gas (per Mcf)	$ 6.67	$ 4.67	$ 5.40	$ 3.72	$ 1.33	$ 1.83	$
Oil (per Bbl)	$ 50.19	$ 37.75	$ 40.08	$ 27.89	$ 20.15	$ 20.55	$

(1) There was no reportable production of natural gas and oil prior to 2001.

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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 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. In light of these risks, uncertainties and assumptions, the forward looking events discussed may not occur.

Gastar Exploration Ltd.

Overview

We are an independent energy company engaged in the exploration, development and production of natural gas and oil in the United States and Australia. Our principal business activities include the identification, acquisition, and subsequent exploration and development of natural gas and oil properties. Our emphasis is on prospective deep structures identified through seismic and other analytical techniques as well as unconventional natural gas reserves, such as coal bed methane. We currently are pursuing conventional natural gas exploration in the Deep Bossier play in the Hilltop area in East Texas and the Appalachian Basin in West Virginia. In our coal bed methane, or CBM, projects, we use industry technologies to assist us in developing commercial natural gas production from known coal beds. Our primary CBM properties are in the United States in the Powder River Basin and in the Gunnedah and Gippsland Basins of Australia.

Recent Operational Events. Management believes that the following recent operational events are important to the success of our business plan:

The Fridkin-Kaufman #1, or F-K #1, well is a Deep Bossier sand well located in the Hilltop area of East Texas, commenced production in late September 2004, with initial production rates of approximately 15.0 MMcfd (8.5 MMcfd net). As a result of the Geostar acquisition, our working interest in this well increased from 75% to 98%. Current daily production is approximately 4.1 MMcfd (3.1 MMcfd net).

The Cheney #1 well completed drilling in the Hilltop area to test the Deep Bossier sand encountered in the F-K #1 well. This well is approximately one mile north of the F-K #1 well. The Cheney #1 well encountered approximately 400 net feet of potential pay zones based on natural gas shows while drilling and on logs. As a result of the Geostar acquisition, our working interest in this well increased from 75% to 98%. The well commenced production in mid-February 2005 at an initial rate of approximately 7.0 MMcfd (4.0 MMcfd net). Current daily production is approximately 0.9 MMcfd (0.7 MMcfd net) after re-stimulation in August 2005.

We completed drilling the Lone Oak Ranch #1 well in the Hilltop area and began production operations in early May 2005 at an initial rate of approximately 7.0 MMcfd (3.8 MMcfd net). As a result of the Geostar acquisition, our working interest in this well increased from 73% to 98%. Current daily production is approximately 2.1 MMcfd (1.6 MMcfd net).

We began drilling the Greer #1 well, our fourth Bossier sand well in the Hilltop area in January 2005. The Greer #1 well is located approximately one mile from the F-K #1well. We drilled the Greer #1 well to a total depth of 17,800 feet. Based on natural gas shows during drilling and electric logs, the well encountered approximately 57 net feet of apparent pay with high indicative porosity similar to the

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producing zones in our previous wells. As a result of the Geostar acquisition, our working interest in this well increased from 73% to 98%. The well commenced production in July 2005 at an initial rate of approximately 5.0 MMcfd (3.9 MMcfd net). Current daily production is approximately 1.9 MMcfd (1.5 MMcfd net).

Drilling commenced in February 2005 on the Fridkin-Kaufman #2, or F-K #2, well to a total depth of 18,700 feet. Based on electric logs, the well encountered approximately 74 net feet of apparent pay in the Bossier lower K sand below 18,000 feet. The well also encountered over 120 feet of indicated pay in the shallower Travis Peak formation. The well is located approximately 2,200 feet from the F-K #1 well. The completion attempt in the Bossier sands was not successful. A completion attempt in the Travis Peak was made in October 2005, and current production results are being evaluated. As a result of the Geostar acquisition, our working interest increased from 78% to 100%.

We commenced drilling the Donelson #1 well in May 2005. This sixth Deep Bossier well in the Hilltop area of East Texas was drilled to a total depth of 19,200 feet. The well has encountered an apparent commercial gas discovery in the Pettet formation at approximately 10,000 feet. In addition, the Donelson #1 well has encountered a productive interval within the Knowles limestone. A dedicated Knowles well will be drilled on the Donelson #1 location in order to accelerate the development and production of the Knowles formation and to take advantage of current high natural gas prices. The Donelson #1 well also encountered apparently productive sands in the upper and middle Bossier formations along with a series of apparently productive pay zones in the lower or deep Bossier formation from approximately 17,000 feet to 19,000 feet. The lower Bossier sands appear to correlate to a similar series of sands discovered by us in the earlier Belin Trust A-1 well. We will undertake a completion in the lower Bossier pays immediately after the dedicated Knowles well is drilled. The Donelson Knowles well was spudded in early November 2005 and will require approximately 45 days to drill and complete. As a result of the Geostar acquisition our working interest in this well increased from 78% to 100%.

We have contracted with a third party to provide us with two 20.0 MMcfd on-site processing facilities for our East Texas properties. For a monthly rental fee of approximately $35,000 per facility, the third party constructs and operates the natural gas processing plants. To date, our natural gas processing plants have operated with mechanical downtime of less than 12 hours per month. Current natural gas processing plant capacity is not anticipated to be reached until later in 2006. Prior to reaching current plant capacity, we anticipate contracting with a third party to construct and operate additional needed plants for a similar monthly fee. Lead time to construct a new natural gas processing plant is approximately 60 to 90 days.

Our CBM joint venture partners drilled and completed three vertical CBM wells and one horizontal CBM well during the third and fourth quarters of 2004 on our 2.0 million gross acre PEL 238 project in New South Wales, Australia. The vertical wells were fracture stimulated with large volumes of sand proppant. These wells commenced dewatering operations in the fourth quarter of 2004. The wells have demonstrated high water rates indicative of high permeability within the coal formation and have begun producing gas after 60 to 90 days of de-watering with several of the wells producing natural gas from first production. We believe that the performance of these wells to date is confirmation of the presence of a significant CBM deposit that can be developed on a commercial basis. Further evaluation activities are anticipated for the third and fourth quarters of 2005 and in the first quarter of 2006. During the first and second quarters of 2005, we drilled the first two dedicated CBM test wells on our EL 4416 license in the Gippsland Basin, located in Victoria, Australia. We hold a 75% working interest in the CBM and Mineral Sands rights on the 1.4 million gross acre concession with the balance owned and operated by a subsidiary of Geostar. The wells are anticipated to be completed during the third quarter utilizing open-hole completion techniques commonly used in the Powder River Basin area.

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On November 4, 2005, we closed a transaction with Chesapeake Energy Corporation whereby Chesapeake:

- Acquired approximately 27.2 million newly issued common shares from us equal to 19.9% of its then outstanding common shares for $76.0 million (CDN$89.9 million) in cash or CDN$3.31 per share, before fees and expenses;
- Acquired a 33.33% working interest in our Deep Bossier play in the Hilltop prospect area of Leon and Robertson Counties of East Texas; and
- Formed an area of mutual interest to explore jointly in 13 counties in East Texas.

Chesapeake agreed to pay approximately $7.8 million, before fees and expenses, to acquire the shares described above and to pay a disproportionate amount off future drilling costs described below, in exchange for an undivided 33.33% of our leasehold working interests in the Deep Bossier Hilltop prospect, less and except 160 acres surrounding each of our existing well bores. Chesapeake agreed to pay 44.44% of the drilling costs through casing point in the first six wells drilled by the parties in the Hilltop prospect to a depth sufficient to test the Deep Bossier formation (an approximate depth of 19,000 feet) in order to earn its 33.33% leasehold working interest. Chesapeake may provide one to two additional drilling rigs in 2006 to accelerate Hilltop development, if necessary. The transaction also provided for the formation of an AMI, covering all of Leon, Robertson, Houston, Cherokee, Madison, Anderson, Angelina, Nacogdoches, Trinity, Polk, Shelby, San Augustine and Sabine Counties in East Texas (the AMI Area). For a period of three years from November 4, 2005, we will offer Chesapeake the exclusive first right to purchase up to an undivided 50% of any leasehold/working interest rights acquired by us in the AMI Area on pre-determined terms. The AMI is one-way Chesapeake will not be obligated to present us any interests it now owns or acquires in the future in the AMI Area.

Results of Operations

The following is a comparative discussion of the results of operations for the nine months ended September 30, 2005 and 2004 and for the years ended December 31, 2004, 2003 and 2002. It should be read in conjunction with the financial statements and the related notes and other information included elsewhere in this prospectus.

Nine Months Ended September 30, 2005 compared to the Nine Months Ended September 30, 2004

Revenues. Substantially all of our revenues are derived from the production of natural gas in the United States. We reported revenues of $17.5 million for the nine months ended September 30, 2005, up from $1.7 million for the comparable period in 2004. This increase was attributable to the commencement of East Texas production of natural gas from the F-K #1 well in the third quarter of 2004, from the Cheney #1 well in the first quarter of 2005, from the Lone Oak Ranch #1 well in the second quarter of 2005, the Greer well in July 2005 and additional production from new CBM wells drilled in the Powder River Basin. The acquisition of additional leasehold and working interests in East Texas and the Powder River Basin from Geostar and higher prices for both natural gas and oil also contributed to the increase. Of the increase in revenues, 67% was attributed to higher production rates and 33% resulted from price increases.

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Natural gas and oil production and average sales prices. The table below sets forth production and sales information for the periods indicated.

	Nine Months Ended September 30,	
	2005	**2004**
Production:		
Natural gas (MMcf)	2,614.8	353.0
Oil (MBbls)	1.6	1.1
Total (MMcfe)	2,624.3	359.4
Natural gas (MMcfd)	9.6	1.3
Oil (MBod)	0.0	0.0
Total (MMcfed)	9.6	1.3
Average sales price:		
Natural gas (per Mcf)	$ 6.67	$ 4.67
Oil (per Bbl)	$ 50.19	$ 37.75
Lease operating, transportation and selling (per Mcfe)	$ 1.53	$ 2.61

Depletion, depreciation and amortization. We reported depletion, depreciation and amortization (DD&A) of $9.1 million for the nine months ended September 30, 2005, up from $750,000 for the nine months ended September 30, 2004. This increase was attributable to the commencement of production of natural gas from the wells in East Texas and the acquisition of additional leasehold and working interest properties in East Texas and the Powder River Basin from Geostar. Of the increase in DD&A expense, 57% was attributed to higher production rates and 43% was due to an increase in DD&A rate per unit. The DD&A rate for the period ended September 30, 2005 was $3.45 per Mcfe, as compared to prior comparable period of $2.09 per Mcfe. The increase in the DD&A rate is primarily due to higher capital expenditures in East Texas.

Impairment of natural gas and oil properties. We reported an impairment of natural gas and oil properties of $8.7 million for the nine months ended September 30, 2005 as compared to no impairment for the period ended September 30, 2004. The impairment is the result of net natural gas and oil property costs, as adjusted for related deferred income taxes and other adjustments, exceeding the sum of estimated future net revenues using prices in effect at June 30, 2005 held constant of $5.32 per Mcf for natural gas and $52.33 per barrel for oil, discounted at 10%, and unproven properties of $93.3 million at the date of impairment, as adjusted for related income taxes and other adjustments. The impairment was primarily the result of limited reserve additions during the current interim period and higher costs incurred to drill and complete the East Texas wells. At September 30, 2005, using prices in effect of $14.27 per Mcf of natural gas and $62.25 per barrel of oil and unproven property costs of $71.6 million, we had a ceiling limitation cushion of approximately $39.3 million.

Interest and debt related items. We reported interest and debt related items of $10.7 million for the nine months ended September 30, 2005, up from $1.5 million for the nine months ended September 30, 2004. This increase was due to higher debt outstanding as a result of the sale in 2004 of $3.25 million of subordinated unsecured notes payable, the sale in 2004 of $30.0 million of convertible senior debentures, the private placement in 2005 of $73.0 million of senior secured notes and the issuance in June 2005 of $32.0 million in unsecured subordinated notes to Geostar. In addition in June 2005, the $26.5 million senior unsecured notes were paid in full and the unamortized deferred charges relating to these notes were fully amortized resulting in an additional $2.3 million of interest expense.

Lease operating, transportation and selling. We reported lease operating, transportation and selling expenses of $4.0 million for the nine months ended September 30, 2005, up from $937,000 for the nine months ended September 30, 2004. This increase was due to higher production volumes and an increased number of

producing wells which was partially offset by a reduction in severance and property taxes. Our lease operating transportation and selling expense per Mcfe decreased to $1.53 during the nine months ended September 30, 2005 from $2.61 for the comparable period in 2004.

General and administrative. We reported general and administrative expenses of $6.0 million for the nine months ended September 30, 2005, up from $1.9 million for the nine months ended September 30, 2004. This increase in general and administrative expenses was primarily due to higher contract staff and professional service charges and compensation expense due to the issuance of stock options.

Year Ended December 31, 2004 compared to Year Ended December 31, 2003.

Revenues. Substantially all of our revenues are derived from the production of natural gas in the United States. We reported revenues of $6.1 million for the year ended December 31, 2004, up from $1.5 million for the year ended December 31, 2003. This increase was attributable to the commencement of production of natural gas from the F-K #1 well in East Texas in the third quarter of 2004, additional production from new CBM wells drilled in the Powder River Basin, and higher commodity prices for both natural gas and oil. Of the increase in revenues, 59% was attributed to higher production rates and 41% resulted from price increases.

Natural Gas and Oil Production and Average Sales Prices. Natural gas represents substantially all of our production. The table below sets forth production and sales information for the periods indicated.

	Years Ended December 31,	
	2004	**2003**
Production:		
Natural gas (MMcf)	1,108.0	385.0
Oil (MBbls)	1.8	1.0
Total (MMcfe)	1,118.8	391.0
Natural gas (MMcfd)	3.0	1.1
Oil (MBod)	0.0	0.0
Total (MMcfed)	3.1	1.1
Average sales prices:		
Natural gas (per Mcf)	$ 5.40	$ 3.72
Oil (per Bbl)	$ 40.08	$ 27.89
Lease operating, transportation and selling (per Mcfe)	$ 1.78	$ 1.82

Depletion, depreciation and amortization. We reported depletion, depreciation and amortization of $3.2 million for the year ended December 31, 2004, up from $572,000 for the year ended December 31, 2003. This increase was attributable to the commencement of production of natural gas from the F-K #1 well in East Texas in the third quarter of 2004 and additional production from new CBM wells drilled in the Powder River Basin. Of the increase in DD&A expense, 40% was attributed to higher production rates and 60% was due to an increase in DD&A rate per unit. The DD&A rate for the period ended December 31, 2004 was $2.89 per Mcfe, as compared to $1.46 for the comparable period in 2003.

Impairment of natural gas and oil properties. We recorded an impairment of natural gas and oil properties of $6.3 million for the year ended December 31, 2004, up from $552,000 for the comparable period ended 2003. The current year impairment is the result of net natural gas and oil property costs, as adjusted for related deferred income taxes and other adjustments, exceeding the sum of estimated future net revenues using prices in effect at the end of the period held constant of $4.98 per Mcf for natural gas and $27.36 per barrel for oil, discounted at 10%, and unproven property at historic cost of $29.8 million, which was lower than the estimated fair market value, as adjusted for related income taxes and other adjustments. The 2004 impairment was primarily due to the result of high initial drilling and completion costs on our Deep Bossier wells in East Texas coupled with limited production history that limited the current recording of proven reserves.

Interest and debt related items. We reported interest and debt related items of $3.2 million for the year ended December 31, 2004, up from $2.6 million for the year ended December 31, 2003. This increase was due to higher debt outstanding as a result of the issuance of $15.0 million and $10.0 million senior unsecured notes, $3.25 million of subordinated unsecured notes and $30.0 million of convertible debentures in 2004.

Lease operating, transportation and selling. We reported lease operating, transportation and selling expenses of $2.0 million for the year ended December 31, 2004, up from $712,000 for the year ended December 31, 2003. This increase was due to higher production volumes and an increased number of producing wells. Our lease operating expense per Mcfe decreased to $1.78 during the year-ended December 31, 2004 from $1.82 for the comparable period in 2003.

General and administrative. We reported general and administrative expenses of $4.0 million for the year ended December 31, 2004, up from $1.9 million for the year ended December 31, 2003. This increase in general and administrative expenses was primarily due to higher contract staff and professional service charges and the recording of compensation expense due to the issuance of stock options in April and August 2004.

Year Ended December 31, 2003 compared to Year Ended December 31, 2002.

Revenues. Substantially all of our revenues are derived from the production of natural gas in the United States. We reported revenues of $1.5 million for the year ended December 31, 2003, up from $783,000 for the year ended December 31, 2002. This increase was attributable to additional production from new CBM wells drilled in the Powder River Basin and higher commodity prices for both natural gas and oil. The increase in revenues was almost entirely attributable to price increases during the comparable periods.

Natural Gas and Oil Production and Average Sales Prices. Natural gas represents substantially all of our production. The table below sets forth production and sales information for the periods indicated.

	Years Ended December 31,	
	2003	**2002**
Production:		
Natural gas (MMcf)	385.0	393.2
Oil (MBbls)	1.0	3.1
Total (MMcfe)	391.0	411.6
Natural gas (MMcfd)	1.1	1.1
Oil (MBod)	0.0	0.0
Total (MMcfed)	1.1	1.1

Average sales prices:		
Natural gas (per Mcf)	$ 3.72	$ 1.33
Oil (per Bbl)	$ 27.89	$ 20.15
Lease operating, transportation and selling (per Mcfe)	$ 1.82	$ 1.75

Depletion, depreciation and amortization. We reported depletion, depreciation and amortization of $572,000 for the year ended December 31, 2003, up from $360,000 for the year ended December 31, 2002. This increase was attributable to additional production from new CBM wells drilled in the Powder River Basin. The increase in DD&A was almost entirely attributable to increases in the DD&A rate. The DD&A rate for the period ended December 31, 2003 was $1.46 per Mcfe, as compared to $0.87 for the comparable period in 2002.

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Impairment of natural gas and oil properties. We recorded an impairment of natural gas and oil properties of $552,000 for the year ended December 31, 2003, up from $377,000 for the comparable period ended 2004. The current year impairment is the result of net natural gas and oil property costs, as adjusted for related deferred income taxes and other adjustments, exceeding the sum of estimated future net revenues using prices in effect at the end of the period held constant of $4.67 per Mcf for natural gas and $29.48 per barrel for oil, discounted at 10%, and unproven property at historic cost of $26.9 million, which was lower than the estimated fair market value, as adjusted for related income taxes and other adjustments. Of the 2003 impairment, the majority was due to the entering into of the Powder River Basin earn-in joint venture. The 2002 impairment was all related to our Australian operations.

Interest and debt related items. We reported interest and debt related items of $2.6 million for the year ended December 31, 2003, up from $2.0 million for the year ended December 31, 2002. This increase was attributable to the issuance of $6.7 million of convertible debentures that was completed in 2003.

Lease operating, transportation and selling. We reported lease operating, transportation and selling of $712,000 for the year ended December 31, 2003, down from $769,000 for the year ended December 31, 2002. This 7% decrease was primarily attributable to the sale of certain Powder River Basin assets in the second quarter of 2003. Our lease operating expense per Mcfe increased to $1.82 during the year ended December 31, 2003 from $1.75 for the comparable period in 2002.

General and administrative. We reported general and administrative of $1.9 million for each of the years ended December 31, 2003 and 2002.

Recent Developments

Issuance of Senior Secured Notes and Common Shares. On June 17, 2005, we completed the private placement of $63.0 million in principal amount of senior secured notes and 1,217,269 common shares. The notes bear interest at three month LIBOR plus 6% and mature on June 18, 2010. We also committed to issue to the purchasers of the notes, for no additional consideration, common shares in CDN$4.5 million increments on each of the six, twelve and eighteen-month anniversaries of the original note closing date valued on a five day weighted average trading price immediately prior to the date of issuance.

On September 19, 2005, we issued to the holders of our senior secured notes an additional $10.0 million of senior secured notes on substantially the same terms as the original June 2005 private placement, including the issuance of 206,354 common shares to the note holders. The common shares issued in the transaction represented an aggregate value of CDN$714,286 based upon the five day weighted average trading price of CDN$3.4615 per share for the five trading days immediately prior to closing. In connection with the sale of the additional notes, we have agreed to issue to the purchasers of the notes, for no additional consideration, common shares in CDN$714,286 increments on each of the six, twelve and eighteen-month anniversaries of the closing date, valued on a five day weighted average trading price immediately prior to the date of issuance.

On December 19, 2005, pursuant to the Senior Secured Notes, we issued to the Senior Secured Notes holders, for no additional consideration, an additional 1,082,105 common shares valued at CDN$4.1586, the five day weighted average trading price immediately prior to the date of issuance. Such shares were issued to the purchasers of the Senior Secured Notes on the six month anniversary of the original $63.0 million note issuance pursuant to subscription receipts.

We have the right, exercisable quarterly to June 16, 2007, to require the original purchasers of the senior secured notes to purchase additional notes in an amount limited to an additional $10.0 million in principal. If additional notes are issued, the purchasers will also be entitled to receive, for no additional consideration, additional common shares and subscription receipts on similar terms as those issued with the original notes in a pro rata amount based on the additional principal amount of the notes. To issue these additional notes, we must meet certain requirements as set forth in the senior secured notes. For additional information on the requirement to issue additional notes, see Description of Indebtedness Senior Secured Notes .

Geostar Acquisition. Concurrently with the private placement of senior secured notes, we closed the acquisition of additional leasehold and working interest properties from Geostar in the Hilltop area of East Texas and in the Powder River Basin of Wyoming and Montana. We paid a total of $68.5 million for the interests acquired from Geostar consisting of $30.5 million in cash, 1,650,133 common shares valued at CDN$4.50 per share and $32.0 million in unsecured subordinated notes maturing on January 31, 2006. The acquisition increased our working interest position in the Hilltop area to an average of over 90% and gave us operational control of the properties. The acquisition of additional Powder River Basin interests provides us with a larger interest in properties currently being developed through an existing joint venture.

On August 11, 2005, we executed an agreement with Geostar whereby the Geostar $32.0 million unsecured subordinated note was cancelled. In conjunction with the note cancellation, we agreed to issue Geostar 6,373,694 common shares, calculated by dividing $17.0 million by an assumed value of CDN$3.25 per share and a new unsecured subordinated note for $15.0 million. The new Geostar note bears interest, payable monthly commencing February 15, 2006, at three-month LIBOR plus 4.5% and matures November 15, 2006. The note requires monthly principal payments of $1.5 million commencing February 15, 2006 and continuing for nine months thereafter with a final principal payment of $1.5 million due on November 15, 2006. We may elect to pay interest in kind through the issuance of additional notes with such notes maturing on January 15, 2007. We may also be required to issue additional common shares to Geostar in the future based on the results of certain East Texas drilling, as described in Certain Relationships and Related Party Transactions .

On November 4, 2005, we closed a transaction with Chesapeake Energy Corporation whereby Chesapeake:

- Acquired approximately 27.2 million newly issued common shares from us equal to 19.9% of its then outstanding common shares for $76.0 million (CDN$89.9 million) in cash or CDN$3.31 per share, before fees and expenses;
- Acquired a 33.33% working interest in our Deep Bossier play in the Hilltop prospect area of Leon and Robertson Counties of East Texas; and
- Formed an area of mutual interest to explore jointly in 13 counties in East Texas.

Chesapeake agreed to pay approximately $7.8 million, before fees and expenses, to acquire the shares described above and to pay a disproportionate amount off future drilling costs described below, in exchange for an undivided 33.33% of our leasehold working interests in the Deep Bossier Hilltop prospect, less and except 160 acres surrounding each of our existing well bores. Chesapeake agreed to pay 44.44% of the drilling costs through casing point in the first six wells drilled by the parties in the Hilltop prospect to a depth sufficient to test the Deep Bossier formation (an approximate depth of 19,000 feet) in order to earn its 33.33% leasehold working interest. Chesapeake may provide one to two additional drilling rigs in 2006 to accelerate Hilltop development, if necessary. The transaction also provided for the formation of an AMI, covering all of Leon, Robertson, Houston, Cherokee, Madison, Anderson, Angelina, Nacogdoches, Trinity, Polk, Shelby, San Augustine and Sabine Counties in East Texas (the AMI Area). For a period of three years from November 4, 2005, we will offer Chesapeake the exclusive first right to purchase up to an undivided 50% of any leasehold/working interest rights acquired by us in the AMI Area on pre-determined terms. The AMI is one-way Chesapeake will not be obligated to present us any interests it now owns or acquires in the future in the AMI Area. For additional information on the Chesapeake transaction, see Business-Natural Gas and Oil Operations-Transaction with Chesapeake Energy Corporation .

Common Share Placement. On June 30, 2005, we completed a private placement of 6,617,736 common shares at CDN$3.31 per share. The estimated net proceeds from this placement were $16.4 million (CDN$20.5 million), after deducting placement fees and expenses.

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Business Environment

The price we receive for our natural gas production is influenced by both national gas price trends and regional gas prices. On a national basis, natural gas prices increased in 2004 generally due to increases in crude oil prices, economic growth and general concerns about future natural gas supplies. Since most of our production for the first three quarters of 2004 was located in the Powder River Basin of Wyoming, which sold at a significant discount to a major market such as Henry Hub. Colorado Interstate Gas Pipeline s system is the major pricing location for our Powder River natural gas production.

With the beginning of our Texas production operations in the third quarter of 2004, the majority of our near term production is from Texas. For the nine months ended September 30, 2005, natural gas production from our East Texas properties accounted for approximately 72% of our total natural gas production. Natural gas prices for our Hilltop area production will generally be priced based on prices at the Katy, Texas regional hub. Although monthly variances occur in the price differentials between Katy Hub prices and Henry Hub prices, Katy Hub prices generally trade at a small discount to Henry Hub prices. Our Deep Bossier production generally is priced based on Katy Hub prices less gathering, processing and transportation fees.

Crude oil prices increased in 2004 due to perceived tight crude supplies, the continued conflict in Iraq, and increasing global demand lead by increased Asian demand for commodities, in particular energy-related commodities. Average crude oil prices in 2004 were significantly higher than the average 2003 prices. While substantially all of our production is natural gas, high crude prices help keep natural gas prices high by keeping alternative fuels, such as heating oil and residual fuel, expensive.

During early 2005, crude oil prices continued to firm, reaching prices not seen in many years. Continuing tightness of supply, stronger than expected economic growth and less sensitivity to higher energy prices in major global economies (United States, Europe and Asia) were credited with being the prime factors in higher sustained crude oil prices. The higher crude oil prices continued to support higher natural gas prices even though natural gas continued to trade at less than parity on an energy equivalent basis to crude oil. We have limited crude oil production, which is located in the Appalachian Basin of West Virginia. Crude sales are made to local purchasers and prices received are based on the Ergon posted price for West Virginia, adjusted for quality and transportation.

We do not currently have any financial derivative or hedge positions on any of our future natural gas and oil sales. All natural gas and oil sales are either sold directly in spot markets or sold through marketing or sales contracts priced at daily or monthly spot prices.

Liquidity and Capital Resources

During the nine months ended September 30, 2005, we raised $90.5 million, before fees and expenses, from various debt and equity financings, repaid $26.5 million of outstanding senior notes and expended approximately $81.2 million in cash on natural gas and oil properties. At September 30, 2005, approximately $8.5 million remained in available cash for future capital commitments. For a more detailed discussion regarding our significant debt arrangements and covenants, see Description of Indebtedness .

On June 17, 2005, the Company completed the private placement of $63.0 million of senior secured notes bearing interest at three month LIBOR plus 6%. The notes mature on June 18, 2010. Concurrently with the private placement of senior secured notes, we closed the acquisition of additional leasehold and working interest properties from Geostar in the Hilltop area of East Texas and in the Powder River Basin of Wyoming and Montana. We paid a total of $68.5 million for the interests acquired from Geostar consisting of $30.5 million in cash, 1,650,133 common shares valued at CDN$4.50 per share and $32.0 million in unsecured subordinated notes maturing on January 31, 2006.

On June 30, 2005, we completed a private placement of 6,617,736 common shares at CDN$3.31 per share. The estimated net proceeds from this placement were $16.4 million (CDN$20.5 million), after deducting placement fees and expenses.

On August 11, 2005, we executed an agreement with Geostar whereby the Geostar $32.0 million unsecured subordinated note was cancelled. In conjunction with the note cancellation, we agreed to issue Geostar 6,373,694 common shares and a new unsecured subordinated note for $15.0 million. The new Geostar note bears interest, payable monthly commencing February 15, 2006, at three-month LIBOR plus 4.5%. Pursuant to the terms of the Geostar agreement, we will utilize a portion of the proceeds of the Chesapeake transaction to pay the Geostar note in full.

On September 19, 2005, we issued to the holders of our senior secured notes an additional $10.0 million of senior secured notes on substantially the same terms as the original June 2005 private placement, including the issuance of 206,354 common shares to the note holders. The common shares issued in the transaction represented an aggregate value of CDN$714,286 based upon the five day weighted average trading price of CDN$3.4615 per share for the five trading days immediately prior to closing. In connection with the sale of the additional notes, we issued subscription receipts to the purchasers of the notes, for no additional consideration, entitling the holders to receive common shares in CDN$714,286 increments on each of the six, twelve and eighteen-month anniversaries of the closing date, valued on a five day weighted average trading price immediately prior to the date of issuance.

We have the right, exercisable quarterly to June 16, 2007, to require the original purchasers of the senior secured notes to purchase additional notes in an amount limited to an aggregate of $10.0 million in principal, provided that we comply with proved plus probable reserve PV(10) value to net senior secured debt coverage ratio of 2.0:1 and other general covenants and conditions. The PV(10) value is to be based on a third party independent reserve report utilizing constant pricing based on the lower of current natural gas and oil prices, adjusted for area basis differentials, or $6.00 per Mcf of natural gas and $40.00 per barrel of oil. The senior secured notes prohibit us from issuing any debt senior to these notes.

On November 4, 2005, we closed the Chesapeake transaction resulting in us receiving approximately $83.8 million, before fees and expenses, in conjunction with the issuance of new common shares and Deep Bossier partial leasehold working interest sale. Chesapeake agreed to pay 44.44% of the drilling costs through casing point in the first six wells drilled by the parties in the Hilltop prospect to a depth sufficient to test the Deep Bossier formation (an approximate depth of 19,000 feet) in order to earn its 33.33% leasehold working interest. We plan to use the proceeds from the transaction as well as other sources to accelerate drilling activities, to reduce short term debt and for general corporate purposes. For additional information, see Business-Natural Gas and Oil Operations-Transaction with Chesapeake Energy Corporation.

We continually evaluate our capital needs and compare them to our capital resources. To execute our operational plans, particularly our drilling plans in East Texas, additional funds will be needed for acreage acquisition, seismic and other geologic analysis, drilling, undertaking completion activities and for general corporate purposes. Our current budgeted capital expenditures for the next twelve months is approximately $50.0 million. We may have to significantly reduce our drilling and development program if our internally generated cash flow from operations and cash flow from financing activities are not sufficient to pay debt service and expenditures associated with our projected drilling and development activities. We expect to fund these expenditures from internally generated cash flow, cash on hand, the issuance of additional senior secured notes or the issuance of additional equity. We may also attempt to balance future capital expenditures through joint venture development of certain properties with industry partners. We are in the early stages of exploration and development of our East Texas properties. Amounts and timing of future cash flows is dependent on confirmation of production from recently completed wells, together with the success of currently drilling and to be drilled wells. We cannot be certain that future funds will be available to fully execute our business plan. During 2004 and continuing into 2005, the availability of capital for companies in the energy industry has been high. Given the continued forecasts for high natural gas and oil prices and our recent debt and equity financings, we believe that sufficient cash will be available to execute our business and operational plans for at least the next 12 months.

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 and result in a financial covenant default under the senior secured notes. Likewise, a material decrease in current and projected natural gas prices could also impact our ability to divest ourselves of certain non-core assets. This could impact our ability to fund future activities. Under the terms of our senior secured notes, the proceeds from asset sales must first be offered to the holders of the senior secured notes as repayment of outstanding debt.

We currently have no natural gas price financial instruments or hedges in place. Similarly, we have no financial derivatives. Our natural gas marketing contracts use spot market prices. Given the uncertainty of the timing and volumes of our natural gas production this year, we do not currently plan to enter into any long term fixed-price natural gas contracts, swap or hedge positions, other gas financial instruments or financial derivatives in 2005. Further, the senior secured notes covenants restrict us from hedging more than 50% of future production.

We have no off-balance sheet arrangements and have no plans to enter into any at this time.

At September 30, 2005, we were in compliance with all debt covenants.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses, contingent assets and liabilities and the related disclosures in the accompanying financial statements. Changes in these estimates and assumptions could materially affect our financial position, results of operations or cash flows. Management considers an accounting estimate to be critical if:

- It requires assumptions to be made that were uncertain at the time the estimate was made; and
- Changes in the estimate or different estimates that could have been selected could have a material impact on our consolidated results of operations or financial condition.

All other significant accounting policies that we employ are presented in the notes to the consolidated financial statements. The following discussion presents information about the nature of our most critical accounting estimates, our assumptions or approach used and the effects of hypothetical changes in the material assumptions used to develop each estimate.

Nature of Critical Estimate Item: Oil and Natural Gas Reserves Our estimate of proved reserves is based on the quantities of oil and gas which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in the future years from known reservoirs under existing economic and operating conditions. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation, and judgment. For example, we must estimate the amount and timing of future operating costs, severance taxes, development costs, and workover costs, all of which may in fact vary considerably from actual results. In addition, as prices and cost levels change from year to year, the economics of producing the reserves may change and therefore the estimate of proved reserves also may change. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves. Despite the inherent imprecision in these engineering estimates, our proved reserve volumes and values are used to calculate depletion and impairment provisions, respectively.

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Assumptions/Approach Used: Units-of-production method to amortize our oil and natural gas properties The quantity of reserves could significantly impact our depletion expense. Any reduction in proved reserves without a corresponding reduction in capitalized costs will increase the depletion rate.

Ceiling Limitation Test The full-cost method of accounting for oil and gas properties requires a quarterly calculation of a limitation on capitalized costs, often referred to as a full-cost ceiling calculation. The ceiling is the discounted present value of our estimated total proved reserves adjusted for taxes using a 10% discount rate. To the extent that our capitalized costs (net of accumulated depletion and deferred taxes) exceed the ceiling, the excess must be written off to expense. Once incurred, this impairment of oil and gas properties is not reversible at a later date even if oil and gas prices increase. Impairments were required in the years ended December 31, 2004, 2003, and 2002. Additional impairments were recorded during the first and second quarters of 2005 but no ceiling impairment was required during the third quarter of 2005. The calculation of our proved reserves could significantly impact our ceiling limitation used in determining whether an impairment of our capitalized costs is necessary. The ceiling calculation dictates that prices and costs in effect as of the last day of the period are generally held constant indefinitely. Therefore, the future net revenues associated with the estimated proved reserves are not based on our assessment of future prices or costs, but rather are based on prices and costs in effect as of the end of the period. Oil and natural gas prices before basis adjustments used in the reserve valuation at September 30, 2005 and December 31, 2004 were $64.67 per barrel and $9.86 per Mcf and $27.38 per barrel and $4.98 per Mcf, respectively.

Effect if different assumptions used: Units-of-production method to amortize our oil and natural gas properties A 10% increase or decrease in reserves would have increased or decreased our depletion expense for the nine months ended September 30, 2005 by approximately 3%. A 10% increase or decrease in reserves for the year ended December 31, 2004 would have increased or decreased our depletion expense by approximately 5% with an offsetting adjustment to ceiling impairment.

Ceiling Limitation Test The most likely factor to contribute to a ceiling test impairment is the price used to calculate the reserve limitation threshold. A significant reduction in the prices at a future measurement date could trigger a full-cost ceiling impairment. At September 30, 2005, we had a ceiling limitation cushion of approximately $39.3 million. A 10% increase or decrease in prices used would have increased or decreased our cushion by approximately 56%. Another likely factor to contribute to a ceiling test impairment is a revised estimate of reserve volume. A 10% increase or decrease in reserve volume would have increased or decreased our cushion by approximately 34% at September 30, 2005. A 10% increase in reserve volume at December 31, 2004 would have decreased our depletion expense by approximately 5% while a 10% decrease in reserve volume would have increased depletion expense by approximately 6%. The 10% change resulting from an increase or decrease in 2004 reserve volume would be partially offset by a change in impairment expense.

Nature of Critical Estimate Item: Unproved Property Impairment We have elected to use the full-cost method to account for our oil and gas activities. Investments in unproved properties are not amortized until proved reserves associated with the properties can be determined or until impairment occurs. Unproved properties are evaluated quarterly for impairment on a field basis. If the results of an assessment indicate that an unproved property is impaired, the amount of impairment is added to the proved oil and natural gas property costs to be amortized.

Assumptions/Approach Used: At September 30, 2005, we had $71.6 million allocated to unproved property costs which was comprised of drilling in process costs of $18.6 million and unevaluated acreage costs of $53.0 million. At December 31, 2004, we had $29.8 million allocated to unproved property costs which was comprised of drilling in process costs of $12.9 million and unevaluated acreage costs of $16.9 million The unproven property costs are evaluated by the technical team and management of whether the property has potential attributable reserves. Therefore, the assessment made by our technical team and management of the potential reserves will determine whether costs are moved from the unproved category to the full-cost pool for depletion or whether an impairment is taken.

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Effect if different assumptions used: A 10% increase or decrease in the unproved property balance would have increased or decreased our depletion expense by approximately 2% for the nine month period ended September 30, 2005. A 10% increase or decrease in unproved would have increased or decreased the impairment expense for the nine months ended September 30, 2005 by approximately 82% and for the year ended December 31, 2004 by approximately 47%.

Nature of Critical Estimate Item: Asset Retirement Obligations We have certain obligations to remove tangible equipment and restore land at the end of oil and gas production operations. Our removal and restoration obligations are primarily associated with plugging and abandoning wells. Previously, the costs associated with this activity were capitalized to the full-cost pool and charged to income through depletion. We adopted Statement of Financial Accounting Standards (SFAS) No. 143, *Accounting for Asset Retirement Obligations* effective January 1, 2003, as discussed in Note 2 to our Consolidated Financial Statements. SFAS No. 143 significantly changed the method of accruing for costs an entity is legally obligated to incur related to the retirement of fixed assets (asset retirement obligations or ARO). Primarily, the new statement requires us to estimate asset retirement costs for all of our assets, inflation adjust those costs to the forecast abandonment date, discount that amount using a credit-adjusted-risk-free rate back to the date we acquired the asset or obligation to retire the asset and record an ARO liability in that amount with a corresponding addition to our asset value. We then accrete the liability quarterly using the period-end effective credit-adjusted-risk-free rate. As new wells are drilled or purchased, their initial asset retirement cost and liability is calculated and recorded. Should either the estimated life or the estimated abandonment costs of a property change upon our quarterly review, a new calculation is performed using the same methodology of taking the abandonment cost and inflating it forward to its abandonment date and then discounting it back to the present using our credit-adjusted-risk-free rate. The carrying value of the asset retirement obligation is adjusted to the newly calculated value, with a corresponding offsetting adjustment to the asset retirement cost (included in the full-cost pool); therefore, abandonment costs will almost always approximate the estimate. When wells are sold the related liability and asset costs are removed from the Balance Sheet.

Assumptions/Approach Used: Estimating the future asset removal costs is difficult and requires management to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. Inherent in the estimate of the present value calculation of our AROs are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit-adjusted-risk-free-rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments.

Effect if different assumptions used: Since there are so many variables in estimating AROs, we attempt to limit the impact of management s judgment on certain of these variables by using input of qualified third parties. We engage Netherland, Sewell & Associates, Inc., independent petroleum engineers, to evaluate our properties annually, who has consented to the use of its name and reports in this registration statement. We use the remaining estimated useful life from the year-end reserve reports by our independent reserve engineer in estimating when abandonment could be expected for each property. We expect to see our calculations impacted significantly if interest rates move from their current lows, as the credit-adjusted-risk-free rate is one of the variables used on a quarterly basis. Our technical team developed a standard cost estimate based on historical costs, industry quotes and depth of wells. Unless we expect a well s plugging to be significantly different than a normal abandonment, we use this estimate. The resulting estimate, after application of a discount factor and some significant calculations, could differ from actual results, despite all our efforts to make an accurate estimate.

New accounting policies. In December of 2004, the Financial Accounting Standards Board (FASB) issued SFAS 123R, Share Based Payments which addresses the accounting for transactions in which an entity exchanges its equity instruments for goods and services. It also addresses transactions in which an entity incurs liabilities in exchange for goods or services that are based on the fair value of the entity s equity instruments or that may be settled by the issuance of those equity instruments. This statement is a revision of FASB No. 123,

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Accounting for Stock-Based Compensation (SFAS No. 123). This statement supersedes APB Opinion No. 25, Accounting for Stock Issued to Employees . Among other things, this statement requires a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. That cost is recognized over the period during which an employee is required to provide service in exchange for the award the requisite service period (usually the vesting period). This statement is to be applied as of the beginning of the first interim or annual period that begins after December 15, 2005, but earlier adoption is encouraged. Because the Company has adopted SFAS123 and recorded the fair value of stock options granted after January 1, 2003, this new standard will have minimal impact.

In December of 2004, FASB issued SFAS No. 153, Exchanges of Nonmonetary Assets An Amendment of APB Opinion No. 29 (SFAS No. 153). The guidance in APB Opinion No. 29, Accounting for Nonmonetary Transactions (APB Opinion No. 29) is based on the principle that exchanges of nonmonetary assets should be measured based on the fair value of the assets exchanged. The guidance in that APB Opinion No. 29; however, included certain exceptions to that principle. This Statement amends APB Opinion No. 29 to eliminate the exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. The provisions of this Statement are effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. Earlier application is permitted for nonmonetary asset exchanges occurring in fiscal periods beginning after the date this Statement is issued. The provisions of this Statement shall be applied prospectively. The adoption of SFAS No. 153 did not have any impact on our financial statements.

Quantitative and Qualitative Disclosure 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 region produced. Prices received for natural gas are volatile and unpredictable and are beyond our control. For the year ended December 31, 2004, a 10% change in the prices received for natural gas production would have had an approximate $600,000 impact on our revenues. As a result of production and price increases in 2005, a 10% change in prices received for natural gas production would have an approximate $1.7 million impact on our revenues.

Interest Rate Risk. The carrying value of our debt approximates fair value. At December 31, 2004, we had fixed interest rates on 100% of its long term debt at fixed rates of 10% to 15%. At September 30, 2005, we had approximately $88.0 million of long term debt subject to floating interest rates. Of this debt, $73.0 million of the senior secured notes was at LIBOR plus 6% and the remaining Geostar note payable of $15.0 million was at LIBOR plus 4.5%. A 10% fluctuation in interest rates would have an approximate $381,000 impact on annual interest expense.

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.

Contractual Obligations and Contingencies

Our contractual obligations as of December 31, 2004 consisted of the following:

	As of December 31,				
	2005	2006-2008	2009-2010	After 2010	Total
			(in thousands)		
Long term debt	$	$ 26,483	$ 33,250	$	$ 59,733
Operating leases	532	532			1,064
Total	$ 532	$ 27,015	$ 33,250	$	$ 60,797

Our contractual obligations as of September 30, 2005 consisted of the following:

	As of September 30,				
	2005	2006-2008	2009-2010	After 2010	Total
Long term debt, including related current portion	$ 15,000(1)	$	$ 106,250	$	$ 121,250
Operating leases	196	730			926
Total	$ 15,196	$ 730	$ 106,250	$	$ 122,176

(1) Pursuant to the terms of the Geostar agreement, we will utilize a portion of the proceeds of the Chesapeake transaction to pay the Geostar note in full.

Off-Balance Sheet Arrangements

As of December 31, 2004, we had no off-balance sheet arrangements. We have no plans to enter into any off-balance sheet arrangements in the foreseeable future.

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BUSINESS

Our Business

We are an independent energy company engaged in the exploration, development and production of natural gas and oil in the United States and Australia. Our principal business activities include the identification, acquisition, and subsequent exploration and development of natural gas and oil properties. Our emphasis is on prospective deep structures identified through seismic and other analytical techniques as well as unconventional natural gas reserves, such as coal bed methane. We seek to reduce exploration risk and financial exposure by acquiring properties that have wells previously drilled in close proximity or into the targeted geologic horizons, joint venturing with knowledgeable industry partners or by farming out acreage to other industry participants on terms that reduce our economic risk to levels deemed appropriate. Our current areas for natural gas or oil activities are:

- Deep Bossier play in East Texas;
- Powder River Basin in Wyoming and Montana;
- Gunnedah Basin in New South Wales, Australia;
- Gippsland Basin in Victoria, Australia;
- Appalachian Basin in West Virginia;
- San Joaquin Basin in California; and
- Cherokee Basin in Southeast Kansas.

We currently are pursuing conventional natural gas exploration in the Deep Bossier play in the Hilltop area in East Texas and the Appalachian Basin in West Virginia. As of September 30, 2005, we had leases on approximately 51,800 gross acres (34,000 net) in Texas and approximately 26,700 gross acres (13,300 net) in Appalachia. For the nine months ended September 30, 2005, our daily production from the Hilltop area averaged approximately 6.9 MMcfed, and from the Appalachian Basin, it averaged 0.1 MMcfed.

In our coal bed methane, or CBM, projects, we use industry technologies to assist us in developing commercial natural gas production from known coal beds. Our primary CBM properties are in the United States in the Powder River Basin and in the Gunnedah and Gippsland Basins of Australia. As of September 30, 2005, our acreage position in the Powder River Basin was approximately 55,800 gross acres (21,600 net), and our Australian acreage totaled approximately 3.4 million gross acres (1.8 million net). For the nine months ended September 30, 2005, our average daily production from our CBM properties in the Powder River Basin was approximately 2.6 MMcfed. Exploration and long term production testing on our Australian CBM properties is currently underway. Thus, we currently have no natural gas sales from our Australian CBM properties.

Our Strategy

Management believes that:

- Natural gas is an environmentally friendly fuel that will be increasingly valued in the United States and Australia;
- CBM projects provide us with lower risk exposure to long-lived natural gas production and reserves;
- We have made a significant natural gas discovery in the Deep Bossier play in the Hilltop area of East Texas that will require additional exploration and development;
- We have the ability to assemble the technical and commercial and resources needed to pursue these potential projects; and

Our successful development of one or more large potential natural gas projects will create substantial shareholder value.

Based on these beliefs, we have pursued a strategy that includes:

Accelerating exploration and development drilling on our Deep Bossier play in East Texas;

Combining lower risk CBM projects, such as the Powder River Basin and Australia, with higher risk conventional natural gas exploration;

Assembling a portfolio of high-potential natural gas exploration and development projects in the East Texas and Appalachian Basins; and

Limiting capital commitments and reducing risk by maintaining financial flexibility through accessing various sources of capital and monetizing certain assets through joint venture arrangements with industry participants.

Natural Gas and Oil Operations

The following provides an overview of our significant natural gas and oil projects. While actively pursuing specific exploration and exploitation activities in each of the following areas, we are continually reviewing additional opportunities. There is no assurance that new drilling opportunities will continue to be identified or that any new drilling opportunities will be successful if drilled.

Geostar Acquisition

Concurrently with the private placement of senior secured notes on June 17, 2005, we closed the acquisition from Geostar of additional leasehold and working interest properties in the Hilltop area of East Texas and in the Powder River Basin of Wyoming and Montana. We paid, before purchase price adjustments and acquisition costs, $68.5 million for the interests acquired from Geostar consisting of $30.5 million in cash, 1,650,133 common shares valued at CDN$4.50 per share and $32.0 million in unsecured subordinated notes maturing on January 31, 2006. Based on a third party evaluation, the Geostar acquisition included 3.0 Bcfe of proven developed reserves and 12.6 Bcfe of proven undeveloped reserves and additional working interest in unproven acreage in the Hilltop and Powder River Basin areas. The acquisition increased our working interest position in the Hilltop area from an average of over 70% to an average of over 90% and gave us operational control of the properties. The acquisition of additional Powder River Basin interests increased our average working interest position from approximately 17% to approximately 38% in properties currently being developed through an existing joint venture. For additional information on proved reserves of Geostar acquisition, see unaudited Notes to the Unaudited Pro Forma Financial Statements on page F-55.

On August 11, 2005, we executed an agreement with Geostar whereby the Geostar $32.0 million unsecured subordinated note was cancelled. In conjunction with the note cancellation, we agreed to issue Geostar $17.0 million of our common shares issued at a value of CDN$3.25 and a new unsecured subordinated note for $15.0 million. The new Geostar note bears interest, payable monthly commencing February 15, 2006, at three-month LIBOR plus 4.5% and matures November 15, 2006. The note requires monthly principal payments of $1.5 million commencing February 15, 2006 and continuing for nine months thereafter with a final principal payment of $1.5 million due on November 15, 2006. We may elect to pay interest in kind through the issuance of additional notes with such notes maturing on January 15, 2007. Pursuant to the terms of the Geostar agreement, we will utilize a portion of the proceeds of the Chesapeake transaction to pay the Geostar note in full.

Hilltop Area, East Texas

General. As of September 30, 2005, we have approximately 51,800 gross acres (34,000 net) in the Deep Bossier play in the Hilltop area, located approximately midway between Dallas and Houston in East Texas. Wells in this area target multiple potentially productive natural gas geologic horizons. Deep Bossier sand wells

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are typically characterized by high initial production, significant decline rates and long-lived reserves. The development of effective hydraulic formation fracturing, or frac, techniques has allowed operators to develop significant reserves in the Deep Bossier sand intervals. Our acreage is located in an area within the East Texas Basin where the Deep Bossier sand is encountered at greater depths with possibly thicker pay zones than the typical Deep Bossier sand development that has been experienced by other industry participants.

Geology. The East Texas Basin is characterized by numerous shallow and deeper productive horizons. The basin has been the site of natural gas and oil activity since the earliest days of the U.S. natural gas and oil industry. The Deep Bossier sand formation that we are targeting was not considered prospective until our activities together with the drilling of a nearby well ignited a high level of interest in this formation. To our knowledge, prior to our initial drilling activities in 2001, no wells had been drilled specifically for Deep Bossier sand production in East Texas. Our geoscientists developed the Deep Bossier sand prospect focusing on two deep wells drilled in the early 1980s. Those wells encountered over-pressured, gas-charged reservoirs in the Bossier shale section and were unable to reach the intended targets. Our geoscientists formulated a depositional model to explain the presence of these high-quality sands in an area previously believed to be too remote from the traditional sand sources for the East Texas Basin. We believe that the wells drilled to date are, in general, supporting this depositional model.

Gas Transportation. Given the high level of traditional natural gas and oil activities in the East Texas Basin, the area has extensive natural gas pipeline infrastructure in place. In July 2004, a new one Bcf per day natural gas transmission pipeline was constructed by a third party within approximately three miles from our initial drilling activities. We have contracted with this third party for an initial 50.0 MMcfd of capacity and are negotiating an increase in that amount. Our current production from the Hilltop area is being processed at the producing well sites and is being transported to the Katy Hub in Katy, Texas, where numerous parties are available to purchase the natural gas.

Activities. In 2001, we participated in the 21,000 foot Belin Trust A-1 well. In January 2003, Geostar took over as operator of the Belin Trust A-1 well. Geostar attempted a completion in a Deep Bossier sand (approximately 18,512 feet to 18,610 feet) and was encouraged by the initial test results. A fracture stimulation and other downhole treatment techniques were performed. The well briefly tested pipeline quality natural gas at short term rates up to 5 MMcfd before experiencing mechanical casing problems. The well was ultimately plugged and abandoned due to safety concerns.

Due to the encouraging results from the Belin Trust A-1 well and the results of several earlier wells drilled in the area, we announced in September 2003, that we had begun site operations on the F-K #1 well in Leon County, Texas. As a 75% working interest owner, we drilled the F-K #1 well to a projected depth of 19,175 feet. In September 2004, the F-K #1 well began production with initial production rates of 15.0 MMcfd (8.5 MMcfd net). We now have a 98% working interest in the F-K #1 well as a result of the Geostar acquisition. Current production is approximately 4.1 MMcfd (3.1 MMcfd net).

The Cheney #1 well was drilled in the Hilltop area to test the Deep Bossier sand encountered in the F-K #1 well. This well is approximately one mile north of the F-K #1 well. The Cheney #1 well encountered approximately 400 net feet of potential pay based on natural gas shows while drilling and on logs. The well commenced production in mid-February 2005 at an initial rate of approximately 7.0 MMcfd (4.0 MMcfd net). As a result of the Geostar acquisition, our working interest in the Cheney #1 increased from 75% to 98%. Current daily production is approximately 0.9 MMcfd (0.7 MMcfd net) after stimulation in August 2005. We built a pipeline connecting the F-K #1 well and the Cheney #1 well site to an existing pipeline system that moves production to a major natural gas hub at Katy, Texas.

In early May 2005, as a 73% working interest owner, we completed the drilling of our third Deep Bossier sand well in East Texas, the Lone Oak Ranch #1 well. The well is located approximately three miles north northwest of the F-K #1 well and approximately two miles northwest of the Cheney #1 well. The Lone Oak Ranch #1 well was drilled to target expanded Upper and Middle Bossier sections and will also test for the deeper Bossier sand encountered on the Hilltop structure in the F-K #1 and Belin Trust #1-A wells. We now have a 98% working interest in the Lone Oak Ranch #1 well as a result of the Geostar acquisition. An unrelated private exploration and production company has a 25% after payout back-in interest in the Lone Oak Ranch #1 well. As a result of the Geostar acquisition, we will hold an after payout working interest of 69% in the Lone Oak Ranch #1 well. In addition to exploring additional acreage in the Hilltop area, this well completed our obligations to earn a 56.25% working interest (approximately 75% post-Geostar acquisition) in approximately 8,000 gross acres in the Hilltop area of East Texas, including acreage that directly offsets the F-K #1 well. Current daily production is approximately 2.1 MMcfd (1.6 MMcfd net).

We began drilling the Greer #1 well, our fourth Deep Bossier sand well in the Hilltop area in January 2005. The Greer #1 well is located approximately one mile from the F-K #1 well. We drilled the Greer #1 well to a total depth of 17,800 feet and, based on gas shows during drilling and electric logs, the well encountered approximately 57 net feet of apparent pay. As a result of the Geostar acquisition, we increased our working interest in this well from 73% to 98%. The well commenced production in July 2005 at an initial gross sales rate of approximately 5.0 MMcfd (3.9 MMcfd net). Current daily production is approximately 1.9 MMcfd (1.5 MMcfd net).

Drilling commenced in February 2005 on the Fridkin-Kaufman #2, or F-K #2, well to a total depth of 18,700 feet. Based on electric logs, the well encountered approximately 74 net feet of apparent pay in the Bossier lower K sand below 18,000 feet. The well encountered over 120 feet of indicated pay in the shallower Travis Peak formation. The well is located approximately 2,200 feet from the F-K #1 well. The completion attempt in the Bossier sands was not successful. A completion attempt in the Travis Peak was made in October 2005, and current production results are being evaluated. As a result of the Geostar acquisition, our working interest in the F-K #2 increased from 78% to 100%.

We commenced drilling the Donelson #1 well in May 2005. This sixth Deep Bossier well in the Hilltop area of East Texas was drilled to a total depth of 19,200 feet. The well has encountered an apparent commercial gas discovery in the Pettet formation at approximately 10,000 feet. In addition, the Donelson #1 well has encountered a productive interval within the Knowles limestone. A dedicated Knowles well will be drilled on the Donelson #1 location in order to accelerate the development and production of the Knowles formation and to take advantage of current high natural gas prices. The Donelson #1 well also encountered apparently productive sands in the upper and middle Bossier formations along with a series of apparently productive pay zones in the lower or deep Bossier formation from approximately 17,000 feet to 19,000 feet. The lower Bossier sands appear to correlate to a similar series of sands discovered by us in the earlier Belin Trust A-1 well. We will undertake a completion in the lower Bossier pays immediately after the dedicated Knowles well is drilled. The Donelson Knowles well was spudded in early November 2005 and will require approximately 45 days to drill and complete. As a result of the Geostar acquisition our working interest in this well increased from 78% to 100%.

We have contracted with a third party to provide us with two 20.0 MMcfd on-site processing facilities for our East Texas properties. For a monthly rental fee of approximately $35,000 per facility, the third party constructs and operates the natural gas processing plants. To date, our natural gas processing plants have operated with mechanical downtime of less than 12 hours per month. Current natural gas processing plant capacity is not anticipated to be reached until later in 2006. Prior to reaching current plant capacity, we anticipate contracting with a third party to construct and operate additional needed plants for a similar monthly fee. Lead time to construct a new natural gas processing plant is approximately 60 to 90 days.

We are currently conducting extensive seismic analysis of the available Hilltop seismic data and continue to refine our geologic model of the area. We have also begun permitting a large scale 3-D seismic survey that will cover the majority of our acreage in the Hilltop area in order to better define and understand the complex geology associated with the deposition of the Deep Bossier sand in the area. The 3-D survey will also evaluate the Lone Oak Ranch area and the numerous locations similar to other Bossier play wells. We are also planning the drilling of additional deep wells, and we plan to continue to acquire new leases in the area.

Our operations were not impacted by recent hurricane activity in the Gulf Coast area. Natural gas and oil prices have increased as a result of facility damages throughout the impacted area, which curtailed other Gulf Coast production.

Transaction with Chesapeake Energy Corporation

On November 4, 2005, we closed a transaction with Chesapeake Energy Corporation whereby Chesapeake:

- Acquired approximately 27.2 million newly issued common shares from us equal to 19.9% of its then outstanding common shares for $76.0 million (CDN$89.9 million) in cash or CDN$3.31 per share, before fees and expenses;
- Acquired a 33.33% working interest in our Deep Bossier play in the Hilltop prospect area of Leon and Robertson Counties of East Texas; and
- Formed an area of mutual interest to explore jointly in 13 counties in East Texas.

After reflecting the issue of common shares to Chesapeake, we have approximately 163.6 million common shares outstanding. Chesapeake has been granted registration rights for the shares issued pursuant to this transaction. Chesapeake also has the right, with certain exceptions, to maintain its percentage ownership on a fully diluted basis by participating in future stock issuances and has the right to an observer being present at meetings of the Board of Directors.

As part of this transaction, Chesapeake agreed to pay approximately $7.8 million, before fees and expenses, to acquire the shares described above and to pay a disproportionate amount off future drilling costs described below, in exchange for an undivided 33.33% of our leasehold working interests in the Deep Bossier Hilltop prospect, less and except 160 acres surrounding each of our existing well bores. Chesapeake agreed to pay 44.44% of the drilling costs through casing point in the first six wells drilled by the parties in the Hilltop prospect to a depth sufficient to test the Deep Bossier formation (an approximate depth of 19,000 feet) in order to earn its 33.33% leasehold working interest. Further, Chesapeake has agreed to provide one to two additional drilling rigs to us in 2006 if needed to accelerate drilling in the Hilltop Prospect.

The transaction also provided for the formation of an area of mutual interest, or AMI, covering all of Leon, Robertson, Houston, Cherokee, Madison, Anderson, Angelina, Nacogdoches, Trinity, Polk, Shelby, San Augustine and Sabine Counties in East Texas (the AMI Area). For a period of three years from November 4, 2005, we will offer Chesapeake the exclusive first right to purchase up to an undivided 50% of any leasehold/working interest rights acquired by us in the AMI Area on pre-determined terms. The AMI is one-way Chesapeake will not be obligated to present us any interests it now owns or acquires in the future in the AMI Area.

In connection with the transaction, we notified Chesapeake of a recent claim made by a third party that it has a right to purchase 33.33% of our interests in certain oil and gas leases located in Leon and Robertson Counties, Texas pursuant to a preferential right provision of an operating agreement dated July 7, 2000. On October 31, 2005, the third party filed a related petition for breach of contract and declaratory judgment in a legal action, as Navasota Resources, L.P. vs. First Source Texas, Inc., First Source Gas L.P., and Gastar Exploration Ltd. (Cause No. 0-05-451), in the District Court of Leon County, Texas, 12th Judicial District. We contend, among other things, that the claimant neither properly nor timely exercised any preferential right election it may have had with respect to the inter-dependent transactions. Accordingly, we intend to vigorously defend the claims.

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Pursuant to the terms of the Geostar agreement, we will utilize a portion of the proceeds of the Chesapeake transaction to pay the Geostar note in full.

Appalachian Basin, West Virginia

General. The Appalachian Basin is a proven hydrocarbon basin with substantial production history. The well developed infrastructure and proximity to major natural gas markets in this area result in gas prices generally exceeding Henry Hub gas prices, the standard for pricing NYMEX natural gas contracts. While numerous potential hydrocarbon horizons exist, we are focusing our West Virginia plans primarily on three potentially productive horizons: shallow conventional sands; the deep Trenton-Black River and fractured medium depth Devonian shales.

Shallow Conventional Gas. We have participated in 11 pilot wells drilled into shallow conventional gas sands. The Venango (Upper Devonian age) hydrocarbon horizon, including the primary targets of the Fifty-foot Sand, the Fifth Sand and the Gordon Sand, is a multiple horizon sand located at depths of generally less than 5,000 feet. The drilling of these horizons is relatively fast and inexpensive.

Trenton-Black River Deep Gas. The Trenton-Black River play was discovered in western New York where natural gas wells drilled to the Trenton-Black River formations produced at reported initial rates of approximately 5.0 to 8.0 MMcfd. The play was extended to southern central West Virginia when Trenton-Black River wells were drilled in the Roane County Cottontree Field.

The deep Trenton-Black River prospective formations and other deep geologic horizons can only be identified through the use of acquired or reprocessed seismic data. Geostar, the operator of the properties, has acquired and reprocessed available 2-D seismic data as well as acquired additional proprietary 2-D seismic data to identify these deep features. We control significant lease positions over several of these seismically defined features.

Fractured Devonian Shales. Since the beginning of Appalachian natural gas production, natural gas has been produced from various shale formations. Devonian shales are generally considered to be an unconventional natural gas reservoir. We are combining experience gained from CBM production with our seismic acquisition and processing analysis to attempt to determine areas where naturally occurring fracture systems potentially increase shale well productivity.

Activities. As part of our ongoing business activities, we are constantly reassessing the technical and commercial potential of our exploration acreage. As of September 30, 2005, we had approximately 26,700 gross acres (13,300 net) in the Appalachian Basin in West Virginia. We have acquired a small working interests in the Cross #1 well and the Hammack #1 well to increase our understanding of Trenton-Black River geology and geophysics. We have a 7.0% working interest in the Cross #1 well in the Cottontree Field located in Roane County, West Virginia and a 2.0% working interest in the Hammack #1 well in Roane County. The Cross #1 well is selling approximately 900 Mcfd (gross), and the Hammack #1 encountered no commercial natural gas.

East Lost Hills Field, San Joaquin Basin, California

General. The San Joaquin Basin of California is one of the most prolific hydrocarbon producing basins in the continental United States. The 14,000 square mile basin has produced an estimated 13 billion BOE and contains 25 fields classified as giant fields, each with cumulative production to date of more than 100 million barrels of oil equivalent.

Activities. On November 23, 1998, the Berkley-Bellevue ELH-1 well was drilled at a depth of 17,600 feet on the East Lost Hills structure. It blew out and ignited when it encountered high-pressure gas in the Deep Temblor horizon. It was reported that the blow-out well produced a significant amount of gas and liquids before it was eventually brought under control. While the Berkley-Bellevue ELH-1 well blew out when it encountered high-pressure gas in the Deep Temblor horizon, additional wells have been unsuccessful.

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Our California properties are located in the East Lost Hills field in Kern County, California. The ELH structure has an elongated oval shape that has a northwest to southeast orientation. Our properties are generally located along the northwest end of the ELH structure, where we have approximately 3,000 gross acres (3,000 net) on or near the ELH structure. We have no definitive plans to drill on our East Lost Hills acreage at this time; however, we are planning to evaluate the potential for shallower prospective formations on these leases.

Coal Bed Methane

Our acreage positions in the Powder River Basin and in Australia are primarily CBM plays. CBM is methane gas that is formed and stored in coal beds. The presence of methane in coal seams has been known since the mining of coal began. Until recently, CBM was considered a safety problem, and coal had to be degasified before subsurface coal mining could occur. In the last two decades, however, the natural gas industry has dramatically improved its technical understanding of CBM production techniques and CBM has come to be viewed as a major source of low cost methane.

CBM production is dissimilar to conventional natural gas production in several notable ways. Coal seams produce nearly pure methane gas while conventional natural gas wells normally produce natural gas that contains small portions of ethane, propane and other heavier hydrocarbon gases. Methane normally constitutes more than 90% of the total gases in the production from conventional natural gas wells. Also, because coal beds often contain substantial amounts of water, it is first necessary to produce water to lower the reservoir pressure to allow the CBM to be produced. Producing and properly handling the water from the coal beds is an important part of CBM production. Once produced, CBM is dried to remove any residual moisture, compressed to pipeline pressures and ultimately transported in the same interstate pipelines as natural gas from conventional natural gas fields. CBM is also sold to the same consumers and used in the same applications as natural gas produced from conventional wells.

Since the late 1970s, CBM has been produced commercially by drilling conventional well bores into coal beds. The first commercial CBM fields were developed in the high rank bituminous hard coal beds of Alabama, the Appalachian Mountains of Pennsylvania, Virginia, West Virginia, the San Juan Basin of Colorado and New Mexico. Limited commercial CBM production was established in 1989 in the lower rank, sub-bituminous soft coals of the Powder River Basin of Wyoming, CBM production from the Powder River Basin has increased substantially since that date.

CBM plays differ from conventional natural gas plays in several significant ways. The large size of coal beds tends to reduce geologic risks while the generally shallow depths of the coals can result in simple wells with relatively low drilling costs. CBM wells typically produce at lower rates and may have lower reserves per well than some conventional wells. The combination of large CBM deposits, relatively low geologic risk and low drilling costs make CBM plays some of the most attractive in the United States. Although the actual finding and development costs vary for each individual gas field, significant technical strides have been made in lowering CBM costs.

We are actively developing CBM properties in the Powder River Basin of Wyoming. We are also investigating CBM development plans in the Appalachian Basin of West Virginia, on Petroleum Exploration License 238, or PEL 238, in the Gunnedah Basin in New South Wales, Australia and in the Gippsland Basin in Victoria, Australia.

Powder River Basin, Wyoming and Montana

General. The Powder River Basin encompasses approximately 26,000 square miles of eastern Wyoming and southeastern Montana. The Wyoming Powder River Basin has been an important natural gas and oil producing area for nearly 100 years. Likewise, Wyoming has been a top producer of low-sulfur soft coal for many years. Only recently has a connection been made between the large coal reserves of the basin and natural gas production. Beginning in about 1989, Powder River Basin CBM development began in earnest and has increased

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dramatically in recent years. The drilling activity began about 40 miles south of Gillette, Wyoming and extended northward along the east flank of the basin and westward into the basin. Generally, CBM wells are shallow and less costly than conventional natural gas wells. Because of the widespread nature of multiple coal horizons, the geologic success rates reported by some operators in the Powder River Basin have been high. Due to these and other factors, the Powder River Basin CBM play has developed into one of the most active drilling areas in the United States. However, there is no assurance that we will achieve comparable cost or similar success rates.

Geology. Coal in the Powder River Basin is found in the relatively shallow Paleocene Fort Union Formation. This coal forms some of the thickest known coal seams in North America. During the 1960s and 1970s, exploration wells being drilled to deeper conventional natural target horizons encountered this coal and commonly experienced gas flows from the shallow coal formations. These wells generally yielded large volumes of water and little commercial natural gas. In some cases, blowouts occurred due to unexpected natural gas flows from the shallow coal zones.

Excellent micro-permeability helps explain why natural gas from the Powder River Basin coal is readily produced without costly artificial stimulation. Microscopic pathways facilitate the movement of CBM to open fractures, and through these fractures, CBM finds its way to the borehole. Fracturing of the coals is apparently common throughout the Powder River Basin. This is exemplified by the large and growing area of CBM production and the large number of natural gas flows from water wells drilled into or through coal formations. The fracturing of the coal beds is critical since it is the fractures in coal that provide pathways for natural gas migration and production. Gas produced from Powder River Basin coals generally has very high methane content, usually requiring no treatment to remove carbon dioxide or nitrogen.

Drilling Techniques. One of the main reasons for the rapid pace of activity in the Powder River Basin is the low cost of drilling to shallow depths, generally less than 1,200 feet, and the fact that the coal there normally does not require expensive fracture treatments to produce at economic rates. The standard procedure has been to drill to just above a coal formation, set casing, then air drill into the coal, under-ream the hole, circulate out cuttings, set a pump or install gas lift if water volumes dictate, and place the well on production. CBM wells are drilled in units or projects, with each well in the unit connected to a low-pressure gathering pipeline. The gathering line delivers produced natural gas and water to a central facility where water is disposed of and natural gas is compressed and metered for delivery through a sales line to a main gas transport pipeline. The water production from CBM wells varies substantially. Although subject to regulatory review and approval, produced water is usually fresh and has generally been disposed of in holding ponds and surface streams. Other disposal techniques, which are somewhat more expensive, such as re-injection into non-producing formations, have also been used to dispose produced water. Gathering and processing costs vary by well location, system design and take-away capacity. Properties that are close to major pipelines should have substantially lower gathering costs than more remote properties.

CBM Production. The typical CBM well in the Powder River Basin initially produces significant quantities of water. As the water is produced, natural gas production also begins slowly. Typically, after a considerable amount of water is produced over a three to six-month period or longer, gas production increases and water production decreases. In some cases, wells do not produce any significant amounts of water and begin producing gas immediately. This free gas is produced from fractures in the coal that are attributable to subtle structural folding or compaction of coals after they were deposited. As the development expands, the productive area increases as water is produced from these areas. Water production can also be reduced near the edges of the basin, especially near massive open pit coal mines. These shallow coals near the outcrops appear to be partially de-watered naturally due to the extensive surface mining and its associated water production.

Gas Transportation. Of critical importance to the success of a CBM project in the Powder River Basin is natural gas transportation to market. Major gas pipelines have been built into the basin to transport CBM to major interstate gas markets. The Thunder Creek, Fort Union, Bighorn and Western Gas Resources pipelines are the major pipelines flowing out of the south end of the basin. The Williston Basin Interstate pipeline runs north to Montana, then east to North Dakota, eventually connecting to the Northern Border pipeline and eastern markets.

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Western Gas Resources pipelines have access to both the south and north flowing pipelines. Each of our Powder River Basin properties has access to one or several of these pipelines. Additional pipeline capacity to both the north and south has been proposed to be built.

Gas sales prices vary with the market, but historically have been based on the prices posted by Colorado Interstate Gas. While prices generally track this index, when transportation capacity is fully utilized, Powder River Basin gas prices can be substantially depressed, which happened in the summer of 2002.

Activities. We now own an approximate 38% average working interest in 55,800 gross acres (21,600 net) in the Powder River Basin of Wyoming following the Geostar acquisition. Our main focus of activity is the Squaw Creek and adjacent areas, notably the Ring of Fire field. We currently have approximately 299 CBM wells producing in the Basin.

In 2003, we closed a Powder River Basin Earn-In Joint Venture with a third party who paid approximately $6.7 million and made a spending commitment of $14.5 million and became operator. We assigned the operator 66% of our interest in all of our existing producing and non-producing leases within the area of mutual interest. Under the agreement, the operator acquired an interest equal to 50% of our interests. The operator receives 60% of all pre-tax cash flow as defined in the agreement until it recovers its share of the $14.5 million spending commitment amount. We are 50/50 joint venture partners with the operator for new CBM exploration and development activity within the AMI. In the third quarter of 2004, we exercised our option to invest additional funds to maintain our working interest ownership in any wells drilled after the spending commitment was met and will continue to invest in the Powder River Basin.

In 2004, approximately 117 wells were drilled under the joint venture. Of the new wells drilled, approximately 112 were on production in the second quarter of 2005. Pinnacle continues to drill under the joint venture agreement. We have chosen to fund our working interest ownership in any wells drilled after the spending commitment was met.

We have drilled 17 pilot test CBM wells in the Fence Creek area, but the project area is not currently connected to a natural gas pipeline. The operator has informed our management that it is currently evaluating potential natural gas gathering infrastructure options to allow development of the Fence Creek area.

Gunnedah Basin, New South Wales, Australia

General. PEL 238 is an approximately 2.0 million gross acres (700,000 net acres) CBM property located approximately 250 miles northwest of Sydney, Australia, in the Gunnedah Basin of New South Wales. The Gunnedah Basin s characteristics include porous permeable quartzose sandstones at several stratigraphic levels that are adjacent to mature organic reservoir rocks that are age equivalents of producing formations in the other producing regions of Eastern Australia. CBM potential is also high, as previous wells and coreholes have penetrated aggregate coal thickness of up to 250 feet.

The geology of the PEL 238 area is characterized by buried ridges and troughs and coal gas accumulations considered to be associated with structurally high positions. Coal was deposited throughout the Lower Permian in various parts of the Gunnedah Basin. There are over 500 miles of seismic data available over the PEL 238 area. The coal is dull, blocky and relatively uncleated.

The primary coal objective of the PEL 238 area is Maules Creek at depths of 2,500 to 3,000 feet, and the secondary coal objective is the Hoskisson coal at depths of 1,500 to 2,000 feet. The Maules Creek coal is Permian age coals. In the PEL 238 area, they have a vitrinite reflectance of about 0.7 and are slightly overpressured with a gradient of 0.48 psi per foot. The ashfree gas content of this coal is in the range of 400 to over 500 standard cubic feet per ton of coal. The Maules Creek coal is a closed coal system that is not mined in the area and thus should not be subject to rapid re-charge of the hydro system. The Hoskisson coals have not been tested. All tests to date have been in the Maules Creek area. The Hoskisson coal gas content is in the range of 200 to 300 standard cubic feet per ton of coal. The Hoskisson coal outcrop and is mined to the east of the PEL 238 area.

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The CBM play in the Gunnedah Basin was initiated in 1963 with the Bohena #1 discovery well. The Australian Department of Mines and Resources has drilled over 200 core wells in the eastern portions of PEL 238 and outside the concession area that are useful in delineating the coals.

Activities. In 2003, we were the 100% coalbed methane working interest owner on the approximately 2.0 million acre PEL 238 concession. In 2004, we entered into a joint venture and reduced our CBM ownership to 70%. Over 18 conventional and CBM wells and over 200 coal core holes have previously been drilled within PEL 238. Several PEL 238 CBM wells have demonstrated brief periods of gas production ranging from 200 to 400 Mcfd. However, these wells were not able to sustain these rates, potentially from formation damage caused while drilling. The low sustained gas and water production rates may be due in part, to suboptimal completion techniques. The joint venture is attempting to define the optimum completion technique for the PEL 238 coal that will allow sustained high flow rates to dewater the coal and to support commercially extensive development and tie-ins to surrounding natural gas markets. Additional issues that are being studied include variable carbon dioxide content in the range of 5% to 50% thought to be caused by tertiary volcanics underlying the coal sections in certain areas, correlation of individual coal seams from well to well, variable ash contents, and natural gas marketing issues. Based on these uncertainties, PEL 238 has no proven natural gas reserves.

After taking over the Maules Creek CBM operatorship in 2001, we reworked several CBM wells drilled by the previous operator and established short term production rates that would indicate commercial viability for CBM development. We then equipped the Bohena #3 well with the necessary equipment for a long term production test. Due to extensive well bore damage caused by the previous operator, only a very limited portion of the coals present were able to be reworked. The Bohena #3 well was on continuous production testing from March 2002 to July 2003 and produced at a stabilized rate of approximately 90 Mcfd and 50 Bwd. No other CBM wells were producing in the vicinity of the Bohena #3 well during the timeframe of March 2002 to July 2003 and only very limited de-watering of the coal seams has taken place thus severely limiting gas production. While these test results were not definitive, we continued to believe that development of the CBM resources on the PEL 238 concession could result in substantially higher individual well production.

In the third quarter of 2004, we and our joint venture partners drilled and fracture stimulated two coal seams in two additional vertical CBM wells on PEL 238 to attempt to establish sustained commercial production rates. While we were obligated to drill these wells under a work commitment to New South Wales government to maintain the leases, our joint venture partners have funded the work plan under their earn-in agreement, having increased their ownership interests to 65% during 2005. Management believes that the activities to date have substantially fulfilled the work plan requirements provided in the leases.

Surface facilities were installed and these new vertical CBM wells, and they were placed on production in October 2004. The vertical wells were fracture stimulated using large amounts of sand proppant that was placed in the Upper and Lower Maules Creek coal. The initial and early production flow rates of gas and water indicate that these fracture stimulations were successful. The vertical wells were placed on-line in October 2004 and have produced at very high water rates, indicating good permeability in the coal and an effective stimulation. The wells have also shown early gas production with gas production rising to the anticipated rates for these unconfined wells. The Bohena #9 well initiated production with water rates as high as 400 Bwd and began producing gas after only five weeks of de-watering. After a brief interruption due to the heavy rainfall and flooding, the well has stabilized at approximately 100 Bwd and 70 Mcfd of gas. The Bohena South #1 well began producing in October 2004 at an initial rate of over 1000 Bwd and starting producing gas after only three weeks of de-watering. The Bohena South #1 well is currently producing at rates of approximately 500 Bwd and 60 Mcfd and continues to improve as the fluid level is reduced in the wellbore. The Bibbliwindi #1 well has shown the best performance of the recently drilled wells. That well began producing in October 2004 at approximately 1,000 Bwd and began producing gas immediately. After being shut-in for five months to permit and construct larger water handling facilities, the well was put back on production in June 2005 and is currently producing at a rate of 1,000 Bwd and 17 Mcfd of natural gas.

In addition to these new wells, two older wells were placed back on production. The Bohena #3 and Bohena #7 wells, in the area of the Bohena #9 well, were placed on line in February and March of 2005, respectively. The Bohena #3 well is producing at a rate of 50 Bwd and 100 Mcfd while the Bohena #7 is producing approximately 90 Bwd and 40 Mcfd. The results of all of these wells indicate that commercial gas rates should be achievable with the de-watering of a sufficient area. These conclusions are also supported by reservoir modeling matching the early history of the water and gas production to established reservoir simulations. These simulations indicate peak production rates of approximately 1.5 MMcfd per well.

A lateral CBM well was also drilled and completed in the Bohena coal seam to test the productivity of horizontal well technology on PEL 238 coals. Surface facilities were installed and the horizontal well has produced at high initial water rates and has produced gas; however, the water and gas rates have not been sustainable due to damage done to the coal formation during the drilling of the lateral section of the well. The Maules Creek coal is not cleated and as a result, during drilling operations the coal tends to be ground up and create coal fines that appear to damage native permeability in the coal formation. In the vertical wells, this damage is corrected through the fracture stimulations.

If the production performance of these wells continues to confirm the positive results seen recently and in earlier PEL 238 wells, we hope to develop an area sufficient to justify the installation of gathering and transportation assets to serve several local natural gas markets. In order to construct a pipeline for the Bohena area to a local power plant pipeline, it is necessary to file a Development Application, or DA, with the Narrabri Shrine Council, or NSC, and a registration of an easement along the pipeline route. As part of the DA, a Statement of Environmental Effects, or SOEE, will also need to be filed with the NSC. We and our joint venture partners plan to file the DA and SOEE by the end of September 2005. Development consent is anticipated to be granted before the end of 2005.

PEL 238, which includes substantial forest lands, was a part of a New South Wales government-sponsored bioregion study evaluating various land use options for the forests. While there was a wide range of possible land use options proposed, some of which could restrict our access to portions of PEL 238, the final designation of the land within the Bohena project area, covering the planned CBM development area, as Community Conservation Area Zone 4 (forestry, recreation and mineral extraction) should have no material impact on the project. Management and our joint venture partners actively participated in the bioregion process to ensure that our position was well represented and to ensure that our leasehold interests continue to be available for exploration and production.

We and our joint venture partners had committed to spend approximately $1.4 million during the permit year that ended August 2, 2005. The joint venture has spent approximately $2.3 million during the period. The joint venture is currently seeking approval from the New South Wales government, proposing to spend an additional $1.4 million in each of the two work program years ending August 2, 2006 and 2007. The proposed work program calls for the drilling of two CBM well in each of the two years, together with continued geological and geophysical activities and ongoing production management. We will bear 35% of these expenditures. PEL 238 will be due for renewal in August 2007. Although there is no assurance that the PEL 238 license will be renewed in 2007, the New South Wales government has typically ruled to extend such licenses.

Gippsland Basin, Victoria, Australia

General. The Gippsland property is located in the onshore portion of Gippsland Basin in Victoria, Australia. The Gippsland Basin is a proven hydrocarbon province that has produced substantial volumes of oil, natural gas and coal. Our project area covers almost all of the onshore part of the Gippsland Basin. The coal in the Gippsland Basin is primarily brown and subbituminous coals, which is similar in composition and age to the coal in the Powder River Basin of Wyoming and Montana. As in the Powder River Basin, very large open pit coal mines are operated in the Gippsland Basin. The mines are located on a relatively small part of the basin near our acreage. Substantial information on the physical properties of the Gippsland Basin coal has been developed due to the extensive mining operations.

Although there has been no organized attempt to date to produce CBM from the Gippsland coal, the stratigraphy and structure of the coal is well known due to extensive core bores, water bores, coal mining operations, petroleum exploration, and other geotechnical evaluations of the coal. While no data on coal gas content and permeability is currently available, natural gas has been measured in the coal and observed coming to the surface during conventional natural gas and oil exploration. The basin has multiple coal sequences at depths of less than 3,000 feet with total coal thicknesses as great as 1,000 feet and with individual seams over several hundred feet thick, which are believed to be some of the thickest brown coal seams in the world. We hope to use CBM techniques developed in the Powder River Basin and other CBM fields to evaluate Gippsland Basin CBM potential.

Activities. We have an interest in mineral licenses that encompass approximately 1.4 million gross (1.1 million net) acres of Onshore Gippsland Basin in Victoria Australia. We own a 75% working interest in the Gippsland CBM rights and mineral sands rights with Geostar owning the remaining 25% working interest in the CBM and mineral sands rights.

No Gippsland Basin CBM production has been established to date; however, we have recently completed the drilling of two dedicated CBM wells on a site near several conventional wells that penetrated the targeted coal and encountered evidence of both permeability in the coal formation (lost drilling fluids) and the presence of CBM (gas circulated from mud systems after losing drilling fluids to the coal). Both of these new dedicated CBM wells have been drilled using drilling and completion techniques commonly used in the Powder River Basin. Each well was drilled to the top of the coal section and casing was cemented into place. Following the installation of the casing, the wells were then drilled through the coal and, if necessary, the coal are under reamed to create a large diameter cavity in the coal section. We are currently awaiting the availability of service companies to conduct water enhancements of the coal zones, a commonly used stimulation technique in the Powder River Basin that flushes the coal fines created during drilling away from the wellbore in order to create better permeability for the CBM gas to migrate to the wellbore. Upon the completion of the water enhancements, we plan to place the wells on production and begin testing the water and gas production rates in order to estimate recoverable reserves per well.

If the pilot program is successful, access to gas markets is available through three major pipelines that cross our Gippsland properties; one northeast to Sydney, one south to Tasmania, and one west to Melbourne. Additional potential gas markets for Gippsland Basin CBM production include mining projects located near our mineral licenses that potentially could use large amounts of natural gas in value-adding heating and roasting processes. Gas marketing agreements would need to be negotiated with potential customers.

We and our partner were obligated to spend approximately $1.5 million on a work program by April 2004 to maintain our Gippsland Basin leases. Although we did not meet our spending commitment, due in large part to regulatory delays encountered in obtaining certain permits, we met with the Government of Victoria in 2004 and our leases were extended until April 2006.

In the fourth quarter of 2004, in accordance with common government leasing practices, we relinquished approximately 382,000 gross acres to the Government of Victoria. During the first and second quarters of 2005, we drilled the first two dedicated CBM test wells on our EL 4416 license in the Gippsland Basin, located in Victoria, Australia. We hold a 75% working interest in the CBM and Mineral Sands rights on the 1.4 million gross acre concession with the balance owned and operated by a subsidiary of Geostar. The wells are anticipated to be completed during the third quarter utilizing open-hole completion techniques commonly used in the Powder River Basin area.

While coalbed methane has been the primary focus of our efforts on the Gippsland property, our exploration license is not limited to CBM only. The Gippsland exploration licenses also include mineral rights on the properties. Our partner and we are conducting an advanced technical assessment of the mineral potential of these properties. While the assessment of the various minerals potential is in its early stages, the initial focus is on mineral sands, a major natural resource in other basins within Victoria. We have designed a mineral sands

ground magnetic exploration program to further evaluate mineral sands potential. The coring portion of this program was recently completed and the data acquired is currently being evaluated.

Our exploration license requires that our net cumulative expenditure to date be approximately $1.5 million. Actual capital expenditures to date have totaled approximately $2.0 million, with an approximate $375,000 remaining to be spent over the balance of the term of the license. The license will expire April 2006, unless it is extended by the Government of Victoria. We anticipate that the Government of Victoria will require us to surrender approximately 35% of our current acreage upon license renewal for an additional five years.

Cherokee Basin, Kansas

We were a party to a purchase and sale contract to develop, as project operator, approximately 110,000 acre CBM property in the Cherokee Basin of Kansas. We conducted extensive geological, engineering, and economic evaluation of the property. The property was subsequently sold for $500,000. In addition to funds received in the divestment, we retained a small overriding royalty. The purchaser has been reported to have drilled numerous CBM wells, of which we have received overriding royalty interest assignments on approximately 116 wells.

Natural Gas and Oil Reserves

Our estimated total net proved reserves of natural gas and oil as of December 31, 2004, 2003 and 2002, and the present values of estimated future net revenues attributable to those reserves as of those dates, are presented in the following table. For the definition of proved reserves, see Glossary of Natural Gas and Oil Terms . These estimates were prepared by Netherland, Sewell & Associates, Inc., independent reservoir engineers, and are part of their reserve reports on our natural gas and oil properties. Netherland, Sewell & Associates 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, Netherland, Sewell & Associates 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.

	As of December 31,		
	2004	**2003**	**2002**
Estimated Net Proved Reserves:			
Net natural gas reserves (MMcf):			
Proved developed	6,179	1,865	4,650
Proved undeveloped	15,221	5,999	10,526
Total	21,400	7,864	15,176
Net oil reserves (MBbl):			
Proved developed	6	4	26
Proved undeveloped			
Total	6	4	26
Total proved natural gas and oil reserves (MMcfe)	21,436	7,887	15,330

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. Our estimated proved reserves have not been filed with or included in reports to any U.S. federal agency.

Pricing Assumptions

SEC regulations require that the gas and oil prices used in Netherland, Sewell & Associates reserve reports are the period-end prices for gas and oil at December 31, 2004, 2003 and 2002, respectively. These prices are projected without inflation for the life of the wells included in the reserve reports. The pricing assumptions are listed below:

	2004 Report Gas ($/MMBtu)	2003 Report Gas ($/MMBtu)	2002 Report Gas ($/MMBtu)
Powder River Basin (Wyoming and Montana)	$ 5.52	$ 5.58	$ 3.12
Hilltop Area (East Texas)	$ 5.82	$ 5.97	$ 4.74
Appalachian Basin (West Virginia)	$ 6.45	$ 5.71	$ 4.80
Cherokee Basin (Kansas)	$ 6.18	$ 5.97	$ 4.74
	Oil ($/Bbl)	**Oil ($/Bbl)**	**Oil ($/Bbl)**
Appalachian Basin (West Virginia)	$ 39.75	$ 29.25	$ 27.50

Drilling Activities

The following indicates the number of natural gas and oil wells drilled during the periods indicated. As used below, undecided wells are wells for which permanent equipment was installed for the production of natural gas or oil but that as of each respective period end were in the process of de-watering.

	Number of Natural Gas Wells							
	Productive		Dry		Undecided		Total Wells	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Nine Months Ended September 30, 2005								
Exploratory	1	0.7			5	3.5	6	4.2
Development	66	17.0			14	3.2	80	20.2
Year Ended December 31, 2004								
Exploratory	2	1.3			3	1.5	5	2.8
Development	113	25.7			5	1.1	118	26.8
Year Ended December 31, 2003								
Exploratory	1	0.8					1	0.8
Development	133	24.6			6	1.0	139	25.6
Year Ended December 31, 2002								
Exploratory					1	0.1	1	0.1
Development	23	12.0					23	12.0

Acreage and Productive Wells

The following table sets forth our ownership interest in undeveloped acreage, developed acreage and productive wells in the areas indicated where we own a working interest as of September 30, 2005. Gross represents the total number of acres or wells in which we own a working interest. Net represents our proportionate working interest resulting from our ownership in gross acres or wells. Productive wells are wells in which we have a working interest and that are capable of producing natural gas or oil. Wells that are completed in more than one producing horizon are counted as one well.

	Undeveloped Acres		Developed Acres		Productive Wells	
Region	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Powder River Basin, Wy.	33,917	11,992	21,880	9,633	299	134.5
Appalachia, W.Va.	25,466	12,532	1,187	735	8	5.9
California	3,040	3,040				
Texas	49,100	31,603	2,723	2,433	4	3.9
Total United States	111,523	59,167	25,790	12,801	311	144.3
PEL 238	1,997,800	699,230	2,200	770		
Gippsland Basin	1,400,000	1,050,000				
Total Australia	3,397,800	1,749,230	2,200	770		

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The following table sets forth as of September 30, 2005, the expiration periods of the gross and net undeveloped acreage:

	Undeveloped Acres			
	United States		Australia	
	Gross	Net	Gross	Net
Three Months Ended:				
December 31, 2005	1,221	827		
Twelve Months Ended:				
December 31, 2006	29,759	12,023	1,400,000	1,050,000
December 31, 2007	32,466	18,467	1,997,800	699,230
December 31, 2008	20,757	13,129		
December 31, 2009	6,831	3,416		
December 31, 2010 and later	284	284		

Volumes, Prices and Production Costs

The following table sets forth information with respect to our production volumes, average prices received and average production costs for the periods indicated:

	For the Nine Months Ended September 30,		For the Years Ended December 31,		
	2005	2004	2004	2003	2002
Production:					
Natural gas (MMcf)	2,614.8	353.0	1,108.0	385.0	393.2
Oil (MBbl)	1.6	1.1	1.8	1.0	3.1
Oil Natural gas equivalents (Mmcfed)	2,624.3	359.4	1,118.8	391.0	411.6
Natural gas (MMcfd)	9.6	1.3	3.0	1.1	1.1
Oil (MBod)	0.0	0.0	0.0	0.0	0.0
Oil Natural gas equivalents (Mmcfe)	9.6	1.3	3.1	1.1	1.1
Average Sales Prices:					
Natural gas ($ per Mcf)	$ 6.67	$ 4.67	$ 5.40	$ 3.72	$ 1.33
Oil ($ per Bbl)	$ 50.19	$ 37.75	$ 40.08	$ 27.89	$ 20.15
Lease, transportation and selling ($ per Mcfe)	$ 1.53	$ 2.61	$ 1.78	$ 1.82	$ 1.75

Markets and Customers

The success of our operations is dependent upon prevailing prices for natural gas and oil. The markets for natural gas and oil have historically been volatile and may continue to be volatile in the future. Natural gas and oil prices are beyond our control. However, rising demand for natural gas to fuel power generation and meet increasing environmental requirements has led some industry observers to indicate that long term demand for natural gas is increasing.

Our current United States production has access to major intrastate and interstate pipeline systems. We contract to sell gas from our properties with spot-market based contracts that vary with market forces on a monthly basis. While overall gas prices at major markets, such as Henry Hub in Louisiana, may have some impact on regional prices, the regional natural gas price at our production facilities may move somewhat independently of broad industry price trends. Because some of our operations are located in specific regions, we are directly impacted by regional natural gas prices in those regions regardless of pricing at major market hubs.

The East Texas Basin area has an extensive natural gas pipeline infrastructure in place. Our Deep Bossier production is transported to the Katy Hub in Katy, Texas, where numerous parties are available to purchase our

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natural gas production. Powder River Basin natural gas is sold under spot market contracts to major pipeline and natural gas marketing companies. These companies purchase essentially all of our current production.

The initial gas market for PEL 238 natural gas is anticipated to be a natural-gas fired electricity generation facility owned and operated by one of our joint venture partners and located near the town of Narrabri, New South Wales, Australia. Although there currently is no existing pipeline from the existing and planned CBM project areas, we and our joint venture partners are finalizing plans for a gathering system and pipeline to transport the CBM gas that we produce to the electricity generation facility. The longer term gas market for PEL 238 natural gas is considered to be future gas-fired power generation facilities in New South Wales and the industrial and residential markets in the Sydney and Newcastle areas of New South Wales. While there are currently no pipelines connecting our project areas within PEL 238 to the Sydney and Newcastle gas markets, a new 180 mile pipeline that will terminate within approximately 75 miles of our PEL 238 project areas has been announced and is expected to be begin construction in August 2005 and be operational by the second quarter of 2006.

Australian gas markets and natural gas infrastructure exist and are viable markets; however, they are not as developed as the markets and infrastructure in the United States. Specifically, the PEL 238 concession is currently not served by natural gas infrastructure. Gastar and its joint venture partners have recently entered into discussions with a third party entity that is constructing an approximate 190-mile pipeline in the vicinity of the PEL 238 concession. This pipeline would provide access to local markets in New South Wales and eventually to larger gas markets in the Sydney and Newcastle areas. These discussions involve negotiations outlining preliminary terms under which the third party would extend the pipeline currently under construction to the area of PEL 238, which is currently scheduled for further evaluation. Gastar expects that these discussions will lead to a formal agreement prior to the time that the planned development wells will be ready to enter production.

The EL 4416 license in the Gippsland Basin of Victoria, the site of recent pilot CBM drilling and planned production testing, is served by three existing natural gas transmission pipelines. The existing pipelines have capacity to transport natural gas from the EL 4416 license to markets in the area of Sydney, Melbourne and Tasmania. If Gastar s efforts result in commercial CBM production from this license, minimal infrastructure expenditures would be necessary to connect to the existing pipelines.

Our very limited oil production in West Virginia is sold under spot sales transactions at market prices. The availability and price responsiveness of the multiple oil purchasers provides for a highly competitive and liquid market for oil sales.

We have not pre-sold any natural gas or oil and have no future volume delivery commitments of any kind.

During 2004, ETC Texas Pipeline Ltd. and Western Gas Resources, Inc. accounted for 59% and 10%, respectively, of the Company s oil and natural gas revenues. During 2003, Western Gas Resources, Inc. and Equitable Gas Company, a division of Equitable Resources, Inc. accounted for 72% and 17%, respectively, of the Company s oil and natural gas revenues. Management believes that the loss of any individual purchaser would not have a long-term material adverse impact on the financial position or results of operations of the Company.

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

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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 and oil 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.

Governmental Regulation

In addition to the environmental regulations discussed below under the heading Environmental Regulation , our natural gas and oil exploration, production and related operations are subject to extensive rules and regulations promulgated by federal, state and local governmental agencies. These laws and regulations, all of which are subject to change from time to time, include matters relating to land tenure; drilling and production practices such as discharge permits and the spacing of wells; the disposal of water resulting from operations and the processing, handling and disposal of hazardous materials such as hydrocarbons and naturally occurring radioactive materials; bonding requirements; reporting requirements; marketing and pricing policies; royalties; taxation; and foreign trade and investment.

Failure to comply with these rules and regulations can result in substantial penalties. Furthermore, we could be liable for personal injuries, property damage, spills, discharge of hazardous materials, reclamation costs, remediation, clean-up costs and other environmental damages as a consequence of acquiring a natural gas or oil opportunity.

The regulatory burden on the natural gas and oil industry increases our cost of doing business and affects our financial condition. Although we believe we are in substantial compliance with all applicable laws and regulations, we are unable to predict the future cost or impact of complying with such laws because those laws and regulations are frequently amended or reinterpreted. We are unable to predict what additional legislation or amendments may be proposed that will affect our operations or when any such proposals, if enacted, might become effective.

U.S. Regulation

Transportation and Sale of Natural Gas. Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and the regulations promulgated thereunder by the Federal Energy Regulatory Commission (FERC). In the past, the federal government has regulated the prices at which natural gas could be sold. Deregulation of natural gas sales by producers began with the enactment of the Natural Gas Policy Act of 1978. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining Natural Gas Act of 1938 and Natural Gas Policy Act of 1978 price and non-price controls affecting producer sales of natural gas effective January 1, 1993. Congress could, however, re-enact price controls in the future.

FERC regulates interstate natural gas pipeline transportation rates and service conditions, which affect the marketing of gas produced by us and the revenues received by us for sales of such natural gas. The FERC requires interstate pipelines to provide open-access transportation on a non-discriminatory basis for all natural gas shippers. The FERC frequently reviews and modifies its regulations regarding the transportation of natural gas with the stated goal of fostering competition within all phases of the natural gas industry. In addition, with respect to production onshore or in state waters, the intra-state transportation of natural gas would be subject to state regulatory jurisdiction as well.

Additional proposals and proceedings that might affect the natural gas industry are considered from time to time by Congress, the FERC, state regulatory bodies and the courts. We cannot predict when or if any such proposals might become effective or their effect, if any, on our operations. The natural gas industry historically has been closely regulated; thus, there is no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue indefinitely into the future. We do not believe that we will be affected by any action taken in a materially different way than other natural gas producers, gatherers and marketers with which we compete.

Federal Regulation of Sales and Transportation of Crude Oil. Our sales of crude oil and condensate are not currently regulated and are made at market prices. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act. Certain regulations implemented by the FERC in recent years could result in an increase in the cost of pipeline transportation service. We do not believe, however, that these regulations affect us any differently than other producers.

Our operations are subject to extensive and continually changing regulation affecting the oil and natural gas industry. Many departments and agencies, both federal and state, are authorized by statute to issue, and have issued, rules and regulations binding on the oil and natural gas industry and its individual participants. The failure to comply with such rules and regulations can result in substantial penalties. The regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability. We do not believe that we are affected in a significantly different manner by these regulations than are our competitors.

Regulation of Production. The production of oil and natural gas is subject to regulation under a wide range of state and federal statutes, rules, orders and regulations. State and federal statutes and regulations require permits for drilling operations, drilling bonds, and reports concerning operations. Most states in which we own and operate properties, have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and natural gas wells, the spacing of wells, and the plugging and abandonment of wells and removal of related production equipment. Many states also restrict production to the market demand for oil and natural gas and several states have indicated interests in revising applicable regulations. These regulations can limit the amount of oil and natural gas we can produce from our wells, limit the number of wells, or limit the locations at which we can conduct drilling operations. Moreover, each state generally imposes a production or severance tax with respect to production and sale of natural gas, natural gas liquids and crude oil within its jurisdiction.

Australian Regulation

Commonwealth of Australia Laws and Regulations. The regulation of the natural gas and oil industry in Australia is similar to that of the United States, in that regulatory controls are imposed at both the state and commonwealth (federal) levels. Specific commonwealth regulations impose environmental, cultural heritage and native title restrictions on accessing resources in Australia. These regulations are in addition to any state level regulations. Foreign investment in Australia is regulated by the commonwealth through its foreign investment legislation and policy. In some circumstances, Australian foreign investment regulation and policy requires foreign interests to obtain prior approval from the Australian Government before investing in specific industry sectors. The Foreign Investment Review Board administers the regulation of foreign investment on behalf of the commonwealth. Its functions include analyzing proposals by foreign interests for investment in Australia and making recommendations to the Government on the compatibility of those proposals with Government policy and the relevant legislation. In some circumstances the acquisition of or formation of a new business will require review and approval under the commonwealth foreign investment policy and regulations. 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

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lost. Native title legislation was enacted in 1993 in order to provide a statutory framework for deciding questions such as where native title exists, who holds native title and the nature of native title which were left unanswered by a 1992 Australian High Court decision. Native title claims by aboriginal groups can include claims over existing and potential natural gas and oil exploration and development areas. The commonwealth government has passed amendments to this legislation to clarify uncertainty in relation to the evolving native title legal regime in Australia created by the decision in another High Court case decided in 1996. Since 1998 the native title legislation has provided for interested parties to negotiate and register indigenous land use agreements with registered native title claimants in the early stages of development. Our Australian operations could be affected by native title claims by Aboriginal groups. Each authority to prospect, lease and pipeline license must be examined individually in order to determine validity and native title claim vulnerability.

Australia Gas Markets. Several statutory mechanisms regulate access rights to a range of infrastructure in Australia including gas transmission pipelines. These involve generic access regulations contained in the *Trade Practices Act 1974 Cth.* and industry specific schemes contained in specific legislative instruments, industry codes and schemes. Objectives of this regulatory regime include providing a process for establishing third party access to natural gas pipelines, facilitating the development and operation of a national natural gas market, promoting a competitive market for natural gas in which customers are able to choose their supplier, and providing a right of access to transmission and distribution networks on fair and reasonable terms and conditions. We cannot currently ascertain the impact of the regime objectives but believe it should benefit us.

Environmental Regulation

Our natural gas and oil exploration and production operations and similar operations that we do not operate but in which we own a working interest in the United States are subject to significant federal, state and local environmental laws and regulations governing environmental protection as well as the discharge of substances into the environment. These laws and regulations may restrict the types, quantities and concentrations of various substances that can be released into the environment as a result of natural gas and oil drilling, production and processing activities; suspend, limit or prohibit construction, drilling and other activities in certain lands lying within wilderness, wetlands and other protected areas; require remedial measures to mitigate pollution from historical and on-going operations such as the use of pits and plugging of abandoned wells; and restrict injection of liquids into subsurface strata that may contaminate groundwater. Governmental authorities have the power to enforce compliance with their laws, regulations and permits, and violations are subject to injunction, as well as administrative, civil and even criminal penalties. The effects of these laws and regulations, as well as other laws or regulations that are adopted in the future, could have a material adverse impact on our operations and other operations in which we own an interest. As discussed below, our Australian operations are similarly subject to regulation by Australian authorities.

We believe that we are in substantial compliance with existing applicable environmental laws and regulations. However, it is possible that new environmental laws or regulations or the modification of existing laws or regulations could have a material adverse effect on our operations and other operations in which we own an interest. As a general matter, the recent trend in environmental legislation and regulation is toward stricter standards, and this trend will likely continue. To date, we have not been required to expend extraordinary resources in order to satisfy existing applicable environmental laws and regulations. However, costs to comply with existing and any new environmental laws and regulations could become material. In addition, if substantial liabilities to third parties or governmental entities are incurred, the payment of such claims may reduce or eliminate the funds available for project investment or result in loss of our properties. Moreover, a serious incident of pollution may result in the suspension or cessation of operations in the affected area. Although we maintain insurance coverage against costs of clean-up operations, no assurance can be given that we are fully insured against all such potential risks. The imposition of any of these liabilities or compliance obligations on us may have a material adverse effect on our financial condition and results of operations.

The following is a summary of some of the existing environmental laws, rules and regulations to which our business operations are subject.

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U.S. Environmental Laws

In the United States, environmental laws are implemented principally by the United States Environmental Protection Agency, or EPA, the Department of Transportation and the Department of the Interior, as well as other comparable state agencies.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, also known as the Superfund law, imposes strict, joint and several liability without regard to fault or legality of conduct, on persons who are considered to have contributed to the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substance released at the site. Under CERCLA, such persons may be liable for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring land owners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. Although CERCLA currently excludes petroleum and natural gas, natural gas liquids, liquefied natural gas or synthetic gas useable for fuel, from the definition of hazardous substance, our operations as well as other operations in which we own an interest may generate materials that are subject to regulation as hazardous substances under CERCLA.

CERCLA may require payment for cleanup of certain abandoned waste disposal sites, even if such waste disposal activities were undertaken in compliance with regulations applicable at the time of disposal. Under CERCLA, one party may, under certain circumstances, be required to bear more than its proportional share of cleanup costs if payment cannot be obtained from other responsible parties. CERCLA authorizes the EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. The scope of financial liability under these laws involves inherent uncertainties.

Resource Conservation and Recovery Act. The Resource Conservation and Recovery Act, or RCRA, and comparable state programs regulate the management, treatment, storage and disposal of hazardous and non-hazardous solid wastes. Our operations and other operations in which we own an interest generate wastes, including hazardous wastes, that are subject to RCRA and comparable state laws. We believe that these operations are currently complying in all material respects with applicable RCRA requirements. Although RCRA currently exempts certain natural gas and oil exploration and production wastes from the definition of hazardous waste, we cannot assure you that this exemption will be preserved in the future, which could have a significant impact on us as well as of the oil and gas industry, in general.

We currently own, lease, own a working interest in, or operate numerous properties that for many years have been used by third parties for the exploration and production of natural gas and oil. Although we abide by standard industry operating and disposal practices, hazardous substances, wastes, or hydrocarbons may have been released on or under the properties owned or leased by us or in which we own an interest, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, many of these properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons was not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes (including substances disposed of or released by prior owners or operators), remediate contaminated property, or perform remedial plugging or pit closure operations to prevent future contamination.

Water Discharges. Our operations and other operations in which we own a working interest are subject to the Clean Water Act, or CWA, as well as the Oil Pollution Act, or OPA, and analogous state laws and regulations. These laws and regulations impose detailed requirements and strict controls regarding the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States, including

wetlands. Under the CWA and OPA, any unpermitted release of pollutants from operations could cause us to become subject to: the costs of remediating a release; administrative, civil or criminal fines or penalties; or OPA specified damages, such as damages for loss of use and natural resource damages. In addition, in the event that spills or releases of produced water from natural gas and oil production operations were to occur, we would be subject to spill notification and response requirements under the CWA or the equivalent state regulatory program. Depending on the nature and location of these operations, spill response plans may also have to be prepared.

Our natural gas and oil exploration and production operations and other operations in which we own an interest generate produced water as a waste material, which is subject to the disposal requirements of the CWA, Safe Drinking Water Act, or SDWA, or an equivalent state regulatory program. Naturally occurring groundwater is also typically produced by CBM production in our operations or in other operations in which we own an interest. This produced water is disposed of by re-injection into the subsurface through disposal wells, discharge to the surface, or in evaporation ponds. Whichever disposal method is used, produced water must be disposed of in compliance with permits issued by regulatory agencies, and in compliance with applicable environmental regulations. This water can sometimes be disposed of by discharging it under discharge permits issued pursuant to the CWA or an equivalent state program. Another common method of produced water disposal is subsurface injection in disposal wells. Such disposal wells are permitted under the SDWA, or an equivalent state regulatory program. To date, we believe that all necessary surface discharge or disposal well permits have been obtained and that the produced water has been discharged into the produced water disposal wells in substantial compliance with such obtained permits and applicable laws.

Air Emissions. The Clean Air Act, or CAA, and comparable state laws and regulations govern emissions of various air pollutants through the issuance of permits and the imposition of other requirements. Air emissions from some equipment found at our operations or other operations in which we own an interest, such as gas compressors, are potentially subject to regulations under the Clean Air Act or equivalent state and local regulatory programs, although many small air emission sources are expressly exempt from such regulations. To the extent that these air emissions are regulated, they are generally regulated by permits issued by state regulatory agencies. To date, we believe that no unusual difficulties have been encountered in obtaining air permits. However, in the future, we may be required to incur capital expenditures in connection with maintaining or obtaining operating permits and approvals addressing air emission-related issues.

CBM production operations involve the use of gas-fired compressors to transport gas that is produced. Emissions of combustible by-products from compressors at one location may be great enough to subject the compressors to CAA and comparable state air quality regulation requirements for pre-construction and operating permits. To date, we believe that such gas-fired compressors operated by us or at other operations in which we own a working interest have been operated in substantial compliance with obtained permits and the applicable federal, state and local laws and regulations without undue cost to or burden on our business activities. Another air emission associated with these CBM operations that may be subject to regulation and permitting requirements is particulate matter resulting from construction activities and vehicle traffic. To date, we do not believe there has been any unusual difficulty in complying with requirements related to particulate matter.

Other Laws and Regulations. Our operations and other operations in which we own a working interest are also impacted by regulations governing the handling, transportation, storage and disposal of naturally occurring radioactive materials. Furthermore, owners, lessees and operators of natural gas and oil properties are also subject to increasing civil liability brought by surface owners and adjoining property owners. Such claims are predicated on the damage to or contamination of land resources occasioned by drilling and production operations and the products derived therefrom, and are often based on negligence, trespass, nuisance, strict liability or fraud.

In addition, our operations and other operations in which we own an interest may in the future be subject to the regulation of greenhouse gas emissions. In 1997, numerous countries reached agreement on the Kyoto Protocol to the United Nations Framework Convention on Climate Change. If the Protocol enters into force, adopting countries would be required to implement national programs to reduce emissions of certain gases, generally referred to as greenhouse gases, that are suspected of contributed to global warming. The Bush

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Administration has indicated it will not support ratification of the Protocol, and Congress has resisted recent proposed legislation directed at reducing greenhouse gas emissions. However, there has been support in various regions of the country for legislation that requires reductions in greenhouse gas emissions, and some states have already adopted legislation addressing greenhouse gas emissions from certain greenhouse gas emission sources, primarily power plants. The oil and gas exploration and production industry is a direct source of certain greenhouse gas emissions, namely carbon dioxide and methane, and future restrictions on such emissions could impact our future operations. Our operations and other operations in which we own an interest currently are not adversely impacted by current state and local climate change initiatives; however, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business.

Finally, legislation continues to be introduced in Congress and development of regulations continues in the Department of Homeland Security and other agencies concerning the security of industrial facilities, including oil and gas facilities. Our operations and the operations of the oil and gas industry in general may be subject to such laws and regulations. Presently, it is not possible to accurately estimate the costs we could incur to comply with any such facility security laws or regulations, but such expenditures could be substantial.

Australian Environmental Laws

Australia has environmental laws and regulations that are similar in scope and impact to United States environmental laws and regulations. Similar approval, licensing and operational impacts apply at a commonwealth, state and local government level. As a result, environmental laws and regulations can result in similar licensing and operational impacts in Australia that are similar to those discussed above with respect to the United States.

The legislation regulating environmental assessment at a commonwealth level is the *Environmental Protection and Biodiversity Conservation Act 1999 (Cth.)*. This Commonwealth Act establishes a regime for protecting the environment, flora and fauna biodiversity and Australian national heritage. It requires any person taking an action which could have a significant impact on one of these values to refer it to the commonwealth Minister for the Environment for consideration and potential assessment. The Act only applies to matters of national environmental or heritage significance. These are matters which impact on a world heritage site, Ramsar wetlands, species which are listed as threatened under the Act, migratory species, nuclear actions and commonwealth marine areas or places listed on the commonwealth heritage list. Operators are required to assess their projects to determine whether an action is likely to have a significant impact on matters of national environmental significance, and make a decision respecting submission of that assessment to a public referral process. The referral is expected to add some time to the existing approval process but have little impact on most routine activities and operations. In addition, see the discussion in Business Gunnedah Basin, New South Wales, Australia for a discussion of the New South Wales government s bioregion study involving PEL 238. Environmental protection is also regulated in each state and territory by specific legislation enacted by each state or territory. The governments of New South Wales and Victoria both have a suite of legislation regulating environmental matters in their states. The legislation imposes a licensing approval and contamination management scheme which may impact on our operations and impose a liability which may extend beyond the time period during which properties are operated, occupied or owned. The laws and regulations also restrict emissions to air, land and water and may control or regulate substances which can be released into the environment and the manner in which they are transported and disposed of. Environmental laws and regulations protecting archeological relics, natural and built heritage as well as native flora and fauna can also impact on our operations and impose obligations in respect of restitution or replacements well as liability in respect of damage.

Australia Gas Markets. Several statutory mechanisms regulate access rights to a range of infrastructure in Australia including gas transmission pipelines. These involve generic access regulations contained in the *Trade Practices Act 1974 Cth.* and industry specific schemes contained in specific legislative instruments, industry codes and schemes. Among the objectives of this regulatory regime are: to provide a process for establishing third party access to natural gas pipelines, to facilitate the development and operation of a national natural gas market, to promote a competitive market for natural gas in which customers are able to choose their supplier, and to provide a right of access to transmission and distribution networks on fair and reasonable terms and conditions. We cannot currently ascertain the impact of the regime objectives but believe it should benefit us.

Legal Proceedings

First Sourcenergy Group, Inc., one of our wholly owned subsidiaries, is a named party to an arbitration proceeding captioned Estate of Virgil Sparks and Oil Wells of Kentucky, Inc. v First Sourcenergy Group, Inc. and Geostar. The dispute involves historical dealings with the development of an Authority to Prospect (ATP) Area in Queensland, Australia, as well as an ancillary agreement. The formal arbitration is in discovery stages. First Sourcenergy Group, Inc. and Geostar have moved to dismiss the Arbitration on the grounds of a claimed prior settlement and release agreement. First Sourcenergy Group, Inc. and Geostar are vigorously defending the arbitration, and firmly believe that its position is sound. Further, an interest in ATP 560 was transferred from First Sourcenergy Group, Inc. to Conquest Exploration, Inc. in 2001, the result of which means that, although First Sourcenergy Group, Inc. is a named defendant, Conquest Exploration, Inc. and Geostar would bear primary liability from this arbitration action.

On May 3, 2005 Western Gas Resources, Lance Oil and Gas Company, Inc. and Williams Production RMT Company filed a lawsuit against us and others over a dispute that has arisen concerning a June 2002 Lease Exchange and Purchase Agreement between certain of the parties. The issue involves a certain gas gathering agreement and its applicability to some of the properties exchanged under the June 2002 Agreement. A formal response to the complaint was filed in June 2005. We believe that we have multiple strong defenses to this action and intend to vigorously advance our positions. We do not anticipate that this action will result in a material loss.

In connection with the Chesapeake transaction, we notified Chesapeake of a recent claim made by a third party that it has a right to purchase 33.33% of our interests in certain oil and gas leases located in Leon and Robertson Counties, Texas pursuant to a preferential right provision of an operating agreement dated July 7, 2000. On October 31, 2005, the third party filed a related petition for breach of contract and declaratory judgment in a legal action, as Navasota Resources, L.P. vs. First Source Texas, Inc., First Source Gas L.P., and Gastar Exploration Ltd. (Cause No. 0-05-451), in the District Court of Leon County, Texas, 12th Judicial District. We contend, among other things, that the claimant neither properly nor timely exercised any preferential right election it may have had with respect to the inter-dependent transactions. Accordingly, we intend to vigorously defend the claims.

We are subject to various regulatory and statutory requirements relating to the protection of the environment. These requirements, in addition to contractual agreements and management decisions, result in the accrual of estimated future removal and site restoration costs. These costs are initially measured at a fair value and are recognized in the consolidated financial statements as the resent value of expected future cash flows. Subsequent to the initial measurement, the effect of the passage of time on the liability for the ARO (accretion expense) and the amortization of the ARO cost are recognized in the results of operations. Costs attributable to these commitments and contingencies are expected to be incurred over an extended period of time and are to be funded mainly from our cash provided by operating activities. Although the ultimate impact of these matters on net earnings cannot be determined at this time, it could be material for any one quarter or year.

In addition, we are involved in various other claims and legal actions arising out of the normal course of our business. We do not expect that the outcome of these proceedings will have a material adverse effect on our financial position, results of operations or cash flow.

Employees

Currently, we have 11 employees, all of whom are full time. 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.

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MANAGEMENT

Directors, Officers and Certain Named Individuals

Our directors, executive officers and certain named individuals and their ages as of September 30, 2005 are as follows:

Name	Age	Position
Thomas E. Robinson	50	Chairman of the Board of Directors
J. Russell Porter	43	Chief Executive Officer, President, Chief Operating Officer and Director
Michael A. Gerlich	51	Chief Financial Officer & Vice President
Frederick J. Lambert	35	Controller
Sara-Lane Sirey	37	Corporate Secretary
Abby Badwi	59	Director
Thomas Crow	74	Director
Matthew J. P. Heysel	49	Director
Richard Kapuscinski	43	Director

Thomas E. Robinson has been a member and the Chairman of our Board of Directors since February 2001. Mr. Robinson has more than 20 years of experience investing in various areas in the natural gas and oil industry, both as an investor in and developer of exploration projects. During this period, he directed natural gas and oil drilling and production activities for Geostar and individually in the United States (including the states of Michigan, Illinois, Texas, Kansas, Kentucky and Wyoming) and New South Wales, Victoria and the Cooper Basin in Australia. Mr. Robinson is the Chief Executive Officer of Geostar, a position he has held since January 1994. From May 2000 to February 2004, Mr. Robinson also served as our President and Chief Executive Officer.

J. Russell Porter has been a member of our Board of Directors and has served as our Chief Executive Officer and President since February 2004. From September 2000 to February 2004, he served as our Chief Operating Officer. Mr. Porter has a unique background, with approximately 14 years of natural gas and oil exploration and production experience and five years of banking and investment experience specializing in the natural gas and oil industry. From April 1994 to September 2000, Mr. Porter served as an Executive Vice President of Forcenergy, Inc., a publicly traded exploration and production company, where he was responsible for the acquisition and financing of the majority of its assets across the United States and Australia. Mr. Porter holds a BS degree in Petroleum Land Management from Louisiana State University and a MBA from the Kenan-Flagler School of Business at the University of North Carolina at Chapel Hill.

Michael A. Gerlich joined Gastar in May 2005 as Vice President and Chief Financial Officer. Prior to joining Gastar Mr. Gerlich was Senior Vice President Accounting and Finance for Calpine Natural Gas L.P., formerly known as Sheridan Energy, Inc. He joined Sheridan Energy in July 1994 as Vice President and Chief Financial Officer. Over a 10 year period prior to joining Sheridan Energy, Mr. Gerlich held various accounting and finance positions with Trinity Resources, Ltd., with his last position being Executive Vice President and Chief Financial Officer. Mr. Gerlich was also with a big four accounting firm, where the focus of his practice was with energy related clients. Mr. Gerlich is a Certified Public Accountant and graduated with honors from Texas A&M University with a degree in accounting.

Frederick J. Lambert has been our Controller since May 2000. He additionally is the Controller of Geostar Corporation, a position he has held since February 1997. Previously, Mr. Lambert worked as a staff accountant for Shoemaker & Wilson, P.C., where the focus of the practice was oil and gas exploration and taxation. He is a graduate of Central Michigan University with a degree in Accounting and is a Certified Public

Accountant.

Sara-Lane Sirey, LLB is an independent contractor who has served as the Corporate Secretary of Gastar and General Corporate Canadian Counsel since May 2000. From July 1993 to April 2001, she served as an attorney at the law firm of Armstrong Perkins Hudson LLP (formerly Ogilvie and Company) in Calgary,

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Alberta, Canada, becoming a partner in 1999. Focusing on corporate/securities law, she has acted for issuers, in all industry segments, in Canada, the United States and internationally, focusing on corporate reorganizations, commercial transactions and initial public offerings of junior emerging companies as well as equity and debt financings, mergers and acquisitions and commercial transactions of senior established companies. Ms. Sirey obtained her Bachelor of Laws degree at the University of Saskatchewan in 1992.

Abby F. Badwi has been a member of our Board of Directors since February 2004. Mr. Badwi is an international energy executive with more than 30 years experience in the exploration, development and production of oil and gas fields in North America, South America, Asia and the Middle East. He is currently (and has been since July 2005) the President and CEO of Rally Energy, an oil and gas company with operations in Egypt, Pakistan and Canada. Since 2003, Mr. Badwi has also held the position of President of Corrundum Energy Ltd., a private company providing advisory services and investments in oil and gas ventures. From 2000 to 2002 he has served as President and CEO of Geodyne Energy Inc., an oil and gas exploration and production company. From 1994 to December 1999, Mr. Badwi served as President and Chief Operating Officer of Carmanah Resources Ltd., a Calgary, Alberta-based company with oil holdings in Canada, Indonesia and Venezuela. He has been an officer and director of several Canadian public and private companies and is currently a director of Arpetrol Inc., Gastar Exploration Ltd, Sustainable Energy Technologies Ltd., and Fairmount Energy Inc. Mr. Badwi is a geology graduate of the University of Alexandria, Egypt.

Thomas L. Crow has been a director since April 2002. Mr. Crow was the founder and President of Cobra Golf Inc. (a worldwide leading manufacturer of golf clubs which was listed on NASDAQ) from 1973 to 1994 and served as Vice President from 1994 to 1996 when Cobra Golf Inc. was acquired to be a subsidiary of Fortune Brand Inc. (a significant NYSE conglomerate). From 1997 to 2002, Mr. Crow remained as Chairman Emeritus of Cobra Golf Inc. Mr. Crow is currently an independent businessman.

Matthew J. P. Heysel joined our Board of Directors in January 2002. From 2000 until his resignation in May, 2005, Mr. Heysel served as Chairman of the Board of Directors and Chief Executive Officer of Big Sky Energy Corporation, an international oil and gas company. Mr. Heysel was also Chairman of Big Sky Energy Corporation s subsidiaries, Big Sky Energy Kazakhstan Ltd. and Big Sky Energy Atyrau Ltd. He also serves as the Chairman of both Big Sky Network Canada Ltd., a Canadian company located in Chengdu, China, to provide high speed internet technology services, and Chengdu Big Sky Technology Services Ltd., a Canadian company located in Calgary, Alberta to provide high speed internet technology services. From 1997 to 1999, Mr. Heysel served as an investment banker at Yorkton Securities, a Canadian independent securities firm, where he was responsible for corporate finance in the oil and gas sector. From 1987 to 1997, Mr. Heysel was with Sproule Associates Limited, Canada s largest petroleum engineering and geological consulting firm, holding the positions of Engineering Manager, Senior Associate, and Manager of International Projects. Mr. Heysel served as a Director of Canada s Petroleum Society from 1989 to 1992 and also sits as a board member of public and private oil and gas companies active in North America. Mr. Heysel obtained an Honours Bachelor s Science Degree from the University of Western Ontario in 1979, and a Bachelor of Science-Chemical Engineering from the University of Toronto in 1982 and has been a practicing professional Petroleum Engineer since that date.

Mr. Heysel obtained an Honours Bachelor s Science Degree from the University of Western Ontario in 1979, and a Bachelor of Science Chemical Engineering from the University of Toronto in 1982.

Richard Kapuscinski has been a member of our Board of Directors since July 2000. Mr. Kapuscinski is a Director of Marketing at Turbo Genset Inc, as the North American Business Development Manager since November 1999. Turbo Genset Inc. is a designer and manufacturer of innovative products for power generation and power conditioning. From 1986 to 1999, Mr. Kapuscinski worked as a Sales Marketing Manager with Tyco International (US) Inc. (formerly Keystone Valve), and from 1984 to 1986, he worked as an Engineering Technologist with Esso Petroleum. Mr. Kapuscinski is a Certified Mechanical Engineering Technologist and is a member of the Ontario Association of Certified Engineering Technicians and Technologists and the Instrument Society of America. He studied Mechanical Engineering at Lambton College in Sarnia, Ontario, Canada having a strong influence in the Petroleum and Petrochemical Industry.

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Executive Compensation

Summary of Compensation

The following table shows all compensation awarded or paid to, or earned by, our executive officers and certain named individuals for the years ending December 31, 2004, 2003 and 2002. Except as reflected in the following table, none of our executive officers received compensation in excess of $100,000 in any of the fiscal years ending December 31, 2004, 2003 or 2002.

Summary Compensation Table

		Annual Compensation			Long term Compensation		
					Awards	Payouts	
Name and Principal Position	Year	Salary	Bonus	Other Annual Compensation (1)	Securities Underlying Options	Long Term Incentive Plan Payments	All Other Compensation
Thomas E. Robinson	2004	$	$	$	500,000		
	2003						
Chairman of the Board and Chief Executive Officer (2)(3)	2002						
J. Russell Porter	2004	$ 350,000	$ 150,000		1,000,000		
	2003	$ 350,000					
Chief Executive Officer (4)	2002	$ 204,167					
Victor Hughes	2004				200,000		
	2003						
Former Chief Financial Officer (3)(5)	2002						
Frederick J. Lambert	2004	$ 46,875			150,000		
	2003						
Controller (3)(6)	2002						
Sara-Lane Sirey	2004				50,000		$ 69,848
	2003						$ 58,688
Corporate Secretary (7)	2002						$ 43,438

(1) As permitted by the rules promulgated by the Securities and Exchange Commission, no amounts are shown with respect to perquisites and other personal benefits, securities or property for each individual named in the table above that did not exceed the lesser of $50,000 or 10% of the sum of the amounts in the annual salary and bonus columns reported for such individual.

(2) Mr. Robinson resigned as Chief Executive Officer on February 17, 2004 but continues to hold the title of Chairman of the Board.

(3) Mr. Robinson, Mr. Hughes and Mr. Lambert received no cash compensation from us for any services performed by them.

(4) From September 2000 until February 17, 2004, Mr. Porter served as our Chief Operating Officer. Mr. Porter s salary for 2002, 2003 and 2004 was paid by Geostar. On February 17, 2005, Mr. Porter was appointed our Chief Executive Officer. Mr. Porter s bonus for 2004 was

paid by Gastar in 2005. Under the terms of his current employment agreement, he receives an annual base salary of $450,000, plus bonus.

(5) Mr. Hughes resigned in February 2005. Options granted to Mr. Hughes in 2004 were cancelled in May 2005 as a result of his resignation.

(6) Mr. Lambert acted as Interim Chief Financial Officer from February 2005 until May 17, 2005, the date on which Mr. Gerlich joined us as Vice President and Chief Financial Officer.

(7) Ms. Sirey, an independent contractor, acts as our Corporate Secretary. Cash amounts paid by us for her services are shown as Other Compensation.

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For additional information on cost sharing arrangements with Geostar, see Certain Relationships and Related Party Transactions .

Michael A. Gerlich joined us on May 17, 2005 as Vice President and Chief Financial Officer. Under the terms of his employment contract, Mr. Gerlich receives an annual base salary of $275,000.

Stock Option Grants and Exercises

The following table shows certain information about stock option grants to our executive officers and certain named individuals during the year ended December 31, 2004.

Name	Number of Securities Underlying Options/ SARs Granted	Percentage of Total Options/ SARs Granted to Employees in 2004	Strike Price (CDN$)	Expiration Date	Potential Realizable Value at Assumed Annual Rates of Stock Appreciation for Option Term (CDN$)	
					5%	10%
Thomas E. Robinson, Chairman of the Board and former Chief Executive Officer (1)	500,000	9.1%	3.41	08/04/09	471,060	1,040,920
J. Russell Porter, Chief Executive Officer (2)	1,000,000	18.2%	3.41	08/04/09	942,120	2,081,839
Victor Hughes, Former Chief Financial Officer (3)	200,000	3.6%	3.41	08/04/09	188,424	416,368
Frederick J. Lambert, Controller	150,000	1.8%	3.41	08/04/09	141,318	312,276
Sara-Lane Sirey, Corporate Secretary	50,000	0.9%	3.41	08/04/09	47,106	104,092

(1) Mr. Robinson resigned as Chief Executive Officer on February 17, 2004 but continued to hold the title of Chairman of the Board.
(2) On February 17, 2004, Mr. Porter was appointed our Chief Executive Officer. From September 2000 until February 17, 2004, he served as Chief Operating Officer.
(3) Mr. Hughes resigned in February 2005. Options granted to Mr. Hughes and unexercised were cancelled in May 2005 as a result of his resignation.

The following table shows information about stock options held as of December 31, 2004 by our officers and certain named individuals. None of our executive officers and certain named individuals exercised any stock options during 2004.

Name	Number of Securities Underlying Unexercised Options at December 31, 2004		Value of Unexercised in the Money Options at December 31, 2004 (1)	
	Exercisable	Unexercisable	Exercisable	Unexercisable
Thomas E. Robinson, Chairman of the Board and former Chief Executive Officer (2)	2,442,400	980,800	CDN$ 5,244,336	CDN$ 793,112

J. Russell Porter, Chief Executive Officer (3)	300,000	1,100,000	CDN$ 342,000	CDN$ 539,000
Victor Hughes, Former Chief Financial Officer (4)	700,000	300,000	CDN$ 1,782,000	CDN$ 212,000
Frederick J. Lambert, Controller	500,000	250,000	CDN$ 1,062,000	CDN$ 187,500
Sara-Lane Sirey, Corporate Secretary	700,000	150,000	CDN$ 1,782,000	CDN$ 138,500

(1) A per share price of CDN$3.90, the closing price on the Toronto Stock Exchange on December 31, 2004, was used for purposes of this calculation.

(2) Mr. Robinson resigned as Chief Executive Officer on February 17, 2004 but continued to hold the title of Chairman of the Board.

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(3) On February 17, 2004, Mr. Porter was appointed our Chief Executive Officer. From September 2000 until February 17, 2004, he served as Chief Operating Officer.
(4) Mr. Hughes resigned in February 2005. Options held by Mr. Hughes were cancelled in May 2005 as a result of his resignation.

On February 17, 2004, Mr. Porter was appointed our Chief Executive Officer. From September 2000 until February 17, 2004, he served as Chief Operating Officer.

Equity Compensation Plan Information

Our 2002 Stock Option Plan was approved and ratified by our shareholders on July 5, 2002. The 2002 Stock Option Plan superseded and replaced our prior stock-based compensation plans. Unexercised stock options granted under our prior stock option plans that had not expired or been cancelled on the effective date of the 2002 Stock Option Plan were ratified and confirmed as included under the 2002 Plan. Consequently, all currently outstanding stock options are subject to the terms of the 2002 Stock Option Plan.

The 2002 Stock Option Plan authorizes the issuance of options to purchase a maximum of 25 million common shares. If any option granted under the 2002 Stock Option Plan expires or terminates for any reason in accordance with the terms of the 2002 Stock Option Plan without being exercised, the unpurchased shares subject to that option will become available for other option grants under the 2002 Stock Option Plan. The 2002 Stock Option Plan is our only equity compensation plan.

We have reserved a maximum of 25.0 million common shares for issuance under the 2002 Stock Option Plan. As of September 30, 2005, we had options outstanding to purchase 17,425,850 common shares pursuant to the 2002 Stock Option Plan, 12,814,600 shares of which are vested but have not been exercised.

The 2002 Stock Option Plan is administered by our Board of Directors. Pursuant to the 2002 Stock Option Plan, our Board of Directors may allocate non-transferable options to purchase common shares to directors, officers, employees and consultants of Gastar and its subsidiaries. At the time of granting options under the 2002 Stock Option Plan, the aggregate number of common shares underlying all options granted under the 2002 Stock Option Plan and the aggregate number of common shares underlying the options granted to each individual under the 2002 Stock Option Plan may not exceed the maximum number permitted by any stock exchange on which our common shares are listed or by any other regulatory body having jurisdiction. Options issued pursuant to the 2002 Stock Option Plan have an exercise price determined by the Board of Directors, but that exercise price cannot be less than the price permitted by any stock exchange on which our common shares are then listed.

In April 2004, our Board of Directors amended the provisions of the 2002 Stock Option Plan to specifically incorporate a provision to provide for stock options to be exercised on a cashless basis whereby we issue the optionee the number of common shares equal to the stock option exercised, less the number of common shares which when multiplied by the market price at the date of exercise equals the aggregate exercise price for all of the common shares exercised.

We do not have any long term incentive plans other than the 2002 Stock Option Plan.

Employment Agreements and Termination of Employment and Change of Control Arrangements

We have entered into an employment agreement with our Chief Executive Officer and Chief Financial Officer. Each employment agreement shall continue unless terminated in accordance with the provisions of his respective agreement. Each employment agreement provides for a base salary, a bonus, participation in our health plans and other fringe benefits. The agreements also include confidentiality provisions.

Mr. Porter s 2005 annual base salary is $450,000, with an annual bonus not to be less than 20% of his annual salary. He received a bonus in 2004 of $150,000. Additionally, Mr. Porter will receive reimbursement for club and organizational membership used in furtherance of the Company s business. We will pay Mr. Porter severance benefits if his employment is terminated by death, disability, or if he or Gastar terminates his employment with proper notice. Severance benefits will be equal to two times his total compensation, as shown on his most recent Form W-2. Severance benefits will be payable over the Severance Pay Period , as set forth in his employment agreement. Mr. Porter will receive no severance payment if his termination is due to Reasonable Cause .

Mr. Gerlich s base salary is $275,000. Annual bonuses are at the discretion of the Company s board of directors. Upon becoming Chief Financial Officer, Mr. Gerlich was granted a stock option to acquire 250,000 shares of our common shares. Additionally, upon his employment s one year anniversary, he will be granted an additional stock option to acquire 125,000 common shares. We will pay Mr. Gerlich severance benefits if his employment is terminated by any reason other than Reasonable Cause . Severance benefits will be equal to two times his most recent annual compensation (exclusive of bonuses received or other non-cash compensation) if notice is received after May 17, 2006. If notice is received prior to May 17, 2006, the severance amount equal to one times his most recent annual compensation (exclusive of bonuses received or other non-cash compensation). Severance benefits will be payable over the Severance Pay Period , as set forth in his employment agreement.

Compensation of Directors

Commencing November 2005, the independent, non-employee and non-executive directors are to receive the following fees:

$7,500 for all meetings attended in person;

$1,500 per meeting attended telephonically; and

$500 per committee meeting attended in person.

The Chairman of the Board of Directors has elected to waive his future director meeting fees. All directors are reimbursed for certain expenses incurred in connection with their attendance of Board and committee meetings in accordance with company policy.

Directors are eligible to receive stock option grants under our 2002 Stock Option Plan. During the fiscal year ended December 31, 2004, we granted 500,000 stock options to the Chairman of the Board and 100,000 stock options to each remaining non-executive director at an exercise price of CDN $3.41.

Compensation Committee Interlocks and Insider Participation

From January 1, 2004 until May 28, 2004, the compensation committee of our Board of Directors, which we refer to as the Remuneration Committee, was comprised of Messrs. Crow, Kapuscinski, Heysel and Robinson. Other than Mr. Robinson who served as our Chief Executive Officer until February 17, 2004, no member of the Remuneration Committee was during the 2004 fiscal year or at any time prior to the 2004 fiscal year an officer or employee of us or any of our subsidiaries. As of May 28, 2004, our Remuneration Committee is comprised of Messrs. Badwi, Crow, Kapuscinski and Heysel, none of whom is or has ever served as an officer or employee of Gastar or any of its subsidiaries. None of our executive officers serves as a member of the board of directors or compensation committee (or committee performing similar functions) of any entity that has one or more executive officers who serve on our Board of Directors or Remuneration Committee.

Directors and Officers Liability Insurance

We carry directors and officers liability insurance with a policy limit of $20.0 million.

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SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth certain information about the beneficial ownership of common shares as of November 30, 2005 by:

Each of our directors;

Our executive officers named in the Summary Compensation Table above;

All of our directors and executive officers as a group; and

Each person known to us to be the beneficial owner of more than 5% of our outstanding common shares.

For purposes of the following table, a person is deemed to be the beneficial owner of securities that can be acquired by that person within 60 days from November 30, 2005 upon the exercise of warrants or options or upon the conversion of convertible securities. Each beneficial owner s percentage is determined by assuming that options, warrants or conversion rights that are held by that person regardless of price, but not those held by any other person, and which are exercisable within 60 days from November 30, 2005, have been exercised.

Unless otherwise indicated and subject to community property laws where applicable, we believe that all persons named in the following table have sole voting and investment power over all shares reported as beneficially owned by them. With the exception of Mr. Porter and Mr. Gerlich, the address for Geostar Corporation, Messrs. Ferguson, Lambert, Robinson, Badwi, Crow, Heysel and Kapuscinski and Ms. Sirey is 2480 W. Campus Drive, Building C, Mt. Pleasant, Michigan 48858. The address of Mr. Porter and Mr. Gerlich is 1331 Lamar Street, Suite 1080, Houston, Texas 77010.

The information in the following table is based upon information supplied by officers, directors, certain named individuals and principal shareholders. Applicable percentages are based on 163,592,086 common shares outstanding on November 30, 2005, subject to adjustment for each beneficial owner as described above.

Name of Beneficial Owner	Number of Common Shares Beneficially Owned	Percent of Class
Our 5% Owners:		
Chesapeake Energy Corporation	27,151,641	16.6%
Geostar Corporation	17,821,466	10.9%
Tony Ferguson (1)	12,422,827	7.5%
Our Officers, Directors and Certain Named Individuals:		
J. Russell Porter, Chief Executive Officer (2)	3,030,000	1.8%
Michael A. Gerlich, Vice President and Chief Financial Officer (3)		
Sara-Lane Sirey, Corporate Secretary (4)	581,086	*
Frederick J. Lambert, Controller (5)	837,500	*

Thomas E. Robinson, Chairman of the Board (6)	16,803,269	10.1%
Abby Badwi, Director (7)	75,000	*
Thomas Crow, Director (8)	512,500	*
Matt Heysel, Director (9)	253,078	*
Richard Kapuscinski, Director (10)	371,833	*
All officers, directors and certain named individuals as a group (9 persons)	22,464,266	13.4%

* Less than 1.0%.

(1) Includes direct ownership of 6,960,000 common shares, 3,414,627 common shares beneficially owned through Geostar Corporation and stock options to purchase 2,048,200 common shares, all of which are vested or will vest within 60 days of November 30, 2005.

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(2) Includes direct ownership of 2,280,000 common shares and stock options to purchase 750,000 common shares, all of which are vested or will vest within 60 days of November 30, 2005. On February 17, 2004, Mr. Porter was appointed our Chief Executive Officer. From September 2000 until February 17, 2004, he served as Chief Operating Officer.

(3) Mr. Gerlich was appointed our Vice President and Chief Financial Officer in May 2005.

(4) Includes direct ownership of 168,586 common shares and stock options to purchase 412,500 common shares, all of which are vested or will vest within 60 days of November 30, 2005.

(5) Includes direct ownership of 400,000 common shares and stock options to purchase 437,500 common shares, all of which are vested or will vest within 60 days of November 30, 2005.

(6) Includes direct ownership of 10,299,658 common shares, 4,455,411 common shares beneficially owned through Geostar Corporation and stock options to purchase 2,048,200 common shares, all of which are vested or will vest within 60 days of November 30, 2005. Mr. Robinson resigned as Chief Executive Officer on February 17, 2004 but continued to hold the title of Chairman of the Board.

(7) Includes stock options to purchase 75,000 common shares, all of which are vested or will vest within 60 days of November 30, 2005.

(8) Includes direct ownership of 300,000 common shares and stock options to purchase 212,500 common shares, all of which are vested or will vest within 60 days of November 30, 2005.

(9) Includes direct ownership of 78,078 common shares and stock options to purchase 175,000 common shares, all of which are vested or will vest within 60 days of November 30, 2005.

(10) Includes direct ownership of 146,833 common shares and stock options to purchase 225,000 common shares, all of which are vested or will vest within 60 days of November 30, 2005.

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DESCRIPTION OF CAPITAL STOCK

The following description of our capital stock does not purport to be complete and is subject to, and qualified in its entirety by, our articles of incorporation and bylaws, which are exhibits to the registration statement of which this prospectus forms a part.

Common Shares

We have an unlimited number of common shares authorized under our articles of incorporation. We have no other authorized classes of capital stock.

As of September 30, 2005, we had outstanding 136,440,445 common shares and we had reserved 27,267,426 shares for issuance upon exercise or conversion of outstanding options, warrants and convertible securities. An additional 25.0 million of our common shares have been reserved for issuance under our 2002 Stock Option Plan, under which options to purchase 17,425,850 common shares were outstanding as of September 30, 2005. After reflecting the purchase 27,151,641 common shares by Chesapeake on November 4, 2005, we have 163,592,086 common shares outstanding.

In addition to the foregoing reserved shares, we also issued subscription receipts in connection with the issuance of our senior secured notes in June and September 2005, entitling the holders to receive on each of the six, twelve and eighteen-month anniversaries of the note closings, newly issued common shares equal in market value to CDN$4.5 million and CDN$714,286, respectively, based upon then current market prices. We may also be required to issue additional common shares to Geostar in the future based on the results of certain East Texas drilling, as described in Certain Relationships and Related Transactions.

Our common shares have been approved for listing on the American Stock Exchange and are expected to trade on that exchange shortly after the date of this prospectus under the symbol GST .

Common Share Purchase Warrants

As of September 30, 2005, we had warrants outstanding to acquire 2,992,261 shares of our common stock as follows:

Outstanding in Connection with:	Number of Warrants	Exercise Price	Date Granted	Expiration Date
$3.25 million private placement of 10% unsecured subordinated notes	232,521	$2.76 - 3.03	04/20/04 - 07/12/04	04/20/09 - 09/12/09
$15.0 million private placement of 15% senior notes dated July 24, 2004	510,525	$3.23	06/24/04	10/13/07
	1,989,475	$3.63	10/13/04	10/13/07

$10.0 million private placement of 15% senior notes dated October 7, 2004				
$30.0 million private placement of 9.75% convertible senior unsecured debentures	259,740	CDN $4.65	11/15/04 and 11/16/04	05/12/06

Subscription Receipts

In addition to 1,423,623 of our common shares issued to purchasers of $73.0 million of our senior secured notes upon issuance of the notes, we issued subscription receipts to the purchasers entitling them to receive for no additional consideration a number of shares on each of the six, twelve and eighteen-month anniversary dates of the issuance dates of the senior secured notes. Subscription receipts were issued entitling the holders to be issued for no additional consideration on each such December 17, 2005, June 17, 2006 and December 17, 2006 an aggregate number of common shares equal to CDN$4.5 million ($3.6 million) divided by the five-day weighted average trading price of common shares immediately prior to such date on the principal market or exchange where such shares trade. Additional subscription receipts were issued in connection with issuance of $10.0 million of additional senior secured notes entitling the holders to be issued for no additional consideration on each such March 19, 2006, December 19, 2006 and March 19, 2007 an aggregate number of common shares equal to CDN$714,286 ($606,000) divided by the five-day weighted average trading price of common shares immediately prior to such date.

On December 19, 2005, pursuant to the Senior Secured Notes, we issued to the Senior Secured Notes holders, for no additional consideration, an additional 1,082,105 common shares valued at CDN$4.1586, the five day weighted average trading price immediately prior to the date of issuance. Such shares were issued to the purchasers of the Senior Secured Notes on the six month anniversary of the original $63.0 million note issuance pursuant to subscription receipts.

We have the right under certain circumstances to require purchasers of our senior secured notes to purchase up to an additional $10.0 million principal amount of our senior secured notes on certain dates on or prior to June 16, 2007. See Description of Our Indebtedness Senior Secured Notes . If additional notes are issued, the purchasers will also be entitled to receive, for no additional consideration and on similar terms as those previously issued to the purchasers, on the issuance date of the additional senior secured notes and on each of the six, twelve and eighteen-month anniversary dates of the additional notes issuance dates, additional common shares and subscription receipts for common shares in an aggregate number equal to one-fourteenth of the principal amount of the additional notes being issued (expressed in Canadian dollars assuming for this purpose only a one for one conversion ratio with the U.S. dollar principal amount) divided by the five-day weighted average trading price of common shares immediately prior to such date on the principal market or exchange where such shares trade.

Under the terms of the securities purchase agreement with the purchasers of the senior secured notes, we may not at any time issue common shares to any purchaser of these securities to the extent the issuance of common shares would cause the purchaser and its affiliates to beneficially own more than 9.9% of our outstanding common shares. In addition, the aggregate common shares issuable pursuant to securities purchase agreement, including those issuable pursuant to the subscription receipts, are limited to the maximum number that may be issued without breaching our obligations under the rules and regulations of the principal market or exchange where our common shares trade, which currently is the Toronto Stock Exchange. In the event our issuances reach that maximum, the issuances to note holders would be proportionately reduced, and we would be required to pay cash for such unissued shares based on the formula for determining the number of shares required to be issued. Based on our recent trading prices and the rules of the Toronto Stock Exchange in effect as of the date of this prospectus, we do not expect that issuances of shares pursuant to our outstanding subscription receipts will be limited by this cap on the maximum number of shares issuable.

In the event of a change of control or upon a sale of substantially all of our assets or a reorganization or merger where we are not the surviving entity, the purchasers may require the Company to accelerate the issuance of our common shares pursuant to the subscription receipts.

Voting Rights

Holders of our common shares are entitled to vote at all meetings of our shareholders, with each share having one vote.

Our board of directors must call an annual meeting of shareholders to be held not later than 15 months after the last preceding annual meeting of shareholders and may, at any time, call a special meeting of shareholders.

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For purposes of determining the shareholders who are entitled to receive notice of a meeting of shareholders, the board of directors may, in accordance with the *Business Corporations Act* (Alberta) and National Instrument 54-101, fix in advance a date as the record date for that determination of shareholders, but that record date may not be more than 50 days or less than 35 days before the date on which the meeting is to be held.

The guidelines of National Instrument 54-101 and the provisions of the Business Corporations Act (Alberta) provide that notice of the time and place of a meeting of shareholders must be sent to each shareholder entitled to vote at the meeting, each director and to our auditors, not more than 50 days and not less than 21 days prior to the meeting. Our Bylaws provide that a quorum of shareholders is present at a meeting if at least 5% of the shares entitled to vote at a meeting are present in person or by proxy. A shareholder may participate in a meeting by means of telephone or other communication facilities that permit all persons participating in the meeting to hear each other.

In the case of joint shareholders, one of the holders present at a meeting may, in the absence of the other holder(s) of the shares, vote the shares. If two or more joint shareholders are present in person or by proxy, then they are to vote as one on the shares held jointly by them. If there is a disagreement between joint shareholders, they are considered to have abstained from voting.

Amendments to Articles of Incorporation and Bylaws

An amendment to our articles of incorporation requires the approval of not less than two-thirds of the votes cast by the holders of our common shares at a meeting of the shareholders.

An amendment to our Bylaws requires the approval of not less than 51% of the votes cast by the holders of our common shares at a meeting of the shareholders.

Dividends

Our shareholders are entitled to receive such dividends and other distributions on the our common shares as the board of directors declares from time to time. Pursuant to the provisions of the *Business Corporations Act* (Alberta), we may not declare or pay a dividend if there are reasonable grounds for believing that (1) we are, or would after the payment be, unable to pay our liabilities as they become due or (2) the realizable value of our assets would thereby be less than the aggregate of our liabilities and stated capital of all classes. We may pay a dividend by issuing fully paid shares, or in money or property. If shares of a subsidiary or affiliate of Gastar are issued in payment of a dividend, the declared amount of the dividend stated as an amount of money will be added to the stated capital account maintained or to be maintained for shares of the class or series issued in payment of the dividend. We do not expect to pay any dividends to our shareholders for the foreseeable future, but intend to retain any future earnings for our operational and other cash needs. Further, our current senior secured notes prohibit us from paying cash dividends for so long as the notes remain outstanding.

No Preemption Rights; Limited Restrictions on Directors Authority to Issue Shares

Existing shareholders have no rights of preemption or first refusal under our articles of incorporation or under the laws of Alberta with respect to future issuances of our common shares. Subject to the policies of The Toronto Stock Exchange, our board of directors has the authority to issue additional common shares. The policies of The Toronto Stock Exchange stipulate that the issuance price must not be lower than the market price, less the maximum prescribed discount (which varies based on the market price), and that an exercise or conversion price of convertible securities must not be lower than the market price on the date of the issuance of the security.

Board of Directors; Election and Removal of Directors

Holders of our common shares at each annual general meeting of shareholders are required to elect directors to hold office for a term expiring not later than the close of the next annual general meeting of shareholders unless a director resigns, dies or is required to resign pursuant to a regulatory ruling (for example, if a director has violated disclosure or insider reporting provisions of the applicable securities laws and has received regulatory penalties for such violations which include prohibiting the director from serving on the board). The board of directors may fill vacancies and, as provided by our articles of incorporation, may also appoint additional directors between annual general meetings of shareholders, but the number of additional directors so appointed may not exceed the number that is one-third of the number of directors appointed at the last annual general meeting of shareholders.

At least half of our directors must be resident Canadians, unless we earn less than 5% of our consolidated gross revenues (as shown in our consolidated financial statements as at the end of our more recently completed financial period) in Canada, in which case at least one-third of our directors must be resident Canadians. For the fiscal year ending December 31, 2004, we derived less than 5% of our consolidated gross revenues from sources in Canada; consequently, only one-third of our directors are required to be resident Canadians.

Any director may convene a meeting of directors. A minimum of 48 hours notice must be given before a meeting of directors. A majority of the directors constitutes a quorum at a meeting of directors. Every resolution submitted to a meeting of directors is decided by a vote of a majority of the directors participating in the meeting and the declaration of the chairman of the meeting on the result of the vote is final. In the case of a tie vote, the chairman does not have a tie-breaking vote.

Conflicts of Interest

A director who is a party to a material contract or proposed material contract with Gastar, or who has a material interest in any person who is a party to a material contract or proposed material contract with Gastar, is required to disclose in writing to us or request to have entered in the minutes of meetings of the directors the nature and extent of his interest.

A director who has a material interest in a material contract or proposed material contract with Gastar cannot vote on any resolution to approve the contract unless the contract is:

- An arrangement by way of security for money lent to or obligations undertaken by him, or by a body corporate in which he has an interest, for the benefit of Gastar or an affiliate;
- A contract relating primarily to his remuneration as a director, officer, employee or agent of Gastar or an affiliate;
- A contract for indemnity or insurance; or
- A contract with an affiliate.

Subject to a solvency test imposed by the *Business Corporations Act* (Alberta) and to the U.S. securities laws described below, we may give financial assistance by means of a loan, guarantee or otherwise to:

Any person on account of expenditures incurred or to be incurred on behalf of Gastar; and

To employees of Gastar or any of its affiliates to enable or assist them to purchase accommodation for their occupation.

In accordance with a share purchase or option scheme.

The fact that a person is a director does not prevent Gastar from providing him with such financial assistance if the director would otherwise qualify for it.

Under the U.S. securities laws, we are prohibited from directly or indirectly extending or maintaining credit, arranging for the extension of credit or renewing an extension of credit, in the form of a personal loan to or for any of the directors or executive officers of Gastar, except in certain circumstances. This prohibition does not apply to extensions of credit maintained by Gastar on July 30, 2002, but applies to any renewal or material modification of such existing credit.

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Anti-takeover Laws

In Canada, takeovers are governed by provincial securities laws and the rules of applicable stock exchanges. While the rules may vary among the provinces, a party who acquires 10% of the voting or equity securities of any class of a company will generally be deemed to be an insider of that company and will, among other things, be required to file both a news release and a prescribed form with applicable provincial regulatory authorities. The purchaser (including any party acting jointly or in concert with the purchaser) will be prohibited from purchasing any additional securities of the class of the target company previously acquired for a period commencing on the occurrence of an event triggering the filing requirement and ending on the expiry of one business day following the filing. This filing process, and the associated prohibition on further acquisition, will also apply in respect of every additional 2% or more of the target company s securities of the same class that are subsequently acquired, provided that the prohibition on further acquisition does not apply to a purchaser that owns 20% or more of the outstanding securities of that class.

An offer to acquire outstanding voting or equity securities of a class, where the securities subject to the offer, together with the offeror s securities, constitute in the aggregate 20% or more of the outstanding securities of that class of securities at the date of the offer, will trigger the take-over bid provisions of applicable provincial securities legislation (and, if applicable, the rules of applicable stock exchange(s)). Unless the bid is otherwise exempt, a take-over bid will require the bidder to prepare and mail to each shareholder a circular outlining the details of the bid and instructions regarding the tendering of the target shares. While a target company will generally provide a shareholder list to a bidder, there may be circumstances in which the bidder will need to go to court to obtain one, resulting in a delay in the process. Each shareholder must be offered the same consideration for its shares and the offer must be left open for at least 35 days. Depending on the circumstances and the parties involved, valuations of the target company and its operations may be required in support of the bid.

In addition to the foregoing, certain other Canadian legislation may limit a Canadian or non-Canadian entity s ability to acquire control over or a significant interest in us, including the Competition Act (Canada) and the Investment Canada Act (Canada). Issuers may also approve and adopt shareholder rights plans or other defensive tactics designed to be triggered upon the commencement of an unsolicited bid and make the company a less desirable take-over target.

Limitation of Liability and Indemnification

The *Business Corporations Act* (Alberta) and our bylaws provide that we will indemnify each of our directors and officers and any person who acts or acted at our request as a director or officer of a body corporate of which we are or were a shareholder or creditor, and the heirs and legal representatives of each of them, against all costs, charges and expenses reasonably incurred by such director, officer or person, and their respective heirs or legal representatives, in respect of any action or proceeding to which any of them is made a party by reason of such director, officer or person being or having served in that position, if: (1) the director, officer or person acted honestly and in good faith with a view to the best interests of us; and (2) in the case of a criminal or administrative action or proceeding that is enforced by a monetary penalty, the director, officer or person had reasonable grounds for believing that his conduct was lawful. As used above, costs, charges and expenses includes but is not limited to the fees, charges and disbursements or legal counsel on an as-between-a solicitor-and-the-solicitor s-own-client basis and an amount paid to settle an action or satisfy a judgment. These indemnities will continue in effect after the director or officer resigns his position or his position is terminated for any reason.

We have also entered into indemnification agreements with our directors and executive officers as described above in Management Executive Compensation Indemnification of Officers and Directors .

Insofar as indemnification for liabilities arising under the Securities Act may be permitted to directors, officers or persons controlling us under the indemnification arrangements described above, the SEC is of the opinion that this indemnification is against public policy as expressed in the Securities Act and is therefore unenforceable.

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Voluntary Liquidation and Dissolution

If we are depleted of resources and unable to meet our liabilities and ongoing continuous disclosure obligations under the *Business Corporations Act* (Alberta), our directors may propose, or a shareholder who is entitled to vote at an annual general meeting of shareholders may make a proposal for the voluntary liquidation and dissolution of Gastar.

A company may liquidate and dissolve upon receiving the approval of the shareholders by special resolution at a meeting duly called and held. Approval of a special resolution requires the affirmative vote of not less than two-thirds of the votes cast by the shareholders present at the meeting or by proxy.

Upon shareholder approval of dissolution by special resolution, the company would discharge all of its liabilities and thereafter distribute all of the assets remaining, if any, *pro rata* to all of the shareholders of the company. Articles of Dissolution would then be sent to the Registrar appointed under the *Business Corporations Act* (Alberta) and the Registrar would issue a Certificate of Dissolution. The company would cease to exist on the date shown in the Certificate of Dissolution.

Listing

Our common shares are listed on The Toronto Stock Exchange under the symbol YGA (YGA.TO in the U.S.) and are approved for listing, and may trade in the United States, on the American Stock Exchange under the symbol GST .

Transfer Agent and Registrar

The transfer agent and registrar for our common shares are CIBC Mellon Trust Company, at its principal office in Toronto, Ontario at 200 Queen Quay East, Unit 6, Toronto, Ontario, M5A 4K9.

Tax Issues

For a discussion of the material Canadian and U.S. federal income tax considerations, including withholding provisions and applicable treaties, associated with the ownership of our common shares by U.S. residents, please see Material Income Tax Consequences .

Other Canadian Laws Affecting U.S. Shareholders

There are no governmental laws, decrees or regulations in Canada relating to restrictions on the export or import of capital, or affecting the remittance of interest, dividends or other payments by us to non-residents of Canada. Dividends paid to U.S. tax residents, however, are subject to a 15% withholding tax (or a 5% withholding tax for dividends if the shareholder is a corporation owning at least 10% of the outstanding voting shares of the corporation) pursuant to Article X of the reciprocal tax treaty between Canada and the United States. Please see Material Income Tax Consequences .

There are no limitations specific to the rights of non-residents of Canada to hold or vote our common shares under the laws of Canada or the Province of Alberta, or in our articles of incorporation or bylaws, other than those imposed by the Investment Canada Act (Canada) as discussed below.

Non-Canadian investors who acquire a controlling interest in us may be subject to the Investment Canada Act (Canada), which governs the basis on which non-Canadians may invest in Canadian businesses. Under the Investment Canada Act (Canada), the acquisition of a majority of the voting interests of an entity (or of a majority of the undivided ownership interests in the voting shares of an entity that is a corporation) is deemed to be an acquisition of control of that entity. The acquisition of less than a majority but one-third or more of the voting shares of a corporation (or of an equivalent undivided ownership interest in the voting shares of the corporation) is presumed to be acquisition of control of that corporation unless it can be established that, on the acquisition, the

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corporation is not controlled in fact by the acquirer through the ownership of the voting shares. The acquisition of less than one-third of the voting shares of a corporation (or of an equivalent undivided ownership interest in the voting shares of the corporation) is deemed not to be acquisition of control of that corporation.

Registration Rights

We have agreed to register the resale of our common shares issued or issuable to certain of our security holders under the Securities Act of 1933, including the common shares offered by this prospectus. In some cases, we are also required to qualify such resales under applicable state securities laws. In the event of our election to issue additional senior secured notes, as described in Description of Indebtedness Senior Secured Notes , we agreed to file a registration statement within 30 days, and to use our best efforts to cause such a registration statement to become effective within 120 days, of such issuance related to the resale of any shares issuable in connection with the additional notes.

We will be required to pay penalties to holders of our senior secured notes in the event the registration statement of which this prospectus is a part is not effective by December 14, 2005, or if it ceases to be effective following effectiveness and the expiration of certain grace periods. Similar penalties will apply for additional registration statements that may be required to register any of the shares issued or issuable to holders of our senior secured notes. These penalties include a cash interest penalty based on the market trading value of the shares at the time of issuance to the note holders of 1.0% per month for each month that we are not in compliance with the registration requirements. In the event that a registration statement covering any shares issued or issuable to the note holders required to be filed by us is not declared effective on or before the applicable deadline for effectiveness, then, in addition to the applicable cash payments described above, we will be required to pay the note holders a per share amount in cash equal to the difference, if positive, by subtracting the five-day weighted average trading price of common shares on the principal market or exchange where such shares trade for the period immediately preceding the date on which the registration statement is declared effective by the Securities and Exchange Commission, from the applicable the five-day weighted average trading price for the period immediately preceding the five-day weighted average trading price of common for the period immediately preceding the applicable deadline for effectiveness.

We have also granted demand registration rights to Chesapeake with respect to the shares that they beneficially own. In addition, Chesapeake has the right to require us to register the resale of their shares, subject to limitations imposed by potential underwriters, in the event we determine to file a registration statement under the Securities Act of 1933, as amended, other than the registration statement of which this prospectus is a part. Geostar has been granted registration rights similar to those granted to the holders of the senior secured notes, other than the penalty provisions. These rights have been waived with respect to the registration statement of which this prospectus forms a part.

DESCRIPTION OF INDEBTEDNESS

Senior Secured Notes

On June 17, 2005, we issued senior secured notes totaling $63.0 million in principal amount, together with the issuance of 1,217,269 of our common shares in a private placement transaction. The notes are secured by substantially all of our assets, bear interest at the sum of the three-month LIBOR rate plus 6%, payable quarterly, and mature on June 18, 2010. The senior secured notes are redeemable in whole or in part prior to maturity at our option at any time after the first anniversary date of issuance upon payment of the principal and accrued and unpaid interest plus a premium ranging from three to five percent of redeemed principal plus interest paid; provided that a redemption at our option is not permitted following public announcement of certain pending, proposed or intended change of control transactions. Additionally, we agreed to issue the purchasers of the senior secured notes for no additional consideration, additional shares in increments valued at CDN$4.5 million on the issuance date and each of the six, twelve and eighteen-month anniversaries of the closing. See Description of Capital Stock Subscription Receipts .

On September 19, 2005, we issued to the holders of our senior secured notes an additional $10.0 million of senior secured notes on substantially the same terms as the original June 2005 private placement, including the issuance of 206,354 common shares to the note holders. The common shares issued in the transaction represented an aggregate value of CDN$714,286 based upon the five day weighted average trading price of CDN$3.4615 per share for the five trading days immediately prior to closing. In connection with the sale of the additional notes, we issued subscription receipts to the purchasers of the notes, for no additional consideration, entitling the holders to receive additional common shares in CDN$714,286 increments on each of the six, twelve and eighteen-month anniversaries of the closing date, valued on a five day weighted average trading price immediately prior to the date of issuance. We have the right on a quarterly basis to require the note holders to purchase up to an aggregate of $10.0 million principal amount of additional senior secured notes from November 2005 to June 16, 2007. If additional senior secured notes are issued, the purchasers will also be entitled to receive, for no additional consideration, additional common shares on similar terms as those issued with the original senior secured notes in a pro rata amount based on the additional principal amount of the senior secured notes.

On December 19, 2005, pursuant to the Senior Secured Notes, we issued to the Senior Secured Notes holders, for no additional consideration, an additional 1,082,105 common shares valued at CDN$4.1586, the five day weighted average trading price immediately prior to the date of issuance. Such shares were issued to the purchasers of the Senior Secured Notes on the six month anniversary of the original $63.0 million note issuance pursuant to subscription receipts.

The issuance of the additional senior secured notes is contingent upon compliance with reserves to net senior secured notes debt coverage ratios and other general covenants and conditions. Under the senior secured note, the PV(10) valuation is to be based on a third party independent reserve report utilizing constant pricing based on the lower of current natural gas and oil prices, adjusted for area basis differentials, or $6.00 per Mcf of natural gas and $40.00 per barrel of oil. From the first anniversary of the issuance of the notes up to the second anniversary of the issuance of the notes, proved reserves PV(10) (1P (PV10)) to net senior secured notes debt must be a minimum of 1.0:1. On the second anniversary date of the notes, the 1P PV(10) reserve ratio covenant increases to a minimum of 1.5:1 and it increases to 2.0:1 on the third anniversary date and for all test periods thereafter until maturity. Utilizing the same reserve pricing criteria above, the proved plus probable reserves PV(10) (2P PV(10)) to net senior secured notes debt reserve maintenance ratio covenant must be a minimum of 1.5:1 from date of issuance of the notes up to the first anniversary date and 2.0:1 to issue additional notes. On the first anniversary date of the senior secured notes, the 2P PV(10) reserve ratio maintenance covenant increases to a minimum of 2.5:1, on the second anniversary to 3.0:1 and on the third anniversary and for all test periods thereafter until maturity to 3.5:1. We must maintain compliance with the reserve ratio covenants at all future quarterly and annual covenant determination dates or be subject to mandatory principal redemptions under certain conditions.

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Our bank deposit accounts are subject to account control agreements in favor of our senior lenders that allow the senior lenders to control our cash and use it to pay interest and/or principal outstanding related to the senior secured notes.

Unsecured Subordinated Notes

On June 17, 2005, in connection with our acquisition from Geostar of additional interests in the Deep Bossier area of East Texas and the Powder River Basin, we issued in a private placement $32.0 million of unsecured, subordinated notes to Geostar. On August 11, 2005, we executed an agreement with Geostar whereby the Geostar $32.0 million unsecured subordinated note was cancelled. In conjunction with the note cancellation, we agreed to issue Geostar $17.0 million of our common shares issued at a value of CDN$3.25 and a new unsecured subordinated note for $15.0 million. The new Geostar note bears interest, payable monthly commencing February 15, 2006, at three-month LIBOR plus 4.5%. Pursuant to the terms of the Geostar agreement, we will utilize a portion of the proceeds of the Chesapeake transaction to pay the Geostar note in full.

Subordinated Unsecured Notes Payable

In 2004, we completed a $3.25 million subordinated unsecured note financing. The unsecured notes mature between April and September 2009, bear interest at 10% per annum and are callable by us after two years at 108% of the principal amount. The call premium reduces to 105% after three years and to 101% after four years. The subscribers were issued 232,521 warrants exercisable at prices ranging from $2.76 to $3.03 (CDN$3.64 to CDN$4.18) expiring at varying dates between April and September 2009 and were allocated a value of $235,000 per the Black-Scholes method. The allocated warrant value reduced the carrying value of the debt and is being amortized with other transaction costs to interest expense utilizing the effective interest rate method over the term of the unsecured notes.

Convertible Debentures

On November 12, 2004, we issued $30.0 million aggregate principal amount of 9.75% convertible senior unsecured subordinated debentures in a private placement. The notes were issued pursuant to an indenture dated as of November 12, 2004 between Gastar and CIBC Mellon Trust Company. The net proceeds of the convertible debentures were used to accelerate our drilling in East Texas and otherwise to fund our operations.

The convertible debentures are payable in cash at maturity on November 20, 2009. The convertible debentures bear interest at a rate of 9.75% per annum, payable quarterly in arrears on each February 12, May 12, August 12 and November 12, commencing on February 12, 2005. The convertible debentures are convertible, in whole or in part, at the option of the holders at any time prior to the close of business on November 19, 2009 into common shares at a conversion price of $4.38 per share. Upon conversion, all accrued but unpaid interest thereon up to but not including the conversion date will be paid in cash to the surrendering holder.

The convertible debentures are not redeemable, in whole or in part, on or before November 13, 2006, except upon a defined change of control of us. At any time after November 13, 2006, we may redeem the convertible debentures, in whole or in part, on the terms and conditions set forth in the indenture at a redemption price equal to par plus accrued but unpaid interest thereon, provided that the weighted average price of our common shares on The Toronto Stock Exchange for any 20 consecutive trading days in any 30 consecutive 30-day period ending on the fifth trading day preceding notice of redemption is at least 130% of the conversion price then in effect.

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SELLING SHAREHOLDERS

The selling shareholders may from time to time offer and sell pursuant to this prospectus all of the common shares covered by this prospectus, including shares issuable upon exercise of warrants, conversion of the convertible debentures and pursuant to subscription receipts. The selling shareholders may not offer or sell any of the warrants, convertible debentures or subscription receipts pursuant to this prospectus.

This prospectus relates to the offer and sale, from time to time, of up to 23,085,160 common shares of Gastar Exploration Ltd. issuable to the selling shareholders listed below. The common shares being offered by the selling shareholders are outstanding, issuable upon conversion of the convertible debentures, issuable pursuant to outstanding subscription receipts and upon exercise of warrants as follows:

1,049,038 common shares issued upon exercise of warrants that were granted in connection with the private placement of working interests in September 2002;

232,521 common shares to be issued upon exercise of warrants that were granted in connection with the private placement of $3.2 million of 10% subordinated unsecured notes payable in April and September 2004;

510,525 common shares to be issued upon exercise of placement agent warrants that were granted in connection with the private placement of $15.0 million of 15% unsecured senior notes in June 2004;

1,989,475 common shares to be issued upon exercise of placement agent warrants that were granted in connection with the private placement of $10.0 million of 15% unsecured senior notes in October 2004;

259,740 common shares to be issued upon exercise of placement agent warrants that were granted in connection with the private placement of $30.0 million of 9.75% convertible senior unsecured debentures in June 2004;

6,488,584 common shares to be issued upon conversion of $30.0 million of 9.75% convertible senior unsecured debentures issued in November 2004;

1,217,269 common shares issued in June 2005 in connection with the private placement of $63.0 million of senior secured notes in June 2005;

1,082,105 common shares issued to the purchasers of the Senior Secured Notes on the six month anniversary of the original $63.0 million note issuance pursuant to subscription receipts.

2,893,891 common shares, being the estimated number of shares that we are committed to issue under subscription receipts to the purchasers of $63.0 million of senior secured notes, for no additional consideration, in CDN$4.5 million increments on each of the six, twelve and eighteen-month anniversaries of the original note issuance date valued on a five-day weighted average trading price immediately prior to the date of issuance (assumed to be CDN$3.11);

206,354 common shares issued in September 2005 in connection with the private placement of an additional $10.0 million of senior secured notes in September 2005;

689,022 common shares, being the estimated number of shares that we are committed to issue under subscription receipts to the purchasers of an additional $10.0 million of senior secured notes, for no additional consideration, in CDN$714,286 increments on each of the six, twelve and eighteen-month anniversaries of the original note issuance date valued on a five-day weighted average trading price immediately prior to the date of issuance (assumed to be CDN$3.11); and

6,466,636 common shares issued in a private placement in June 2005.

This prospectus has not been filed in respect of, and will not qualify, any distribution of the common shares covered by this prospectus in any province in the territory of Canada.

The following table sets forth certain information concerning the number of common shares beneficially owned by each of the selling shareholders. The first numerical column sets forth the number of common shares

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beneficially owned by each of the selling shareholders prior to this offering, assuming the full exercise of all warrants and the conversion of all convertible debentures held by such shareholder. The second numerical column sets forth the number of common shares being offered each selling shareholder pursuant to this prospectus. The third numerical column sets forth the number of common shares to be owned by each of the selling shareholders upon completion of this offering, assuming the sale of all common shares offered by this prospectus and the percentage of the class outstanding represented by such number of common shares.

We prepared this table based on the information furnished to us by the selling shareholders named in the table below, and we have not sought to verify such information. This table only reflects information regarding selling shareholders who furnished such information to us. We expect that we will update this table as we receive more information from shareholders who have not yet furnished the requested information to us. Information regarding selling shareholders not named as of the date hereof and information regarding transferees of named selling shareholders will be set forth in supplements to this prospectus or, if required by applicable law, amendments to the related registration statement, in each case upon request and provision of all required information to us. Information regarding named selling shareholders may change from time to time after the date of this prospectus. Any changed information will be set forth in prospectus supplements or, if required by applicable law, amendments to the related registration statement if and when necessary. In addition, upon our being notified by a selling shareholder that a donee or pledgee intends to sell more than 500 shares, we will file a supplement to this prospectus specifically naming such donee. No offer or sale pursuant to this prospectus may be made by a shareholder unless that holder is named in the table below, in a supplement to this prospectus or, if required by applicable law, in an amendment to the related registration statement that has become effective.

Any or all of the common shares offered hereby may be offered for sale pursuant to this prospectus by the selling shareholders from time to time. Please see Plan of Distribution . Accordingly, no estimate can be given as to the amounts of common shares that will be held by the selling shareholders upon consummation of any such sales. We have assumed for purposes of the table below that all of the selling shareholders will sell all of the common shares offered hereby pursuant to this prospectus. In addition, the selling shareholders named below may have sold, transferred or otherwise disposed of, in transactions exempt from the registration requirements of the Securities Act, all or a portion of their warrants, convertible debentures and subscription receipts and the underlying common shares since the date on which the information regarding their beneficial ownership of common shares was provided to us.

The percentage of common shares beneficially owned upon completion of this offering is based on 163,592,086 common shares outstanding as of November 30, 2005. Except as otherwise noted, beneficial ownership is determined in accordance with Rule 13d-3 under the Exchange Act. Accordingly, a person is deemed to be the beneficial owner of securities that can be acquired by that person within 60 days from November 30, 2005 upon the exercise of warrants or options or upon the conversion of the convertible debentures. Each beneficial owner s percentage is determined by assuming that warrants or conversion rights that are held by that person, but not those held by any other person, and which are exercisable within 60 days from November 30, 2005, have been exercised. Unless otherwise indicated and subject to community property laws where applicable, we believe that each selling shareholder, and the named individual who is registering common shares held in a revocable trust or individual retirement account, has sole voting and investment power over all common shares reported as beneficially owned by such selling shareholder.

Common shares and subscription receipts issued for no additional consideration to purchasers of our senior secured notes in June and September 2005 were issued pursuant to a securities purchase agreement dated June 16, 2005, as amended. The material terms set forth in the securities purchase agreement are described in this prospectus under Description of Capital Stock Subscription Receipts and Description of Indebtedness Senior Secured Notes . The holders of our senior secured notes also have rights to require us to register the resale of common shares received in connection with the purchase of senior secured notes, as described in this prospectus under Description of Indebtedness Registration Rights . Under the terms of the securities purchase agreement with respect to the senior secured notes and the related common shares, we may not at any time issue common shares to any of the purchasers of these securities to the extent such issuance would cause the purchaser, together with its affiliates, to beneficially own more than 9.99% of our then outstanding common shares.

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Except as set forth below, to our knowledge, none of the selling shareholders has, or within the past three years has had, a material relationship with us or any of our affiliates, other than their ownership of securities as described below and the transactions contemplated by the agreements providing for the issuance of these securities as described in this prospectus. Unless otherwise noted, no selling shareholder would beneficially own 1% or more of the outstanding common shares following the sale of all shares offered hereunder.

Name of Beneficial Owner	Number of Common Shares Beneficially Owned	Number of Common Shares Offered Hereunder	Number of Outstanding Common Shares Owned After Completion of Offering
Advantage Advisors Catalyst International (8)(32)	18,200	15,000	3,200
Advantage Advisors Catalyst Partners LP (8)(32)	24,000	20,000	4,000
Aegon Capital Management Inc. (6)(33)	102,740	102,740	
Amethyst Arbitrage Fund (7)(34)	182,648	182,648	
Amethyst Arbitrage Trading Ltd. (7)(34)	65,069	65,069	
Anne L. Boucher UTMA (7)	6,849	6,849	
Aran Asset Management SA (9)	219,247	184,247	35,000
Arthur & Deborah Ablin CRUT (7)	11,416	11,416	
Arthur Ablin IRA (7)	45,662	45,662	
Atlas Master Fund Ltd. (8)(35)	141,509	141,509	
Bruce Macfarlane (7)	11,416	11,416	
Byron A. Adams, Jr. (8)	71,200	60,000	11,200
Canlis Family Living Trust (7)(36)	17,123	17,123	
Carol A. Chaffin Rev. Tr. (2)	7,093	7,093	
Carolyn A. Hougan (1)	5,128	5,128	
Caerus Fund Ltd. (6)(26)	45,662	45,662	
Chandler Hudson (7)	3,425	3,425	
Clifford A. Cantrell, Rev. Tr. (2)(37)	214,085	14,085	200,000
Cyrus Opportunities Fund II LP (10)	390,021	390,021	
Cyrus Opportunities Fund LP (11)	91,426	91,426	
D. Jackson Coleman (7)	6,849	6,849	
Donald A. Wright (14)(8)	150,000	150,000	
Donald Marquardt (1)	21,037	21,037	
Duncan Karcher and Cheryl Thellman (7)	3,425	3,425	
E. William Richardson, Trust dtd 12/16/89 (1)(38)	7,194	7,194	
Edward C. Droste (2)	7,143	7,143	
Edwin L. Wolff, Rev. Tr. (1)	110,313	30,000	80,313
Eric C. Johnson (1)	5,326	5,326	
Evan Jonovic IRA (12)	70,662	70,662	
Fidelity Commonwealth Trust: Fidelity Small Cap Stock Fund (8)(27)(39)	2,537,507	1,509,607	1,027,900
Fidelity Securities Fund: Fidelity Small Cap Value Fund (8)(27)(39)	3,098,011	2,264,411	833,600
Fledgling Associates LLC (13)	545,662	545,662	
Gaia Offshore Master Fund, Ltd. (14)(26)	1,200,179	1,200,179	
Global Gestion (6)(40)	104,662	45,662	59,000
Grey K Fund LP (8)(41)	56,604	56,604	
Grey K Offshore Fund Ltd. (8)(42)	84,905	84,905	
Heritage Mark Foundation (15)(43)	131,164	131,164	
HFTP Investment L.L.C. (16)(26)	2,328,671	2,328,671	
Ingalls & Snyder Value Partner, L.P. (17)(27)	1,700,000	1,700,000	
Ironman Energy Capital, L.P. (8)(44)	280,000	280,000	
J. Frederik Berg, Jr. (7)	7,991	7,991	

Name of Beneficial Owner	Number of Common Shares Beneficially Owned	Number of Common Shares Offered Hereunder	Number of Outstanding Common Shares Owned After Completion of Offering
James & Nancy C. Hanna Jt. Ten. (2)	7,169	7,169	
Jane M. Coleman (7)	6,849	6,849	
JMM Trading LP (8)(45)	286,000	286,000	
John & Jane Cefaly (7)	22,831	22,831	
John C. Gilmer (7)	43,379	43,379	
John E. & Lydia E. Olivia, Jt. Ten. (2)	6,850	6,850	
John Kirincich IRA (7)	45,662	45,662	
John S. Poindexter III (2)	263,429	7,143	256,286
Jose C., Jr. MD & Tina Dominguez (2)	6,780	6,780	
Judith S. Hart Living Trust (1)	13,966	13,966	
Kamal Sirageldin (7)	5,708	5,708	
Kevin Coccetti (2)(27)	27,247	7,247	20,000
Kevin Kirn (7)	3,425	3,425	
Kings Road Investment Ltd. (29)	1,569,863	1,569,863	
Leo J. & Jean E. Hertzog, JTWROS (2)	144,928	144,928	
Leonardo, L.P. (18)(28)	2,416,979	2,416,979	
Lieba Blask (7)	4,566	4,566	
Linda G. McEwen (2)	6,645	6,645	
Lionel K. Conacher Limited (6)	20,548	20,548	
Martin Solomon (19)	47,831	47,831	
Mary Lou Richardson Trust dtd 09/27/95 (1)(38)	9,020	9,020	
Matt & Sharlene Klein Trust (2)(47)	38,023	3,301	34,722
McCulloch Rev. Tr. (1)	91,905	40,000	51,905
Michael E. & Christine A. Pacanowsky (1)	25,000	25,000	
Michael S. Needleman (8)	10,000	10,000	
Middlemarch Partners Limited (6)(50)	365,297	365,297	
MM&P Holdings, a California partnership (7)(51)	37,397	27,397	10,000
Monty & Paula Franssen, Rev. Tr. (1)	88,500	25,000	63,500
Nancy M. Dana (7)	17,123	17,123	
Nicholas DiGiorgio (7)	45,662	45,662	
Neil Janovic (20)	70,662	70,662	
Nikolaos Monoyios, IRA (21)	314,155	314,155	
Nite Capital LP (8)(52)	72,500	72,500	
North Pole Capital Master Fund (6)(53)	445,205	445,205	
Patricia Katherine Magette, Rev. Tr. dtd 06/08/05 (1)	25,500	25,500	
Paul T. Hackspiel (2)	6,994	6,994	
Pete A. & Maureen P. Botting (1)	78,285	78,285	
Polaris Energy Offshore Master Fund (6)(54)	45,662	45,662	
Pritchard Capital Partners, LLC (5)(30)	21,948	21,948	
Puls Family Trust (2)(55)	7,143	7,143	
Quentin Boucher, Jr. UTMA (7)(56)	4,566	4,566	
RAB Energy Fund Ltd. (8)(57)	300,000	300,000	
Rappaport Gamma LP (1)(58)	488,550	488,550	
Rene Rodriquez-Sains (7)	7,991	7,991	
Richard A Groenendyke Jr. (7)	15,982	15,982	
Ridgecrest Partners LP (8)(59)	3,500	3,000	500
Ridgecrest Partners Ltd. (8)(32)	14,400	12,000	2,400
Ridgecrest Partners QP LP (8)(59)	89,900	80,000	9,900
Ritchie Energy Trading Ltd. (7)(60)	1,214,612	1,214,612	

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Name of Beneficial Owner	Number of Common Shares Beneficially Owned	Number of Common Shares Offered Hereunder	Number of Outstanding Common Shares Owned After Completion of Offering
Robert & Joan Burke (7)	3,425	3,425	
Robert Gillcash (7)	6,849	6,849	
Robert J. & Ruth J. Fink (1)	59,120	25,000	34,120
Ronald A. Johnson (1)	5,757	5,757	
S. M. Foote CRUT #1 (7)	6,849	6,849	
Sanford B. Prater (8)	20,000	20,000	
Schwencke LLC (1)(61)	244,275	244,275	
Sherif Sirageldin (7)	5,708	5,708	
Stephen B. & Deborah P. Moore (7)	2,283	2,283	
TD Asset Management Inc. (22)(27)(62)	500,093	219,593	280,500
Thomas Beug (7)	6,849	6,849	
Thomas O. Boucher IRA (7)	22,831	22,831	
U.S. Global Investors Global Resources Fund (23)(27)(63)	942,466	942,466	
Valerie A. Brackett (7)	228,311	228,311	
Wayland Recovery Fund LLC (24)(64)	482,909	482,909	
Wayzata Recovery Fund LLC (25)(64)	290,329	290,329	
Westwind Partners Inc. (5)(27)(65)	237,792	237,792	
	26,103,206	23,085,160	3,018,046

The following defined terms are used in the footnotes set forth below:

$15.0 Million 15% Unsecured Senior Notes Placement Agent Shares means common shares being offered consists of common shares to be issued upon exercise of placement agent warrants that were granted in connection with the private placement of $15.0 million of 15% unsecured senior notes in June 2004.

$10.0 Million 15% Unsecured Senior Notes Placement Agent Shares means common shares being offered consists of common shares to be issued upon exercise of placement agent warrants that were granted in connection with the private placement of $10.0 million of 15% unsecured senior notes in June 2004.

$63.0 Million Senior Secured Note Original Issue Shares means common shares being offered consists of common shares that have been issued in connection with the private placement of $63.0 million of senior secured notes in June 2005.

$63.0 Million Senior Secured Note 6 Month Additional Shares means common shares issued to the purchasers of the Senior Secured Notes on the six month anniversary of the original $63.0 million note issuance pursuant to subscription receipts.

$63.0 Million Senior Secured Note Original Issue Additional Shares means common shares being offered consists of common shares issuable upon exchange of outstanding subscription receipts, being the estimated number of shares that we are committed to issue to the purchasers of $63.0 million of senior secured notes, for no additional consideration, in CDN$4.5 million increments on each of the twelve and eighteen-month

anniversaries of the original note issuance date valued on a five-day weighted average trading price immediately prior to the date of issuance (assumed to be CDN$3.11).

$10.0 Million Senior Secured Note Original Issue Shares means common shares being offered consists of common shares that have been issued in connection with the private placement of an additional $10.0 million of senior secured notes in September 2005.

$10.0 Million Senior Secured Note Original Issue Additional Shares means common shares being offered consists of common shares, being the estimated number of shares that we are committed to issue to the

purchasers of an additional $10.0 million of senior secured notes, for no additional consideration, in CDN$714,286 increments on each of the six, twelve and eighteen-month anniversaries of the original note issuance date valued on a five-day weighted average trading price immediately prior to the date of issuance (assumed to be CDN$3.11).

(1) Common shares being offered consists of common shares that have been issued upon exercise of warrants that were granted in connection with the private placement of working interests in September 2002.

(2) Common shares being offered consists of common shares to be issued upon exercise of warrants that were granted in connection with the private placement of $3.2 million of 10% subordinated unsecured notes payable in April and September 2004.

(3) Common shares being offered consists of common shares to be issued upon exercise of placement agent warrants that were in granted connection with the private placement of $15.0 million of 15% unsecured senior notes in June 2004, which were acquired in a secondary transaction from the placement agent (Secondary $15.0 Million 15% Unsecured Senior Notes Placement Agent Shares).

(4) Common shares being offered consists of common shares to be issued upon exercise of placement agent warrants that were in granted connection with the private placement of $10.0 million of 15% unsecured senior notes in June 2004, which were acquired in a secondary transaction from the placement agent (Secondary $10.0 Million 15% Unsecured Senior Notes Placement Agent Shares).

(5) Common shares being offered consists of common shares to be issued upon exercise of placement agent warrants that were in granted in connection with the private placement of $30.0 million of 9.75% convertible senior unsecured debentures issued in November 2004 ($30.0 Million Underlying Convertible Debenture Placement Agent Shares).

(6) Common shares being offered consists of common shares to be issued upon conversion of $30.0 million of 9.75% convertible senior unsecured debentures issued in November 2004, which were acquired in a secondary transaction through the placement agent ($30.0 Million Underlying Convertible Debenture Shares).

(7) Common shares being offered consists of common shares to be issued upon conversion of $30.0 million of 9.75% convertible senior unsecured debentures issued in November 2004, which were acquired in a secondary transaction (Secondary $30.0 Million Underlying Convertible Debenture Shares).

(8) Common shares being offered consists of common shares that have been issued in a private placement in June 2005 (2005 Private Placement Shares).

(9) Common shares being offered consists of 34,247 $30.0 Million Underlying Convertible Debenture Shares (Note 8) and 150,000 Private Placement Shares (Note 14). Michael C. Thalmann, Chairman and CEO, holds voting and dispositive powers with respect to the offered securities.

(10) Common shares being offered consists of 78,253 $63.0 Million Senior Secured Note Original Issue Shares; 69,255 $63.0 Million Senior Secured Note 6 Month Additional Shares; 185,209 $63.0 Million Senior Secured Note Original Issue Additional Shares; 13,207 $10.0 Million Senior Secured Note Original Issue Shares; and 44,097 $10.0 Million Senior Secured Note Original Issue Additional Shares. Jenna Hwang, Steve Quinn and Rob Swenson share dispositive powers with respect to the offered securities.

(11) Common shares being offered consists of 18,356 $63.0 Million Senior Secured Note Original Issue Shares; 16,232 $63.0 Million Senior Secured Note 6 Month Additional Shares; 43,408 $63.0 Million Senior Secured Note Original Issue Additional Shares; 3,095 $10.0 Million Senior Secured Note Original Issue Shares; and 10,335 $10.0 Million Senior Secured Note Original Issue Additional Shares. Jenna Hwang, Steve Quinn and Rob Swenson share dispositive powers with respect to the offered securities.

(12) Common shares being offered consists of 5,105 Secondary $15.0 Million 15% Unsecured Senior Notes Placement Agent Shares (Note 3); 19,895 Secondary $10.0 Million 15% Unsecured Senior Notes Shares (Note 4); and 45,662 Secondary $30.0 Million Underlying Convertible Debenture Shares (Note 7). Evan Jarovic holds voting powers and shares dispositive powers with respect to the offered securities. Adam Jarovic has shared dispositive powers with respect to the offered securities.

(13) Common shares being offered consists of 102,105 Secondary $15.0 Million 15% Unsecured Senior Notes Placement Agent Shares (Note 3); 397,985 Secondary $10.0 Million 15% Unsecured Senior Notes Shares Placement Agent Shares (Note 4); and 45,662 Secondary $30.0 Million Underlying Convertible Debenture Shares (Note 7). Voting and dispositive powers shared by Hartz Trading, Inc., as manager of the shareholder, and Ron Bangs, vice president of Hartz Trading, Inc.

(14) Common shares being offered consists of 426,941 $30.0 Million Underlying Convertible Debenture Shares (Note 6); 154,574 $63.0 Million Senior Secured Note Original Issue Shares; 137,427 $63.0 Million Senior Secured Note 6 Month Additional Shares; 367,524 $63.0 Million Senior Secured Note Original Issue Additional Shares; 26,207 $10.0 Million Senior Secured Note Original Issue Shares; and 87,506 $10.0 Million Senior Secured Note Original Issue Additional Shares.

(15) Common shares being offered consists of 5,105 Secondary $15.0 Million 15% Unsecured Senior Notes Placement Agent Shares (Note 3); 19,895 Secondary $10.0 Million 15% Unsecured Senior Notes Shares Placement Agent Shares (Note 4); and 106,164 Secondary $30.0 Million Underlying Convertible Debenture Shares (Note 7).

(16) Common shares being offered consists of 684,931 $30.0 Million Underlying Convertible Debenture Shares (Note 6); 328,469 $63.0 Million Senior Secured Note Original Issue Shares; 292,168 $63.0 Million Senior Secured Note 6 Month Additional Shares; 781,351 $63.0 Million Senior Secured Note Original Issue Additional Shares; 55,716 $10.0 Million Senior Secured Note Original Issue Shares; and 186,036 $10.0 Million Senior Secured Note Original Issue Additional Shares.

(17) Common shares being offered consists of 347,158 $15.0 Million 15% Unsecured Senior Notes Placement Agent Shares and 1,352,842 $10.0 Million 15% Unsecured Senior Notes Placement Agent Shares. Voting and dispositive powers with respect to the offered securities are held by Robert L. Gipson, general partner of the shareholder.

(18) Common shares being offered consists of 483,043 $63.0 Million Senior Secured Note Original Issue Shares; 429,596 $63.0 Million Senior Secured Note 6 Month Additional Shares; 1,148,875 $63.0 Million Senior Secured Note Original Issue Additional Shares; 81,922 $10.0 Million Senior Secured Note Original Issue Shares; and 273,543 $10.0 Million Senior Secured Note Original Issue Additional Shares.

(19) Common shares being offered consists of 5,105 Secondary $15.0 Million 15% Unsecured Senior Notes Placement Agent Shares (Note 3); 19,895 Secondary $10.0 Million 15% Unsecured Senior Notes Placement Agent Shares (Note 4); and 22,831 Secondary $30.0 Million Underlying Convertible Debenture Shares (Note 7).

(20) Common shares being offered consists of 5,105 Secondary $15.0 Million 15% Unsecured Senior Notes Placement Agent Shares (Note 3); 19,895 Secondary $10.0 Million 15% Unsecured Senior Notes Placement Agent Shares (Note 4); and 45,622 Secondary $30.0 Million Underlying Convertible Debenture Shares (Note 7).

(21) Common shares being offered consists of 40,842 Secondary $15.0 Million 15% Unsecured Senior Notes Placement Agent Shares (Note 3); 159,158 Secondary $10.0 Million 15% Unsecured Senior Notes Shares Placement Agent Shares (Note 4); and 114,155 Secondary $30.0 Million Underlying Convertible Debenture Shares (Note 7).

(22) Common shares being offered consists of 68,493 Secondary $30.0 Million Underlying Convertible Debenture Shares (Note 7) and 151,100 2005 Private Placement Shares (Note 8).

(23) Common shares being offered consists of 342,466 Secondary $30.0 Million Underlying Convertible Debenture Shares (Note 7) and 600,000 2005 Private Placement Shares (Note 8).

(24) Common shares being offered consists of 96,609 $63.0 Million Senior Secured Note Original Issue Shares; 85,811 $63.0 Million Senior Secured Note 6 Month Additional Shares; 229,486 $63.0 Million Senior Secured Note Original Issue Additional Shares; 16,364 $10.0 Million Senior Secured Note Original Issue Shares; and 54,639 $10.0 Million Senior Secured Note Original Issue Additional Shares.

(25) Common shares being offered consists of 57,965 $63.0 Million Senior Secured Note Original Issue Shares; 51,616 $63.0 Million Senior Secured Note 6 Month Additional Shares; 138,039 $63.0 Million Senior Secured Note Original Issue Additional Shares; 9,843 $10.0 Million Senior Secured Note Original Issue Shares; and 32,866 $10.0 Million Senior Secured Note Original Issue Additional Shares.

(26) Each of Caerus Funds Ltd., Gaia Offshore Master Fund, Ltd. and HFTP Investment L.L.C. has advised us that it is not a registered broker-dealer, it does not control and is not controlled by a registered broker-dealer, and it is an affiliate of a U.S. registered broker-dealer due solely to its being under common control with a registered broker-dealer, which was not involved in the purchase, and will not be involved in the ultimate sale, of the common shares. Each of Caerus Funds Ltd., Gaia Offshore Master Fund, Ltd. and HFTP Investment L.L.C. has also advised us that it purchased the common shares in the ordinary course of its business, and at the time it purchased the common shares, it was not a party to any agreement or other

understanding to distribute the securities, directly or indirectly. Promethean Asset Management, LLC, a New York limited liability company (Promethean), serves as investment manager to HFTP Investment L.L.C. (HFTP), Gaia Offshore Master Fund, Ltd. (Gaia) and Caerus Fund Ltd. (Caerus) and may be deemed to share beneficial ownership of the securities beneficially owned by HFTP, Gaia and Caerus, as a result of Promethean s power to vote and dispose of securities in each of HFTP, Gaia and Caerus. The ownership information for each of these three selling shareholders does not include the ownership information for the others. Promethean disclaims beneficial ownership of the securities beneficially owned by HFTP, Gaia and Caerus, and each of HFTP, Gaia and Caerus disclaims beneficial ownership of the securities beneficially owned by the others. James F. O Brien, Jr. indirectly controls Promethean. Mr. O Brien disclaims beneficial ownership of the securities beneficially owned by Promethean, HFTP, Gaia and Caerus.

(27) Shareholder is an affiliate of U.S. registered broker-dealer that acquired the offered securities in the ordinary course of its business and, at the time of acquisition, had no arrangements, agreements or understandings, directly or indirectly, with any person to distribute the offered securities.

(28) Leonardo Capital Management, Inc. (LCMI) is the sole general partner of Leonardo, L.P. Angelo, Gordon & Co., L.P. is the sole director of LCMI. John M. Angelo and Michael L. Gordon are the principal executive officers of Angelo, Gordon & Co., L.P. and hold voting and dispositive powers with respect to the offered securities.

(29) Common shares being offered consist of 1,369,863 $30.0 Million Underlying Convertible Debenture Shares (Note 8) and 200,000 2005 Private Placement Shares (Note 14). Shareholder is a wholly-owned subsidiary of Polygon Global Opportunities Master Fund (Master Fund). Polygon Investment Partners LLP and Polygon Investment Partners LP (the Investment Managers), Polygon Investments Ltd. (the Manager), the Master Fund, Alexander Jackson, Reade Griffith and Paddy Dear share voting and dispositive power with respect to the offered securities held by the shareholder.

(30) Pritchard Capital Partners, LLC has advised us that it is a U.S. registered broker-dealer; however, it received these securities as compensation for investment banking services. Voting and dispositive powers with respect to the offered securities are held by Thomas W. Pritchard, managing director of the shareholder.

(31) Footnote not used intentionally.

(32) Sanford B. Prater, portfolio manager, holds voting and dispositive powers with respect to the offered securities.

(33) Mark Jackson, chief investment officer, holds voting and dispositive powers with respect to the offered securities.

(34) Crystalline Management Inc., a Canadian registered portfolio manager and investment advisor, has discretionary authority over the shareholder and as such has full authority to dispose of the offered securities and exercise voting power with respect to such offered securities. The following natural persons may exercise these rights for, or on behalf of, Crystalline Management Inc. and the offered securities - Marc Amirault, president and portfolio manager; Bradley P. Semmelhaack, portfolio manager; and Jean-Pierre Langevin, vice president and secretary.

(35) Voting and dispositive powers with respect to the offered securities is shared with RNK Capital, LLC, subadvisor to the shareholder. Natural persons who share such powers are Dimitry Balyasny, Scott Schroeder, and Robert Kolton.

(36) C.B. Canlis holds voting powers and shares dispositive powers with respect to the offered securities. Steven Foote has shared dispositive powers with respect to the offered securities.

(37) Voting and dispositive powers with respect to the offered securities are shared by Clifford A. Cantrell and Judith E. Cantrell, trustees of the shareholder.

(38) Voting and dispositive powers with respect to the offered securities are shared by E. William Richardson and Mary Lou Richardson, trustees of the shareholder.

(39) The entity is a registered investment fund (the Fund) advised by Fidelity Management & Research Company (FMR Co.), a registered investment advisor under the Investment Advisors act of 1940, as amended. FMR Co., 82 Devonshire Street, Boston, Massachusetts 02109, a wholly-owned subsidiary of FMR Corp. and an investment advisor registered under Section 203 of the Investment Advisors Act of 1940, is the beneficial owner of securities of the Company as a result of acting as investment advisor to various investment companies registered under Section 8 of the Investment Company Act of 1940.

Edward C. Johnson 3d, FMR Corp., through control of FMR Co., and the Fund each has sole power to dispose of the Securities owned by the Fund. Neither FMR Corp. nor Edward C. Johnson 3d, Chairman of

FMR Corp., has the sole power to vote or direct the voting of the shares owned directly by the Fund, which power resides with the Fund s Board of Trustees.

(40) Voting and dispositive powers with respect to the offered securities are shared by Sven Lehrann, director general and Jean Bernard Guyon, CEO-Global Energy and Natural Resources for Global Gestion, trustees of the shareholder.

(41) Voting and dispositive powers with respect to the offered securities are held by Robert Kolton, managing member for the general partner of the shareholder.

(42) Voting and dispositive powers with respect to the offered securities are held by Robert Kolton, managing member for the shareholder.

(43) Kenneth J. Foote holds voting powers and shares dispositive powers with respect to the offered securities. Steven Foote has shared dispositive powers with respect to the offered securities.

(44) Voting and dispositive powers with respect to the offered securities are held by G. Bryan Dutt, managing director of the general partner of the shareholder.

(45) Voting and dispositive powers with respect to the offered securities are shared by Glenn Hunt and Richard Hunig, limited partners of the shareholder.

(46) Voting and dispositive powers with respect to the offered securities are held by Lionel K. Conacher, president of the shareholder.

(47) Voting and dispositive powers with respect to the offered securities are held by Matthew D. Klein, trustee of the shareholder.

(48) Footnote not used intentionally.

(49) Voting and dispositive powers with respect to the offered securities are held by George W. McCulloch, trustee of the shareholder.

(50) Voting and dispositive powers with respect to the offered securities are held by Cecilia M. Kershaw, director of the shareholder.

(51) Voting and dispositive powers with respect to the offered securities are shared by Bryan Ezralow, as trustee of the Bryan Ezralow 1994 Trust; Marc Ezralow, as trustee of the Marc Ezralow 1997 Trust; and Marshall Ezralow, as trustee of the Ezralow Family Trust and general partner of Elevado Investment Company, each a general partner of the shareholder.

(52) Voting and dispositive powers with respect to the offered securities are held by Keith A. Goodman, manager of the general partner of the shareholder.

(53) Voting and dispositive powers with respect to the offered securities are held by Paul Sabourin, as chairman of the investment advisor to the shareholder, and Jay Lee, as trader for the investment advisor to the shareholder.

(54) Voting and dispositive powers with respect to the offered securities are held by Paul Sabourin, as chairman of the investment advisor to the shareholder, and Ed Peplinski, as trader for the investment advisor to the shareholder.

(55) Voting and dispositive powers with respect to the offered securities are held by James M. Puls, John Leo Puls and Robert Puls, trustees of the shareholder.

(56) Voting and dispositive powers with respect to the offered securities are held by Thomas O. Boucher, Jr.

(57) Voting and dispositive powers with respect to the offered securities are held by Garvin Wilson, investment manager for the shareholder.

(58) Voting and dispositive powers with respect to the offered securities are held by A.G. Rappaport, president of the general partner of the shareholder.

(59) Voting and dispositive powers with respect to the offered securities are held by Sanford B. Prater, general partner of the shareholder.

(60) Each of Ritchie Capital management, Ltd., as investment manager, and Ritchie Capital Management, LLC, as subadvisor, has voting and dispositive powers with respect to the offered securities. A.R. Thane Ritchie controls Ritchie Capital Management, Ltd. and Ritchie Capital Management, LLC. Mr. Ritchie disclaims beneficial ownership of the securities held by Ritchie Energy Trading Ltd.

(61) Voting and dispositive powers with respect to the offered securities are held by Barbara J. Reynolds, managing member of the shareholder.

(62) Voting and Dispositive powers for the Secondary $30.0 Million Underlying Convertible Debenture Shares is held by Ari Levy and Margot Naubie, portfolio managers; for 30,000 2005 Private Placement Shares is held by Doug Warwick and Gary Baker, portfolio managers; and for 121,100 2005 Private Placement Shares is held by Gary Baker and Gord MacDougall, portfolio managers.

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(63) Voting and dispositive powers with respect to the offered securities are held by Brian Hicks, co-portfolio manager of the shareholder.

(64) Voting and dispositive powers with respect to the offered securities are held by Patricia J. Halloran, managing member of the investment manager of the shareholder.

(65) Voting and dispositive powers are jointly shared among Lionel Conacher, president and CEO of the shareholder; Keith Harris, CFO of the shareholder; and Horst Hueneken, managing director of the shareholder.

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PLAN OF DISTRIBUTION

We are registering certain of our common shares that are either now outstanding or will be issued upon exercise of certain warrants, conversion of convertible debentures or the issuance of additional shares pursuant to subscription receipts issued to holders of our senior secured notes. We are also offering the opportunity to participate in the registration statement to other holders of some of our restricted securities. Shares covered in the registration will include common shares currently held by some holders and certain common shares to be issued in the future upon the exercise or conversion of our securities or pursuant to subscription receipts. We will not receive any of the proceeds of the sale of the common shares offered by this prospectus. The common shares may be sold from time to time to purchasers:

- Directly by the selling shareholders; or
- Through underwriters, broker-dealers or agents who may receive compensation in the form of discounts, concessions or commissions from the selling shareholders or the purchasers of the common shares from the selling shareholders.

The selling shareholders and any underwriters, brokers, dealers or agents that participate in the distribution of the common shares may be deemed to be underwriters within the meaning of the Securities Act, and any discounts, concessions, commissions or fees received by them and any profit on the resale of the common shares sold by them may be deemed to be underwriting discounts and commissions.

If the common shares are sold through underwriters or broker-dealers, the selling shareholders will be responsible for any underwriting discounts or commissions or agent s commissions.

The common shares may be sold in one or more transactions at:

- Fixed prices;
- Prevailing market prices at the time of sale;
- Prices related to prevailing market prices;
- Varying prices determined at the time of sale; or
- Negotiated prices.

These sales may be affected in transactions:

On any national securities exchange or quotation service on which the common shares may be listed or quoted at the time of the sale, including The Toronto Stock Exchange and the American Stock Exchange;

In the over-the-counter market;

In transactions otherwise than on such exchanges or services or in the over-the-counter market;

Through the writing and exercise of options, whether these options are listed on any options exchange or otherwise;

Through the settlement of short sales; or

Through any combination of the foregoing.

These transactions may include block transactions or crosses. Crosses are transactions in which the same broker acts as an agent on both sides of the trade. In connection with sales of the common shares, the selling shareholders may enter into hedging transactions with broker-dealers. These broker-dealers may in turn engage in short sales of the common shares in the course of hedging their positions. The selling shareholders may also sell the common shares short and deliver common shares to close out short positions; provided that, the short sales are made after the registration statement is declared effective, or loan or pledge common shares to broker-dealers that in turn may sell the common shares.

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The selling shareholders may pledge or grant a security interest in some or all of the common shares owned by them, and if they default in the performance of their secured obligations, the pledgees or secured parties may offer and sell the common shares from time to time pursuant to the prospectus. The selling shareholders also may transfer or donate the common shares in other circumstances, in which case the transferees, donees or other successors in interest will be the selling beneficial owners for purposes of the prospectus.

To our knowledge, there are currently no plans, arrangements or understandings between any selling shareholders and any underwriter, broker-dealer or agent regarding the sale of the common shares by the selling shareholders. Selling shareholders may choose not to sell any or all of the common shares offered by them pursuant to this prospectus. In addition, we cannot assure you that any such selling shareholder will not transfer, devise or gift the common shares offered hereby by other means not described in this prospectus. Any common shares that qualify for sale pursuant to Rule 144 or Rule 144A under the Securities Act may be sold under Rule 144 or Rule 144A rather than pursuant to this prospectus. There can be no assurance that any selling shareholder will sell any or all of the common shares registered pursuant to this registration statement of which this prospectus forms a part.

Our common shares are listed for trading on The Toronto Stock Exchange under the symbol YGA and are approved for listing, and may trade in the United States, on the American Stock Exchange under the symbol GST .

The selling shareholders and any other person participating in such distribution will be subject to applicable provisions of the Exchange Act and the rules and regulations promulgated thereunder, including Regulation M, which may limit the timing of purchases and sales of any of common shares by the selling shareholders and any other participating person. In addition, Regulation M may restrict the ability of any person engaged in the distribution of the common shares to engage in market-making activities with respect to the common shares. This may affect the marketability of the common shares and the ability of any person or entity to engage in market-making activities with respect to common shares.

Pursuant to the subscription agreements with the selling shareholders who hold convertible debentures, the form of which subscription agreement is filed as an exhibit to the registration statement of which this prospectus forms a part, we may be indemnified by the selling shareholders against liabilities, including liabilities under the Securities Act that may arise from any written information furnished to us by the selling shareholder specifically for use in this prospectus. Westwind Partners Inc. acted as a placement agent for the convertible debentures. Pursuant to agency agreements, under which our convertible debentures and senior secured notes were sold, we agreed to indemnify Westwind Partners Inc. and its officers, directors, shareholders, agents, employees and advisors against certain liabilities, including some liabilities under the Securities Act, or they will be entitled to contribution. We are indemnified by Westwind Partners Inc. and its officers, directors, shareholders, agents, employees and advisors against certain liabilities, including liabilities that may arise under the Securities Act, in accordance with the agency agreements, or we may be entitled to contribution. The Company has no on-going relationship with Westwind Partners Inc. other than it occasionally provides investment banking services, including acting as a placement agent or providing financial fairness opinions on transactions to our board of directors. We have also agreed to indemnify the selling shareholders that are holders of our senior secured notes and their officers, directors, shareholders, agents, employees and advisors against certain liabilities, including some liabilities under the Securities Act, or they will be entitled to contribution. To the best of our knowledge, no selling shareholders that are affiliated with a registered broker-dealer acquired securities in a manner other than in the ordinary course of its business or, at the time of acquisition, with any arrangement or understanding with any person to distribute the securities. Pritchard Capital Partners, LLC has advised us that it is a U.S. registered broker-dealer; however, it received these securities as compensation for investment banking services.

We have agreed to pay substantially all of the expenses incidental to the registration, offering and sale of the common shares covered by this prospectus to the public other than commissions, fees and discounts of underwriters, brokers, dealers and agents.

To comply with the securities laws of some jurisdictions, if applicable, the holders of common shares may offer and sell the common shares in such jurisdictions only through registered or licensed brokers or dealers. In

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addition, under certain circumstances, in some jurisdictions shares of the common shares may not be offered or sold unless they have been registered or qualified for sale in the applicable jurisdiction or an exemption from registration or qualification requirements is available and is complied with.

If required, at the time of a particular offering of common shares by a selling shareholder, a supplement to this prospectus will be circulated setting forth the name or names of any underwriters, broker-dealers or agents, any discounts, commissions or other terms constituting compensation for underwriters and any discounts, commissions or concessions allowed or reallowed or paid to agents or broker-dealers. We have no obligation to any selling shareholder to arrange an underwriting, or assist in providing for any proposed sale, of any of the common shares offered hereby.

We have agreed with some of the selling shareholders to keep the registration statement of which this prospectus forms a part effective for specified periods of time or until the occurrence of certain events. We may under certain circumstances suspend the use of this prospectus, upon notice to the selling shareholders, to update the registration statement of which this prospectus forms a part with periodic information or material non-public information as required by the Securities Act. We have agreed with some of the selling shareholders to use our reasonable efforts to limit these suspended periods to those required by the Securities Act or limit them to contractually specified limits.

Once sold under the registration statement of which this prospectus forms a part, the common shares will be freely tradeable in the hands of persons other than our affiliates.

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CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

Geostar is the beneficial owner of approximately 10.9% of our common shares. Thom Robinson serves as Chairman of the Board of Directors of Gastar and is an officer and director of Geostar.

On June 1, 2000, we entered into an agreement with Geostar, a significant shareholder, to settle accounts payable related to the development of natural gas and oil properties with the issuance of a floating convertible debenture for up to CDN$25.0 million. Under the agreement, Geostar would continue to provide funds for development and operations by allowing us to draw down on the debenture. Advances under the debenture were subject to Geostar s availability of funds and the approval of the requested advances by Geostar s board of directors. The debenture was payable in cash or convertible into common shares, at prevailing market prices at our option.

In 2001, we entered into a Participation and Operating Agreement, or POA, with Geostar. For the East Texas properties, the POA was replaced effective January 1, 2005 with a Joint Operating Agreement, or JOA. Pursuant to the terms of the original POA, which still governs West Virginia and certain of our Australian assets, we have the option to participate as a working interest partner in properties in which Geostar and its subsidiaries have interests in on an at cost basis, subject to our full due diligence review prior to our participation election. Upon agreeing to participate, we are responsible for its proportionate share of actual costs expended by Geostar and its subsidiaries to third parties on an at cost basis. The balances of $601,000 at December 31, 2004 and $39,000 at December 31, 2003 represented amounts owed to Geostar and its subsidiaries for natural gas and oil property development. The 2003 balance was settled in 2004 by cash payment. In 2004, pursuant to the terms of the POA, Geostar billed us $27,000 (2003 $369,000) for administrative overhead.

In 2004, we recorded $1.3 million in general and administrative costs for administrative and technical support provided by Geostar to us. Commencing April 1, 2004, we agreed with Geostar to replace the administrative fee with a cost sharing arrangement. As a result, Geostar charged us a proportionate amount of direct salary and shared premises rent expense for Geostar employees providing administrative and technical support services to us based on actual costs incurred. This cost sharing arrangement continued as long as Geostar is the operator of the properties. This arrangement resulted in 2004 charges of approximately $146,000 per month for the second and third quarter, $150,000 per month for the fourth quarter. We incurred approximately $115,000 in 2004 ($33,000 in 2003) of seismic reprocessing fees paid to a subsidiary of Geostar. The seismic reprocessing fees were capitalized to natural gas and oil properties.

Effective January 1, 2005, we entered into a JOA with Geostar covering an Area of Mutual Interest (AMI) in East Texas, with Gastar as a non-operator and Geostar as operator. Under the terms of the JOA, Geostar received overhead reimbursement equal to 12.5% of development costs for the first 10 wells drilled after the effective date, 10% of the development costs for the 11th through 20th wells and 8.5% of the developments costs for all subsequent wells. As a result, Geostar no longer charges us a proportionate amount of direct salary and shared premises rent expense for Geostar employees providing administrative and technical support services to us. At March 31, 2005, Geostar billed us $1.4 million, which was equal to 12.5% of development costs for the Greer #1 and F-K #2 wells. These amounts were paid subsequent to the end of the quarter. In conjunction with the execution of the JOA, we terminated the convertible debenture arrangement with Geostar and commenced operating the East Texas properties. Under the new arrangement, we are required to find financing for our share of future joint venture costs.

Effective January 1, 2005 we have agreed to hire and employ directly certain Geostar employees as members of the management team. We will invoice Geostar for their share of common costs, if applicable.

There is a receivable with a balance of $63,000 from Geostar as of September 30, 2005, which is related to revenue earned from the properties net of capitalized expenditures incurred during the period and estimated post closing adjustments. This amount, along with the final post-closing purchase price adjustments, will be settled as provided for in the Purchase and Sale Agreements between Geostar and us.

Concurrent with the private placement of senior secured notes on June 17, 2005, we closed the acquisition from Geostar of additional leasehold and working interest properties in the Hilltop area of East Texas and in the Powder River Basin of Wyoming and Montana. We paid Geostar a total of $68.5 million for the interests acquired from Geostar consisting of $30.5 million in cash, 1,650,133 common shares valued at CDN$4.50 per share and $32.0 million in unsecured subordinated notes maturing on January 31, 2006. The acquisition increased our working interest position in the Hilltop area from an average of over 70% to an average of over 90% and gave us operational control of the properties. The acquisition of additional Powder River Basin interests increased our working interest position from approximately 17% to approximately 38% in properties currently being developed through an existing joint venture.

On August 11, 2005, we executed an agreement with Geostar whereby the Geostar $32.0 million unsecured subordinated note was cancelled. In conjunction with the note cancellation, we issued Geostar 6,373,694 common shares, calculated by dividing $17.0 million by an assumed value of CDN$3.25 per share, and a new unsecured subordinated note for $15.0 million. The new Geostar note bears interest, payable monthly commencing February 15, 2006, at three-month LIBOR plus 4.5% and matures November 15, 2006. The note requires monthly principal payments of $1.5 million commencing February 15, 2006 and continuing for nine months thereafter with a final principal payment of $1.5 million due on November 15, 2006. We may elect to pay interest in kind through the issuance of additional notes with such notes maturing on January 15, 2007.

In addition, Geostar may be entitled to receive additional common shares at prevailing market prices based on look backs at June 30, 2006 and June 30, 2007 on the East Texas assets, based on a required number of drilled wells and net reserve additions valued at $1.50 per Mcf less attributable capital expenditures to Geostar s former ownership position on the East Texas development costs.

All related party transactions in the normal course of operations have been measured at the agreed to exchange amounts, which is the amount of consideration established and agreed to by the related parties and which is similar to those negotiated with third parties.

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MATERIAL INCOME TAX CONSEQUENCES

A brief description of certain provisions of the tax treaty between Canada and the United States is included below, together with a brief discussion of certain taxes, including withholding provisions, to which U.S. shareholders are subject under existing laws and regulations of Canada and the United States. The consequences, if any, of state and local taxes are not considered. The following information is general and security holders should seek the advice of their own tax advisors, tax counsel or accountants with respect to the applicability or effect on their own individual circumstances of not only the matters referred to herein, but also any state or local taxes.

Canadian Federal Income Tax Consequences Associated with our Common Shares

General. The following is a summary of the principal Canadian federal income tax consequences generally applicable in respect of the ownership of our common shares. The tax consequences to any particular holder of our common shares will vary according to the status of that holder as an individual, trust, corporation or member of a partnership, the jurisdiction in which that holder is subject to taxation, the place where that holder is resident and, generally, that holder s particular circumstances. This summary is applicable only to holders who are resident in the United States and are subject to United States tax, are not (and have never been) resident in Canada, hold their shares as capital property and do not (and will not) use or hold their shares in, or in the course of, carrying on business in Canada. For purposes of this discussion, a non-resident holder means a holder of our common shares who does not reside in Canada.

The following general discussion in respect of taxation is based upon management s understanding of the rules. No opinion was requested by us, or has been provided by our counsel or auditors, with respect to the Canadian income tax consequences described in the following discussion.

Dividend Withholding. We have not paid dividends on our common shares in any of the past three years and have no plans to pay dividends in the foreseeable future. Canadian federal tax legislation would require a 25% withholding from any dividends paid or deemed to be paid to our non-resident shareholders. However, shareholders resident in the United States and subject to United States tax would generally have this rate reduced to 15% pursuant to the tax treaty between Canada and the United States. The withholding tax rate on the gross amount of dividends is reduced to 5% if the beneficial owner of the dividend is a U.S. corporation which owns at least 10% of our voting stock.

The amount of stock dividends paid to non-residents of Canada would be subject to withholding tax at the same rate as cash dividends. The amount of a stock dividend (for tax purposes) would generally be equal to the amount by which our paid-up capital had increased by reason of the payment of such dividend. We will furnish additional tax information to shareholders in the event of such a stock dividend.

Capital Gains. A non-resident who holds common shares as capital property generally will not be subject to Canadian taxes on capital gains realized on the disposition of such shares unless the shares are taxable Canadian property within the meaning of the *Income Tax Act* (Canada), and no relief is afforded under any applicable tax treaty. Common shares generally will not be taxable Canadian property of a shareholder of us unless, at any time during the five-year period immediately preceding a disposition of such shares, not less than 25% of the issued shares of any class or series of our capital stock belonged to persons with whom the shareholder did not deal at arm s length, or to the shareholder together with such persons or unless the shares were acquired by the holder in one of several tax deferred exchanges for shares which were themselves taxable Canadian property.

A non-resident shareholder whose common shares constitute taxable Canadian property and who is a resident of the United States for purposes of the tax treaty between Canada and the United States generally would be exempt from Canadian tax on any capital gain realized on a disposition of those shares in any event, provided the shares do not derive their value primarily from Canadian real property (including Canadian resource properties). Management is of the view that common shares do not derive their value primarily from Canadian real property.

United States Federal Income Tax Consequences Associated with our Common Stock

The following is a general discussion of all material U.S. federal income tax consequences that may apply to a holder of our common shares. This discussion is based on the Internal Revenue Code of 1986, as amended, which we refer to as the Code, Treasury Department regulations promulgated under the Code, published Internal Revenue Service, or IRS, rulings, published administrative positions of the IRS, and court decisions that are currently applicable, any or all of which could materially and adversely change at any time, possibly on a retroactive basis. In addition, the discussion does not consider the potential effects, both adverse and beneficial, of any proposed legislation which, if enacted, could be applied at any time, possibly on a retroactive basis. The following discussion is not intended to be, nor should it be construed to be, legal or tax advice to any holder or prospective holder of our common shares. No opinion was requested by us, or is provided by our counsel, with respect to the U.S. federal income tax consequences described in the following discussion. Accordingly, holders and prospective holders of our common shares should consult their own tax advisors about the U.S. federal, state, local and Non-U.S. tax consequences of purchasing, owning and disposing of our common shares.

United States Federal Income Taxation of U.S. Holders. As used in this discussion, a U.S. Holder means a holder of our common shares who is (1) a citizen or individual resident of the United States, (2) a corporation or entity taxable as a corporation for U.S. federal income tax purposes that is created or organized in or under the laws of the United States or of any political subdivision thereof or the District of Columbia, (3) an estate whose income is taxable in the United states irrespective of source or (4) a trust if a court within the United States is able to exercise primary jurisdiction over the administration of the trust and one or more United States persons have the authority to control all substantial decisions of the trust.

This summary does not address the tax consequences to, and U.S. Holder does not include, persons subject to specific provisions of federal income tax law, such as tax-exempt organizations, qualified retirement plans, individual retirement accounts and other tax-deferred accounts, financial institutions, insurance companies, real estate investment trusts, regulated investment companies, broker-dealers, persons or entities that have a functional currency other than the U.S. Dollar, shareholders subject to the alternative minimum tax, shareholders who hold our common shares as part of a straddle, hedging or a conversion transaction, constructive sale or other arrangement involving more than one position, partners and other pass-through entities and persons holding an interest in such entities, and shareholders who acquired their common shares through the exercise of employee stock options or otherwise as compensation for services. This summary is limited to U.S. Holders who own our common shares as capital assets (generally, property held for investment). This summary does not address the consequences to a person or entity holding an interest in a shareholder or the consequences to a person of the ownership, exercise or disposition of any options, warrants or other rights to acquire our common shares. If a partnership (including an entity treated as a partnership for U.S. federal income tax purposes) holds our common shares, the tax treatment of a partner generally will depend upon the status of the partner and upon the activities of the partnership. If you are a partnership, or a partner in a partnership, holding common shares, you should consult your tax advisor.

Distributions on Our Common Shares. We have never paid any cash dividends on our common shares and do not anticipate paying any cash dividends in the foreseeable future. However, if U.S. Holders receive dividend distributions (including constructive dividends) with respect to our common shares such holders would be required to include in gross income for U.S. federal income tax purposes the gross amount of such distributions equal to the U.S. Dollar value of such distributions on the date of receipt (based on the exchange rate on such date) to the extent that we have current or accumulated earnings and profits, without reduction for any Canadian income tax withheld from such distributions. Such Canadian tax withheld may be credited, subject to certain limitations, against the U.S. Holder s U.S. federal income tax liability or, alternatively, may be deducted in computing the U.S. Holder s U.S. federal taxable income by those who itemize deductions. See Foreign Tax Credit , below. To the extent that distributions exceed our current or accumulated earnings and profits, they will

be treated first as a return of capital up to the U.S. Holder s adjusted basis in our common shares (and not subject to tax) and thereafter as gain from the sale or exchange of the common shares (which is taxable as capital gain). Subject to certain exceptions, dividends paid on our common shares generally will not be eligible for the dividends-received deduction available to corporations receiving dividends from certain United States corporations.

Dividends , if any, paid on our common shares to a U.S. Holder who is an individual, trust or estate (a U.S. Individual Holder) will be treated as qualified dividend income that is taxable to such U.S. Individual Holder at preferential rates (through 2008) provided that (i) we are eligible for the benefits of a comprehensive income tax treaty with the United States that has been determined to be satisfactory for this purpose (the U.S.-Canadian Treaty is included for this purpose); (ii) we are not a passive foreign investment company or PFIC for the taxable year during which the dividend is paid or the immediately preceding taxable year (which we do not believe we are or have been or will be); (iii) the U.S. Individual Holder has owned the common shares for more than 60 days in the 121-day period beginning 60 days before the date on which the common shares become ex-dividend; and (iv) the U.S. Individual Holder is not under an obligation to make related payments with respect to positions in substantially similar or related property.

Special rules may apply to any extraordinary dividend paid by us. An extraordinary dividend is, generally, a dividend equal to or in excess of 10 percent of a shareholder s adjusted basis (or fair market value in certain circumstances) in a share of common stock. If we pay an extraordinary dividend on our common shares that is treated as qualified dividend income , then any loss derived by a U.S. Individual Holder from the sale or exchange of common shares will be treated as long-term capital loss to the extent of such dividend.

Foreign Tax Credit. A U.S. Holder who pays (or has withheld from distributions) Canadian income tax with respect to the ownership of our common shares may be entitled, at his or her option, to either a deduction or a tax credit for such foreign tax paid or withheld. Furthermore, a U.S. Holder that is a domestic corporation that owns 10% or more of our voting stock may be eligible to claim a deemed paid foreign tax credit based on the underlying non-U.S. income taxes paid by us. Generally, it will be more advantageous to claim a credit because a credit reduces U.S. federal income taxes on a dollar-for-dollar basis, while a deduction merely reduces the taxpayer s income subject to tax. This election is made on a year-by-year basis and applies to all foreign income taxes (or taxes in lieu of income tax) paid by (or withheld from) the U.S. Holder during the year.

There are significant and complex limitations which apply to the foreign tax credit, among which is the general limitation that the credit cannot exceed the proportionate share of the U.S. Holder s U.S. federal income tax liability that the U.S. Holder s foreign source income bears to his or her or our worldwide taxable income. There are further limitations based on the type of income. In addition, any foreign tax credits may also be subject to special treaty limitations. The availability of the foreign tax credit, the deemed paid foreign tax credit, and the application of the limitations on the credit are fact-specific and holders and prospective holders of our common shares should consult their own tax advisors regarding their individual circumstances.

Sale, Exchange or other Disposition of Common Shares. Assuming we do not constitute a PFIC for any taxable year, a U.S. Holder generally will recognize taxable gain or loss upon a sale, exchange or other disposition of our common shares in an amount equal to the difference between the amount realized by the U.S. Holder from such sale, exchange or other disposition and the U.S. Holder s tax basis in such shares. Subject to the discussion of extraordinary dividends above, such gain or loss will be treated as long-term capital gain or loss if the U.S. Holder s holding period is greater than one year at the time of the sale, exchange or other disposition. Preferential tax rates for long term capital gains may apply to certain U.S. Holders who satisfy minimum holding period and other requirements. There are currently no preferential tax rates for long term capital gains for any U.S. Holder that is a corporation. A U.S. Holder s ability to deduct capital losses is subject to certain limitations.

Special Rules. In the following circumstances, the above sections of the discussion may not describe the U.S. federal income tax consequences resulting from the holding, receipt of dividends and disposition of

common shares. Management does not believe that we are a PFIC , or a controlled foreign corporation as those terms are defined below.

Passive Foreign Investment Company. A non-U.S. entity treated a corporation for U.S. federal income tax purposes will be a PFIC in any taxable year in which, after taking into account the income and assets of the corporation and certain subsidiaries pursuant to a look through rule, either (i) 75% or more of its gross income is passive income such as interest, dividends and certain rents and royalties or (2) at least 50% of the average value of its assets is attributable to assets that produce passive income or are held for the production of passive income. Management does not believe that we are a PFIC, or will be a PFIC in the future, because we are engaged primarily in the business of a natural gas and oil exploration and development. We have not received 75% or more of our gross income from passive sources, nor has 50% or more of the fair market value of our assets been held for the production of passive income. The taxation of a U.S. shareholder who owns stock in a PFIC is extremely complex and is beyond the scope of this discussion. U.S. persons should consult with their own tax advisors regarding the impact of these rules if we are or were to become a PFIC.

Controlled Foreign Corporation. A controlled foreign corporation or CFC is a foreign corporation more than 50% of the stock of which, by vote or value, is owned, directly, indirectly or constructively, by one or more U.S. shareholders who each owns, directly, indirectly or constructively, 10% or more of the total combined voting power of all classes of stock of the foreign corporation (each a CFC Shareholder). If we are a CFC, a CFC Shareholder would be treated as receiving current distributions of an allocable share of certain types of income. Additionally, such a CFC Shareholder would recognize ordinary income to the extent of an allocable share of our earnings and profits, rather than capital gain, on the sale of his or her common shares. Management does not believe that we are a CFC because shareholders who directly, indirectly or constructively control 10% or more of the total voting power of our outstanding common shares do not own more than 50% of our common shares.

United States Federal Income Taxation of Non-U.S. Holders. For purposes of this discussion, a beneficial owner of our common shares that is not a U.S. Holder (other than a partnership or entity treated as a partnership for U.S. federal income tax purposes) is a Non-U.S. Holder.

Distributions on our Common Shares. Distributions we pay to a Non-U.S. Holder will not be subject to U.S. federal income tax or withholding tax if the Non-U.S. Holder is not engaged in a U.S. trade or business. If the Non-U.S. Holder is engaged in a U.S. trade or business, distributions we pay will be subject to U.S. federal income tax at regular graduated rates if those distributions are effectively connected with that Non-U.S. Holder s U.S. trade or business and, if an income tax treaty applies, are attributable to a permanent establishment maintained by that Non-U.S. Holder in the United States. In addition, a branch profits tax may be imposed at a 30% rate, or a lower rate under an applicable income tax treaty, on dividends received by a non-U.S. corporation that are effectively connected with its conduct of a trade or business in the United States.

Sale, Exchange or other Disposition of Common Shares. Non-U.S. Holders generally will not be taxed on any gain recognized on a disposition of our common stock unless the gain is effectively connected with the Non-U.S. Holder s conduct of a trade or business in the United States and, if an income tax treaty applies, is attributable to a permanent establishment maintained by the non-U.S. holder in the United States. If the Non-U.S. Holder is engaged in a U.S. trade or business and the gain is effectively connected with that trade or business (and if a tax treaty applies, is attributable to a permanent establishment maintained by such Non-U.S. Holder in the United States), such gain will be subject to U.S. federal income tax at regular graduated rates and, if the Non-U.S. Holder is a corporation, the branch profits tax described above may also apply. A Non-U.S. Holder who is an individual and who is present in the United States for 183 days or more in the taxable year of the disposition and meets other requirements also will be subject to U.S. federal income tax on gain recognized on a disposition of our common stock.

Information Reporting and Backup Withholding Tax. In general, dividend payments or other taxable distributions made within the United States will be subject to information reporting and U.S. backup withholding tax if a U.S Individual Holder fails to provide an accurate taxpayer identification number certified under

penalties of perjury, as well as certain other information or otherwise establish an exemption from backup withholding.

Non-U.S. Holders may be required to establish their exemption from information reporting and backup withholding by certifying their status on an IRS Form W-8BEN, W-8ECI or W-8IMY as applicable.

If a Non-U.S. Holder sells shares to or through the U.S. office of a U.S. or foreign broker, the payment of the proceeds generally will be subject to information reporting requirements and backup withholding unless the Non-U.S. Holder properly certifies its non-U.S. status under penalties of perjury or otherwise establishes an exemption. Information reporting requirements and backup withholding generally will not apply to any payment of the proceeds of the sale of common shares affected outside the United States by a foreign office of a broker. However, U.S. information reporting requirements (but not backup withholding requirements) will apply to payment of the sales proceeds if the broker is a United States person or has certain other contacts with the United States.

Backup withholding is not an additional tax. Rather, a holder generally may obtain a refund of any amounts withheld under the backup withholding rules that exceed such holder s U.S. federal income tax liability by timely filing a properly completed claim for refund with the U.S. Internal Revenue Service.

LEGAL MATTERS

The validity of the common shares offered by this prospectus will be passed upon for us by Sara-Lane Sirey Professional Corporation, Calgary, Alberta, Canada.

EXPERTS

Our consolidated financial statements as of and for each of the three years in the period ended December 31, 2004 included in this prospectus have been audited by BDO Dunwoody LLP, chartered accountants, as stated in their report appearing herein and elsewhere in this registration statement, and have been so included in reliance upon the report of such firm given upon their authority as experts in auditing and accounting.

Information included in this prospectus regarding our estimated quantities of natural gas and oil reserves were prepared by us. Our proved reserve estimates as of December 31, 2004, 2003 and 2002 included in this prospectus were prepared by Netherland, Sewell & Associates, Inc., independent petroleum engineers.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the SEC a registration statement on Form S-1 regarding the common shares. This prospectus does not contain all of the information found in the registration statement. For further information regarding us and the common shares offered by this prospectus, you may desire to review the full registration statement, including its exhibits. The registration statement, including the exhibits, may be inspected and copied at the public reference facilities maintained by the SEC at 100 F Street, N.E, Room 1580, Washington, D.C. 20549. Copies of this material can also be obtained upon written request from the Public Reference Section of the SEC at 100 F Street, N.E, Room 1580, Washington, D.C. 20549, at prescribed rates or from the SEC s web site on the Internet at http://www.sec.gov. Please call the SEC at 1-800-SEC-0330 for further information on public reference rooms.

As a result of the offering, we will file with or furnish to the SEC periodic reports and other information. These reports and other information may be inspected and copied at the public reference facilities maintained by the SEC or obtained from the SEC s website as provided above. Our website on the Internet is located at http://www.gastar.com and we expect to make our periodic reports and other information filed with or furnished to the SEC available, free of charge, through our website, as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. Information on our website or any other website is not incorporated by reference into this prospectus and does not constitute a part of this prospectus.

We intend to furnish or make available to our shareholders annual reports containing our audited financial statements prepared in accordance with U.S. GAAP. We also intend to furnish or make available to our shareholders quarterly reports containing our unaudited interim financial information, including the information required by Form 10-Q, for the first three fiscal quarters of each fiscal year.

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GASTAR EXPLORATION LTD.

INDEX TO FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Gastar Exploration Ltd.

We have audited the accompanying consolidated balance sheets of Gastar Exploration Ltd. and subsidiaries (the Company) as of December 31, 2004 and 2003 and the related consolidated statements of operations, stockholders equity and comprehensive loss and cash flows for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the Standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Gastar Exploration Ltd. and subsidiaries at December 31, 2004 and 2003 and the consolidated results of their statements of loss, stockholders equity and comprehensive loss and cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2, the Company, effective January 1, 2003, adopted SFAS No. 143 regarding asset retirement obligation recognition and SFAS No. 123 regarding accounting for stock based compensation.

/s/ BDO Dunwoody LLP

BDO Dunwoody LLP

Calgary, Alberta

March 18, 2005 (December 21, 2005 as to Notes 5, 13, 14, 22 and 25)

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GASTAR EXPLORATION LTD.

CONSOLIDATED BALANCE SHEETS

	As of September 30, 2005	As of December 31, 2004	As of December 31, 2003
	(unaudited)	(in thousands)	
Assets			
Current			
Cash	$ 8,499	$ 15,842	$ 681
Revenue receivable	4,369	1,693	
Accounts receivable	7	38	237
Due from related parties (Note 20(c))	63		
Prepaid expenses	409	307	157
Current portion of deferred charges (Note 6)	34	238	
	13,381	18,118	1,075
Deferred charges (Note 6)	5,170	3,442	400
Cash call receivable (Note 3)	1,122	6,318	1,220
Property and equipment (Note 4)	158,644	56,564	35,799
Site restoration bond			263
	$ 178,317	$ 84,442	$ 38,757
Liabilities and Shareholders Equity			
Current			
Accounts payable	$ 5,228	$ 128	$ 400
Accrued interest and debt related costs	2,201	807	
Other accrued liabilities	2,150	262	200
Accounts payable joint venture partner (Note 20(a))		601	39
Notes payable (Note 14)	12,000		
Commitments payable (Notes 22)			1,343
Current portion of contract payable (Note 7)			1,000
Current portion of convertible notes (Note 9)			1,552
	21,579	1,798	4,534
Long Term			
Accrued liability (Note 6(b))	77	77	
Drilling advances liability (Note 10)		1,002	3,008
Senior notes (Note 12)		24,840	
Senior secured notes (Note 13)	56,780		
Notes payable (Note 14)	3,000		
Subordinated unsecured notes payable (Note 11)	3,074	3,038	
Convertible notes (Note 9)	30,000	30,000	6,562
Asset retirement obligation (Note 8)	3,182	1,711	984
Liability to be settled via issuance of common shares (Note 16)	12,748		
	108,861	60,668	10,554

Shareholders Equity			
Common stock (Note 16)	90,105	45,347	38,060
Additional paid-in capital (Note 16)	6,285	4,221	425
Accumulated other comprehensive loss	(95)	(95)	(95)
Deficit	(48,418)	(27,497)	(14,721)
	47,877	21,976	23,669
	$ 178,317	$ 84,442	$ 38,757

The accompanying notes are an integral part of these consolidated financial statements.

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GASTAR EXPLORATION LTD.

CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Nine Months Ended September 30,		For the Years Ended December 31,		
	2005	**2004**	**2004**	**2003**	**2002**
	(unaudited)				
	(in thousands, except share and per share amounts)				
Revenues	$ 17,496	$ 1,688	$ 6,059	$ 1,461	$ 783
Expenses					
Depletion, depreciation and amortization	9,063	750	3,233	572	360
Impairment of natural gas and oil properties	8,697		6,306	552	377
Interest and debt related items (Note 15)	10,707	1,529	3,248	2,567	2,043
Accretion on asset retirement obligation (Note 8)	78	37	52	54	
Mineral resource properties	63	32	32	30	1
Lease operating, transportation and selling	4,024	937	2,000	712	769
General and administrative	5,997	1,916	4,023	1,909	1,933
Net loss before other items	(21,133)	(3,513)	(12,835)	(4,935)	(4,700)
Other items					
Investment income and other	87	15	56	18	17
Foreign exchange gain (loss)	125	107	3	91	84
	212	122	59	109	101
Net loss before income taxes and cumulative effect of change in accounting principle	(20,921)	(3,391)	(12,776)	(4,826)	(4,599)
Provision for income taxes (Note 21)					
Net loss before cumulative effect of change in accounting principle	(20,921)	(3,391)	(12,776)	(4,826)	(4,599)
Cumulative effect of change in accounting principle, net of tax ($nil) (Note 2(p))				(121)	
Net loss	$ (20,921)	$ (3,391)	$ (12,776)	$ (4,947)	$ (4,599)
Loss per share (Note 19)					
Net loss per share before cumulative effect of change in accounting principle (basic and diluted)	$ (0.173)	$ (0.031)	$ (0.115)	$ (0.046)	$ (0.047)
Net loss per share (basic and diluted)	$ (0.173)	$ (0.031)	$ (0.115)	$ (0.047)	$ (0.047)
Weighted average shares outstanding					

Basic and diluted	121,205,445	110,708,563	111,374,446	104,958,180	98,617,920

The accompanying notes are an integral part of these consolidated financial statements.

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GASTAR EXPLORATION LTD.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS EQUITY

	Shares Issued	Common Stock	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Deficit	Total Shareholders Equity	Comprehensive Loss
			(in thousands, except share amounts)				
Balance at December 31, 2001	**98,244,638**	**$ 22,826**	**$**	**$ 4**	**$ (5,175)**	**$ 17,655**	$
Issuance of shares	152,481	211				211	
Settlement of debentures (Note 16)	5,972,374	8,794				8,794	
Exercise of stock options for cash	1,000						
Repurchase of shares (Note 16)	(1,302,200)	(1,925)				(1,925)	
Issuance of share purchase warrants (Note 10)			425			425	
Beneficial conversion feature-convertible debentures		1,896				1,896	
Foreign currency translation loss				(27)		(27)	(27)
Net loss					(4,599)	(4,599)	(4,599)
Total comprehensive loss							$ (4,626)
Balance at December 31, 2002	**103,068,293**	**31,802**	**425**	**(23)**	**(9,774)**	**22,430**	$
Repurchase of shares (Note 16)	(1,391,500)	(2,141)				(2,141)	
Settlement of debentures (Note 16)	5,206,100	8,399				8,399	
Foreign currency translation loss				(72)		(72)	(72)
Net loss					(4,947)	(4,947)	(4,947)
Total comprehensive loss							$ (5,019)
Balance at December 31, 2003	**106,882,893**	**38,060**	**425**	**(95)**	**(14,721)**	**23,669**	$
Repurchase of shares (Note 16)	(340,000)	(894)				(894)	
Conversion of convertible debentures (Note 16)	6,847,215	8,181				8,181	
Issuance of share purchase warrants (Note 17)			2,422			2,422	
Stock based compensation			1,374			1,374	
Net loss					(12,776)	(12,776)	(12,776)
Total comprehensive loss.							$ (12,776)
Balance at December 31, 2004	**113,390,108**	**$ 45,347**	**$ 4,221**	**$ (95)**	**$ (27,497)**	**$ 21,976**	

The accompanying notes are an integral part of these consolidated financial statements.

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GASTAR EXPLORATION LTD.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS EQUITY

	Shares Issued	Common Stock	Additional Paid-in Capital	Accumulated Other Comprehensive income (Loss)	Retained Deficit	Total Shareholders Equity	Comprehensive Loss
			(in thousands, except share amounts)				
Balance at December 31, 2003	**106,882,893**	**$ 38,060**	**$ 425**	**$ (95)**	**$ (14,721)**	**$ 23,669**	**$**
Repurchase of shares	(340,000)	(894)				(894)	
Conversion of convertible debentures	6,099,999	6,710				6,710	
Shares to be issued for conversion of convertible notes	747,216	1,471				1,471	
Issuance of share purchase warrants			705			705	
Stock based compensation			458			458	
Foreign currency translation loss				(92)		(92)	(92)
Net loss					(3,391)	(3,391)	(3,391)
Total comprehensive loss							$ (3,483)
Balance at September 30, 2004	**113,390,108**	**$ 45,347**	**$ 1,588**	**$ (187)**	**$ (18,112)**	**$ 28,636**	
Balance at December 31, 2004	**113,390,108**	**$ 45,347**	**$ 4,221**	**$ (95)**	**$ (27,497)**	**$ 21,976**	**$**
Stock options exercised cash	3,721,300	707				707	
Stock issuance exercised cashless	2,214,813						
Issuance of shares	16,065,187	43,638				43,638	
Share warrants exercised, cash	207,813	413				413	
Share warrants exercised, cashless	841,224						
Stock based compensation			2,064			2,064	
Net loss					(20,921)	(20,921)	(20,921)
Total comprehensive loss							$ (20,921)
Balance at September 30, 2005	**136,440,445**	**$ 90,105**	**$ 6,285**	**$ (95)**	**$ (48,418)**	**$ 47,877**	

The accompanying notes are an integral part of these consolidated financial statements.

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GASTAR EXPLORATION LTD.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Nine Months Ended September 30,		For the Years Ended December 31,		
	2005	2004	2004	2003	2002
	(unaudited)		(in thousands)		
Cash flows from operating activities:					
Net loss	$ (20,921)	$ (3,391)	$ (12,776)	$ (4,947)	$ (4,599)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:					
Depletion, depreciation and amortization	9,063	750	3,233	572	360
Impairment of natural gas and oil properties	8,697		6,306	552	377
Amortization of deferred lease cost	204		33		
Cumulative effect of a change in accounting principle				121	
Stock compensation expense	2,064	458	1,374		
Interest and debt related items	3,758	526	2,291	1,363	1,089
Accretion expense on asset retirement obligation (Note 8)	78	37	52	54	
Other	(2)				
Changes in operating assets and liabilities:					
Accounts receivable	(3,308)	59	(1,494)	(179)	166
Prepaid expenses	(102)	(789)	(716)	(45)	(27)
Accounts payable and accrued liabilities	8,382	1,631	575	62	1,682
Foreign exchange		(91)	(5)	(80)	(36)
Net cash provided by (used in) operating activities	7,913	(810)	(1,127)	(2,527)	(988)
Cash flows from investing activities:					
Cash call receivable (Note 3)	5,196	(1,121)	(5,098)	(1,220)	
Development and purchases of oil and gas properties	(50,287)	(16,195)	(34,221)	(4,763)	(8,050)
Purchases of oil and gas properties from related parties	(30,900)				
Sale of oil and gas properties	2	3,296	3,000	8,618	
Purchase (sale) of furniture, equipment and other	(265)	(2)	(2)		4
Site restoration bond purchase (cancellation)		263	263	30	(56)
Foreign exchange			1		(25)
Net cash provided by (used in) investing activities	(76,254)	(13,759)	(36,057)	2,665	(8,127)
Cash flows from financing activities:					
Repayments of contract payable		(1,000)	(688)		(1,000)
Repayment of commitments payable		(1,343)	(1,342)		
Repayment of convertible notes payable			(100)		
Repayment of senior notes	(26,483)				
Proceeds from (repayment) of note payable				(630)	630
Proceeds from issuance of convertible notes payable			30,000		7,481

Proceeds from drilling advances					4,010
Proceeds from issuance of senior notes		15,000	25,000		
Proceeds from issuance of senior secured notes	73,000				
Proceeds from issuance of subordinated, unsecured notes payable		3,250	3,250		
Advances on convertible debenture (Note 20(b))			(39)	3,054	
Debt issue costs	(3,030)	(571)	(2,846)		(693)
Proceeds from issuance of common shares, net of share issue costs	17,511				
Repurchase of common stock		(894)	(894)	(2,141)	(1,926)
Net cash provided by financing activities	60,998	14,442	52,341	283	8,502
Increase (decrease) in cash	(7,343)	(127)	15,157	421	(613)
Foreign exchange gain on cash held in foreign currency		1	4	4	7
Cash, beginning of period	15,842	681	681	256	862
Cash, end of period	$ 8,499	$ 555	$ 15,842	$ 681	$ 256
Cash paid during the period for:					
Interest	$ 4,618	$ 513	$ 600	$ 1,272	$ 772
Income taxes	$	$	$	$	$

The accompanying notes are an integral part of these consolidated financial statements

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GASTAR EXPLORATION LTD.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Business and Basis of Presentation

These consolidated financial statements represent the consolidated statements for First Sourcenergy Wyoming, Inc. (FSW) since February 29, 2000, the date it commenced operations. During 2000, FSW completed a reverse takeover (RTO) of CopperQuest Inc., and this transaction was accounted for as a recapitalization of FSW. Effective May 16, 2000, CopperQuest Inc. changed its name to Gastar Exploration Ltd. (the Company or Gastar).

The Company s principal business activities include the selection, acquisition, exploration and development of natural gas and oil properties. The Company continues to incur losses and has significant cash flow requirements in order to continue the process of exploring and developing its oil and gas properties.

The Company and a significant shareholder of the Company, Geostar Corporation (Geostar), are partners to a signed Participation and Operating Agreement (POA). Pursuant to the terms of this POA, Geostar acquires in arms-length transactions properties from various third parties on behalf of itself and Gastar. Following successful due diligence, Gastar has the right to participate in up to a 75% interest in any Geostar properties that may be acquired under this POA on an at cost basis. As detailed in Note 20(b) Geostar has also provided a convertible debenture to the Company with the intent to provide up to CDN $25 million in funds for continued operations and to help develop the Company s oil and gas properties. Advances under the debenture were subject to Geostar s availability of funds and the approval of the requested advances by Geostar s board of directors. The funds advanced under the convertible debenture were repayable by Gastar either in cash or in shares, at prevailing market prices, at the option of the Company.

Subsequent to year end, effective January 1, 2005, Geostar and the Company terminated the convertible debenture arrangement and commenced operating the East Texas properties under a Joint Operating Agreement (JOA) which has standard industry terms for the operator (Geostar) (Note 20(c). Under the new arrangement, the Company will be required to find financing for its share of future joint venture costs.

2. Significant Accounting Policies

The consolidated financial statements of the Company (in United States (U.S.) dollars unless otherwise noted) have been prepared by management in accordance with generally accepted accounting principles in the United States (US GAAP). The preparation of consolidated financial statements in conformity with US 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. The consolidated financial statements have, in management s opinion, been properly prepared using careful judgment with reasonable limits of materiality and within the framework of the significant accounting policies summarized below:

(a) *Consolidation*

The consolidated financial statements include the accounts of the Company and the consolidated accounts of all its subsidiaries. The entities included in these consolidated accounts are 100% owned unless specified: New Energy West Corporation (NEC); 616694 Alberta Ltd.; Monterey Resources, Inc.; New Energy West (U.S.A.) Corporation; 1075191 Ontario Ltd., (OntarioCo); First Sourcenergy Wyoming, Inc. (FSW); First Source Development, Inc. (FSD); First Texas Development, Inc. (FTD); First Source Gas LP; Bossier Basin LLC; First Sourcenergy Group, Inc. (FSG); First Sourcenergy Kansas, Inc. (FSK); First Sourcenergy Victoria, Inc. (FSV); Squaw Creek, Inc. (SCI); First Appalachian Development, Inc. (FAD) and Oil and Gas Services Inc. (OGS). All significant intercompany accounts and transactions have been eliminated.

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GASTAR EXPLORATION LTD.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(b) *Furniture, Equipment and Other*

Furniture, equipment and other are carried at historical cost and are amortized over various periods ranging from three to seven years on a straight-line basis.

(c) *Oil and natural gas properties*

The Company follows the full cost method of accounting for oil and gas operations, whereby all costs of exploring for and developing oil and natural gas reserves are initially capitalized. Such costs include land acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling and overhead charges directly related to acquisition and exploration activities.

Costs capitalized, together with the costs of production equipment, are depleted and amortized on the unit-of-production method based on the estimated net proved reserves as determined by independent petroleum engineers, converting one barrel of oil to one thousand cubic feet natural gas equivalents (Mcfe) by multiplying barrels by a factor of 6. The percentage of total reserve volumes produced during the year is multiplied by the net capitalized investment plus future development costs in those reserves (the depletable base).

Costs of acquiring and evaluating unproved properties are initially excluded from depletion calculations. These unevaluated properties are assessed periodically to ascertain whether impairment has occurred. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion calculations.

Reserves, future production profiles and net cash flows are estimated by an independent professional reservoir engineering firm. While Gastar has hired a qualified reservoir engineering firm, its estimates are inherently uncertain, involve numerous assumptions that may not be realized, and predicted 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 the Company s results.

In applying the full cost method, the Company performs quarterly a ceiling test on properties whereby the net cost of oil and gas properties, net of related deferred income taxes (net cost), is limited to the sum of the estimated future net revenues from proved reserves using prices in effect at the end of the period held constant, discounted at 10%, and the lower of cost or fair value of unproven properties, adjusted for related income tax effects (ceiling). If the net cost exceeds the ceiling, an impairment loss is recognized for the amount by which the net cost exceeds the ceiling and is shown as a reduction in oil and gas properties and as additional depletion. Proceeds from a sale of oil and natural gas properties will be applied against capitalized costs, with no gain or loss recognized, unless such a sale would significantly alter the rate of depletion or amortization.

(d) *Mineral resource properties*

All exploration and related direct and indirect overhead expenditures for mineral resource properties are expensed. Capitalized acquisition costs, if any, are written off when the decision to abandon is made.

(e) *Site restoration bond*

The site restoration bond is a drilling security bond with the Minister of Mineral Resources in Australia for future site restoration on Petroleum Exploration License 238 (PEL 238). The bond was refunded in 2004 as the Company is no longer the operator. The current operator has replaced the bond with the Minister of Mineral Resources.

GASTAR EXPLORATION LTD.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(f) *Revenue recognition*

Revenues are recorded from the sale of natural gas and oil when delivery to the customer has occurred and title has transferred. This recording of revenues occurs when natural gas or oil has been delivered to a pipeline or a tank lifting has occurred.

(g) *Financial instruments*

The Company carries various forms of financial instruments. Unless otherwise indicated, it is management s opinion that the Company is not exposed to significant interest, currency or credit risks arising from these financial instruments. Unless otherwise noted, the fair values of these financial instruments approximate their carrying values.

(h) *Foreign exchange*

Foreign currency balances and non-monetary assets and liabilities are translated at the rates of exchange on the particular transaction date. Monetary assets and liabilities denominated in foreign currencies that remain outstanding at the balance sheet date are translated at period end exchange rates with resulting gains (losses) being recognized in the period. The accounts of all active subsidiaries are maintained in U.S. dollars. Translation losses recorded on investments in subsidiaries that are of a permanent nature are not tax effected.

(i) *Deferred income taxes*

The liability method of tax allocations is used, based on differences between financial reporting and tax bases of assets and liabilities. No deferred tax asset has been recorded as it is uncertain whether the Company will be able to realize this benefit.

(j) *Reporting currency*

Majority of the Company s operations are conducted by its U.S. subsidiaries in U.S. dollars. The operations outside of the U.S. are primarily oil and gas property development in Australia which are conducted in Australian dollars (AUD$). The Australian properties are in the exploration stage and there is no current production or operations in Australia. Limited operations are conducted in Canadian dollars.

Foreign operations are translated using rates in effect at the period end for the balance sheet while the income statement is translated at the average rates prevailing during the period with gains/losses being recorded in the cumulative translation account.

(k) *Loss per share*

In accordance with the provisions of SFAS No. 128, Earnings per Share (SFAS No. 128), basic earnings per share is computed on the basis of the weighted-average number of common shares outstanding during the periods. Diluted earnings per share is computed based upon the weighted-average number of common shares plus the assumed issuance of common shares for all potentially dilutive securities. Diluted per share amounts reflect the potential dilution that could occur if securities or other contracts to issue common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options and other dilutive instruments. Common shares are cancelled upon repurchase.

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GASTAR EXPLORATION LTD.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(l) *Cash and cash equivalents*

Cash and cash equivalents include short-term investments, such as money market deposits or highly liquid debt instruments, with a maturity of three months or less when purchased. We maintain our cash in bank deposit accounts, which, at times, may exceed federally insured limits. We have not experienced any losses in such accounts and believe we are not exposed to any significant risk of loss.

(m) *Stock-based compensation*

The Company reports compensation expense for stock options granted to employees, officers and directors using the fair value method. Fair values are determined using the Black-Scholes model. Compensation costs are recorded over the vesting period.

Effective January 1, 2003, the Company adopted SFAS No. 123, Accounting for Stock-Based Compensation (SFAS No. 123) which requires the Company to record compensation costs for options granted under the Company s stock option plan in accordance with the fair value method prescribed in SFAS No. 123. SFAS No. 123 was adopted for all options issued after January 1, 2003.

Prior to January 1, 2003, the Company accounted for stock options under the intrinsic value method of Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees . No compensation expense was recognized for stock options that had an exercise price equal to the market value of the underlying common stock on the date of grant.

The range of fair values of the Company s stock options granted was $0.58-$1.81 for the nine months ended September 30, 2005, $0.47-$1.42 in 2004 and $0.35-$0.70 in 2002. The fair values were determined by using the Black-Scholes option model with the following weighted average assumptions for all periods: expected dividend yield 0%, expected volatility 30% - 55%, risk free interest rate 5% and expected option term of four years.

The table below reflects the pro-forma impact of stock-based compensation on the Company s net loss and loss per share had the Company applied SFAS No, 123 to options granted prior to January 1, 2003 that vested in 2002 and subsequent periods:

	For the Nine Months Ended September 30,	For the Years Ended December 31,

	2005	2004	2004	2003	2002
	(unaudited)				
	(in thousands, except per share amounts)				
Net loss US GAAP, as reported	$ (20,921)	$ (3,391)	$ (12,776)	$ (4,947)	$ (4,599)
Cost of compensation expense using fair value	(563)	(1,597)	(1,883)	(3,743)	(6,968)
Net loss US GAAP, pro forma	$ (21,484)	$ (4,988)	$ (14,659)	$ (8,690)	$ (11,567)
Loss per share US GAAP, as reported	$ (0.173)	$ (0.031)	$ (0.115)	$ (0.047)	$ (0.047)
Loss per share US GAAP, pro forma	$ (0.177)	$ (0.045)	$ (0.132)	$ (0.083)	$ (0.117)

(n) *Deferred financing costs*

Deferred financing costs include expenses of debt financings undertaken by the Company including commissions, legal fees, value attributed to warrants or common shares issued in conjunction with a financing and other direct costs of the financing. Using the interest method, the deferred financing costs are amortized over the term of the related debt.

GASTAR EXPLORATION LTD.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(o) *Accretion on convertible notes*

Using the interest method, the equity component of the convertible notes are amortized over the term of the related debt.

(p) *Asset retirement obligation*

Effective January 1, 2003, the Company adopted SFAS No. 143, Accounting for Asset Retirement Obligations (SFAS No. 143) using a cumulative effect approach to recognize transition amounts for asset retirement obligations, asset retirement costs and accumulated depreciation. Asset retirement costs and liabilities associated with site restoration and abandonment of tangible long-lived assets are initially measured at a fair value which approximates the cost a third party would incur in performing the tasks necessary to retire such assets. The fair value is recognized in the financial statements as the present value of expected future cash flows. Subsequent to the initial measurement, the effect of the passage of time on the liability for the asset retirement obligation (accretion expense) and the amortization of the asset retirement cost are recognized in the results of operations. Upon adoption, the Company recorded a cumulative-effect-type adjustment for an increase to loss of $121,000. Additionally, the Company established an asset retirement obligation of $769,000, an increase to property and equipment of $667,000 and an increase to accumulated depletion, depreciation and amortization of $19,000.

The schedule below reflects, on a pro forma basis, the net loss, net loss per share amounts and the liability for asset retirement obligations as if SFAS No. 143 had been applied during all the periods presented.

	For the Years Ended December 31,	
	2003	2002
	(in thousands, except per share amounts)	
Net loss, as reported	$ (4,947)	$ (4,599)
Plus cumulative effect of change in accounting principle	121	
Net change in depletion, depreciation and amortization of property and equipment due to adoption of SFAS No. 143		(20)
Less accretion of asset retirement obligation		(63)
Deferred taxes		
Effect on net loss	121	(83)

Net loss, as adjusted	$ (4,826)	$ (4,682)
Basic earnings per share:		
Net loss per share, as reported	$ (0.047)	$ (0.047)
Effect on net loss	0.001	(0.001)
Net loss, as adjusted	$ (0.046)	$ (0.048)

	As of December 31, 2002, As reported	Adjustments	As of December 31, 2002, As restated
		(in thousands)	
Oil and gas properties	$ 34,457	$ 648	$ 35,105
Asset retirement obligation	$ (77)	$ (769)	$ (846)

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GASTAR EXPLORATION LTD.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(q) *Joint venture operations*

The majority of the Company s petroleum and natural gas exploration activities are conducted jointly with others. These consolidated financial statements reflect only the Company s proportionate interest in such activities.

(r) *Reclassification*

Certain information provided for the prior year has been reclassified to conform to the presentation adopted in 2005.

(s) *Goodwill*

On January 1, 2002, the Company adopted SFAS No. 142, Goodwill and Other Intangible Assets (SFAS No. 142). Under SFAS No. 142, goodwill and indefinite-lived intangible assets are no longer amortized but are reviewed annually for impairment or more frequently if impairment indicators arise. Separable intangible assets that are not deemed to have an indefinite life will continue to be amortized over their useful lives. The Company has no goodwill, so adoption of this standard had no impact on our financial position or results of operations.

(t) *Unaudited periods*

The financial information with respect to the nine months ended September 30, 2005 and 2004 is unaudited. In the opinion of management, this information contains all adjustments, consisting only of normal recurring accruals, necessary for a fair presentation of the results for the periods presented. The results of operations for interim periods are not necessarily indicative of the results of operations for the full fiscal years.

(u) *Industry segment and geographic information*

The Company operates in one industry segment, which is the exploration, development and production of natural gas and crude oil. The Company s operational activities are conducted in the United States and Australia with only the United States currently having revenue generating operating results. The identifiable assets for each country have been disclosed in Note 4.

(v) *Treasury Stock*

The Company s common shares are without par value. Treasury stock purchases are recorded at cost as a reduction to common stock. Common shares are cancelled upon repurchase.

(w) *New accounting policies*

In December of 2004, the Financial Accounting Standards Board (FASB) issued SFAS 123R Share Based Payments which addresses the accounting for transactions in which an entity exchanges its equity instruments for goods and services. It also addresses transactions in which an entity incurs liabilities in exchange for goods or services that are based on the fair value of the entity s equity instruments or that may be settled by the issuance of those equity instruments. This statement is a revision of FASB statement SFAS No. 123. This statement supersedes APB Opinion No. 25, Accounting for Stock Issued to Employees . Among other things, this statement requires a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. That cost is recognized over the period during which an employee is required to provide service in exchange for the award the requisite service period (usually the vesting period). This statement is to be applied as of the beginning of the first interim or annual period that begins after December 15, 2005, but earlier adoption

GASTAR EXPLORATION LTD.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

is encouraged. Because we have adopted SFAS 123 and recorded the fair value of stock options granted after January 1, 2003, this new standard will have minimal impact.

In December of 2004, FASB issued SFAS No. 153, Exchanges of Nonmonetary Assets An Amendment of APB Opinion No. 29 (SFAS No. 153). The guidance in APB Opinion No. 29, Accounting for Nonmonetary Transactions (APB Opinion No. 29) is based on the principle that exchanges of nonmonetary assets should be measured based on the fair value of the assets exchanged. The guidance in APB Opinion No. 29, however, included certain exceptions to that principle. This Statement amends APB Opinion No. 29 to eliminate the exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. The provisions of this Statement are effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. Earlier application is permitted for nonmonetary asset exchanges occurring in fiscal periods beginning after the date this Statement is issued. The provisions of this Statement shall be applied prospectively. The adoption of SFAS No. 153 did not have any impact on the Company s financial statements.

3. Cash Call Receivable

	Opening balance	Cash Call Advances	Amounts Spent/ Refunded	Cash Calls, ending
		(in thousands)		
Lone Oak Ranch #1 well	$ 2,344	$	$ 2,344	$
Greer #1 well	3,974	1,460	5,434	
Fridkin Kaufman #2 well		5,680	5,680	
Burong #2 well		535	422	113
Burong #3 well		535	476	59
Other prepaid cash advances		6,696	5,746	950
Balance as of September 30, 2005 (unaudited)	$ 6,318	$ 14,906	$ 20,102	$ 1,122
Fridkin Kaufman #1 well	$ 1,220	$	$ 1,220	$
Cheney #1 well		9,015	9,015	
Lone Oak Ranch #1 well		8,397	6,053	2,344
Greer #1 well		4,122	148	3,974
Balance as of December 31, 2004	$ 1,220	$ 21,534	$ 16,436	$ 6,318
Fridkin Kaufman #1 well	$	$ 5,310	$ 4,090	$ 1,220

Balance as of December 31, 2003	$	$ 5,310	$ 4,090	$ 1,220

For the years 2003 and 2004, all cash calls are paid to the operator, Geostar. Geostar invoices the Company for their proportionate share of planned authorized expenditures upon Company execution of the final drilling AFE.

Of the total cash calls paid during the nine months ended September 30, 2005, $8.2 million was paid to Geostar, and the remainder was paid to other outside parties. Geostar invoices the Company for their proportionate share of planned authorized expenditures upon the execution of the final drilling.

In the second quarter of 2005, Geostar refunded to the Company $2.1 million of unused cash call balances pursuant to the acquisition of additional properties and working interests in East Texas.

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GASTAR EXPLORATION LTD.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Property and Equipment

The amount capitalized as oil and gas properties was incurred for the purchase and development of various properties in the states of California, Montana, Texas, West Virginia and Wyoming and in New South Wales and Victoria in Australia.

The following schedule represents natural gas and oil property costs by country:

	United States	Australia	Total
		(in thousands)	
From inception to September 30, 2005 (unaudited):			
Cost	$ 185,129	$ 3,672	$ 188,801
Asset retirement	2,825	69	2,894
Impairment of natural gas and oil properties	(19,413)	(604)	(20,017)
Accumulated depletion	(13,287)		(13,287)
Net book value at September 30, 2005	155,254	3,137	158,391
Furniture, equipment and other, net	247	6	253
Total property and equipment, net	$ 155,501	$ 3,143	$ 158,644
From inception to December 31, 2004:			
Cost	$ 67,991	$ 2,629	$ 70,620
Asset retirement	1,423	79	1,502
Impairment of natural gas and oil properties	(10,716)	(604)	(11,320)
Accumulated depletion	(4,246)		(4,246)
Net book value at December 31, 2004	54,452	2,104	56,556
Furniture, equipment and other, net		8	8
Total property and equipment, net	$ 54,452	$ 2,112	$ 56,564
From inception to December 31, 2003:			
Cost	$ 35,274	$ 5,719	$ 40,993
Asset retirement	743	85	828
Impairment of natural gas and oil properties	(4,411)	(604)	(5,015)
Accumulated depletion	(1,015)		(1,015)
Net book value at December 31, 2003	30,591	5,200	35,791

Furniture, equipment and other, net		8	8
Total property and equipment, net	$ 30,591	$ 5,208	$ 35,799

Excluded from the depletion base are unproved property costs of $71.6 million at September 30, 2005, $29.8 at December 31, 2004 and $26.9 million at December 31, 2003, which consists primarily of drilling in progress costs of approximately $18.6 million at September 30, 2005, $12.9 million at December 31, 2004 and $9.8 million at December 31, 2003 and acreage acquisition costs of approximately $53.0 million at September 30, 2005, $16.9 million at December 31, 2004 and $17.1 million at December 31, 2003.

At September 30, 2005 and December 31, 2004 and 2003, the results of management s ceiling test evaluation resulted in a write down for the U.S. properties of $8.7 million, $6.3 million and $451,000, respectively. Management also determined that there was no impairment in the carrying values of the Australian properties at September 30, 2005 and December 31, 2004. There was an impairment in the carrying values of the Australian properties at December 31, 2003 of $100,000.

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GASTAR EXPLORATION LTD.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

During the first nine months of 2005, expenditures on natural gas and oil properties totaled $119.1 million. Of this total, $68.5 million was paid to Geostar in connection with the acquisition of additional leasehold and working interests in the Hilltop area of East Texas and the Powder River Basin of Wyoming and Montana. For the nine months ended September 30, 2005, natural gas and oil properties were reduced by $1.0 million upon reclassification of drilling advances and $2,000 upon sale of acreage.

During 2004 and 2003, expenditures on natural gas and oil properties totaled $34.9 million and $11.3 million, respectively. In 2004, $17.7 million was paid through the Geostar JOA, and in 2003, $5.2 million was financed with the proceeds of the convertible debentures issued to Geostar. Proceeds from the sale of assets of $3.3 million and $8.6 million during 2004 and 2003, respectively, were credited to natural gas and oil properties. Natural gas and oil properties were reduced by $2.0 million and $1.0 million during 2004 and 2003, respectively, upon reclassification of drilling advances and further adjusted by $313,000 in 2004 for a settlement.

For the nine-month period ended September 30, 2005 and the year ended 2004, $105,000 of direct travel and supplies expenses were included in natural gas and oil properties. No direct travel and supplies expenses were capitalized during 2003.

In 2004, the Company entered into a farm-in agreement pursuant to the terms of which the Company received $3.0 million in 2004 for 30% of its PEL 238 CBM rights. The joint venture partners may earn an additional 35% by spending up to AUD$7.0 million of development costs. At December 31, 2004, the joint venture partners had earned an additional 20% (i.e. a total 50% working interest) by spending an additional AUD$4.0 million. As of September 30, 2005, the joint venture partners had spent the entire AUD$7.0 million of development costs and have earned the remaining additional 15% for a total 65% working interest.

The Company also has a 75% working interest in the CBM and Mineral Sands rights in EL 4416 in the Gippsland Basin, Victoria, Australia property.

Pursuant to the terms of the earn-in joint venture agreement with a third party, the Company s interest in the Powder River Basin properties was reduced by 66%. The Company received approximately $6.9 million in 2003 in conjunction with the joint venture agreement. The Company has an overriding royalty interest in an additional 2,400 net acres in the Culp Draw and Table Mountain area of the Powder River Basin pursuant to the sale of its interest for approximately $1.7 million in cash in 2003.

The Company has, pursuant to the terms of an agreement executed in 2003 with an unrelated third party industry participant, earned a 56.25% working interest in the Company s East Texas properties. The third party retained a right to a 25% back in after payout interest in the Lone Oak Ranch #1 well, drilled per the terms of a third party agreement.

5. Geostar Acquisition

On June 17, 2005, Gastar completed the acquisition of additional leasehold and working interests from Geostar, a significant shareholder, in the Hilltop area of East Texas and in the Powder River Basin of Wyoming and Montana. The Company paid a total of $68.5 million, before estimated purchase price adjustments for the interest acquired from January 1, 2005 (Effective Date) to June 17, 2005 (Acquisition Date), consisting of $30.5 million in cash, 1,650,133 common shares valued at CDN$4.50 per share and $32.0 million in unsecured subordinated notes maturing on January 31, 2006 and bearing interest at the rate of 3.42%. The acquisition was accounted for using the purchase method, with results of operations included only from Acquisition Date. The fair value of the net assets acquired was $71.6 million, including estimated purchase price adjustments.

GASTAR EXPLORATION LTD.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

On August 11, 2005, the Company executed an agreement with Geostar whereby the Geostar $32.0 million unsecured subordinated notes were cancelled. See Note 14.

The following represents the initial carrying values of the Geostar Acquisition Properties:

	As of June 17, 2005
	(in thousands)
Natural gas property cost	$ 68,500
Purchase price adjustment	2,726
Acquisition costs	400
	$ 71,626

Of the carrying values, $8.7 million was for proved developed properties, $10.6 million was for proved undeveloped properties and $52.3 was for unproven properties.

In addition, Geostar may receive additional common shares at prevailing market prices based on look-backs at June 30, 2006 and June 30, 2007 on the East Texas assets, based on a required number of drilled wells, and net reserve additions valued at $1.50 per Mcf less attributable capital expenditures to Geostar s former ownership position on the East Texas development costs.

The following unaudited pro forma results for the year ended December 31, 2004 and the nine months ended September 30, 2005 show the effect on the Company s consolidated results of operations as if the Geostar acquisition had occurred on January 1, 2004. The pro forma results are the result of combining the statement of income of the Company with the statements of revenues and direct operating expenses for the properties acquired from Geostar adjusted for (1) the financing and share issuance directly attributable to the acquisition, (2) assumption of ARO liabilities and accretion expense for the properties acquired and (3) additional depreciation, depletion and amortization expense as a result of the Company s increased ownership in the acquired properties. The statements of revenues and direct operating expenses for the Geostar assets exclude all other historical Geostar expenses. As a result, certain estimates and judgments were made in preparing the pro forma adjustments. Further, the pro forma information includes numerous assumptions and is not necessarily indicative of future results of operations.

The unaudited pro forma financial statements should be read in conjunction with the Consolidated Financial Statements and Management s Discussion and Analysis of Financial Condition and Results of Operations of the Company discussed elsewhere in this prospectus.

	For the Nine Months September 30, 2005		For the Year Ended December 31, 2004	
	As reported	Pro Forma	As Reported	Pro Forma
	(in thousands, except per share amounts)			
Revenues	$ 17,496	$ 21,144	$ 6,059	$ 9,425
Net loss	$ (20,921)	$ (17,975)	$ (12,776)	$ (19,653)
Loss per share:				
Basic and diluted	$ (0.173)	$ (0.136)	$ (0.115)	$ (0.164)

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GASTAR EXPLORATION LTD.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. Deferred Charges

	Cost	Accumulated Amortization	Net Book Value
		(in thousands)	
Deferred Financing Costs			
Balance as of December 31, 2002	$ 1,119	$ (270)	$ 849
Additions in the year		(449)	(449)
Balance as of December 31, 2003	1,119	(719)	400
Additions in the year:			
Value assigned to warrants issued (Note a)	358	(218)	140
Cash commissions and other related expenses paid (Notes 9, 11, 12, and 13)	2,846	(215)	2,631
Balance as of December 31, 2004	4,323	(1,152)	3,171
Additions during the period (Note c)	3,030		3,030
Amortization for the period		(1,302)	(1,302)
Balance as of September 30, 2005 (unaudited)	$ 7,353	$ (2,454)	$ 4,899
Deferred Lease Costs			
Additions 2004 Gas treating agreements	$ 542		
Amortization expense	(33)		
Reclass to current portion	(238)		
Balance December 31, 2004	$ 271		
Balance December 31, 2004, net (Note b)	$ 509		
Amortization expense	(204)		
Reclass to current portion	(34)		
Balance September 30, 2005 (unaudited)	$ 271		
Total Deferred Charges September 30, 2005 (unaudited)	$ 5,170		
Total Deferred Charges December 31, 2004	$ 3,442		
Total Deferred Charges December 31, 2003	$ 400		

(a) In 2004, the Company issued 2,992,261 warrants expiring at varying dates commencing from October 13, 2007 to November 20, 2009 (Note 17) with exercise prices ranging from $2.76 to $3.87 (CDN $3.64 to $4.65) per share in conjunction with financings completed in the year. The fair value of these warrants was estimated to be $2.4 million, of which $358,000 was deferred and is being amortized over the term of the related debt and $2.1 million was netted against the respective debt. The amortization period ranges from three to five years.

All of the above warrants were valued using the Black-Scholes option pricing model based on the following assumptions: dividend yield nil; expected volatility ranging from 30% to 40%; risk free interest rate 5%; term three to five years.

(b) In 2004, FTD and First Source Texas, Inc. (FST), a wholly owned subsidiary of Geostar, entered into Gas Treating Agreements with a third party for the Fridkin-Kaufman #1 (F-K #1) and Cheney #1 wells. The primary term of the agreements are two years beginning on the first day of the month immediately following the month during which the plant becomes operational. The Company s portion of costs relating to
equipment leases and operations of the plants over the two year period are estimated to approximate $1.1 million. The Company has recorded an estimated $465,000 for its portion of installation and transportation

GASTAR EXPLORATION LTD.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

costs for the plants and has also recorded an accrued liability for an estimated $77,000 for its portion of costs relating to the demobilization of the plants. These costs are being amortized to lease operating expense over the term of the related agreement.

(c) The deferred financing costs addition of $3.0 million for the nine months ended September 30, 2005 is related to the Senior Secured Note financing for related financing costs (Note 13).

7. Contract Payable

Pursuant to the acquisition of certain properties in Australia, the Company was obligated to pay $2.0 million, due in two installments. In August 2002, the first installment of $1.0 million was paid on the contract payable pursuant to the acquisition of PEL 238 interests in New South Wales, Australia from an unrelated third party and the second installment of $1.0 million was due in February 2004. The second payment was reduced to $688,000 per a settlement agreement in 2004 (Note 22 (c)) and was paid in the first quarter of 2004.

8. Asset Retirement Obligation

Effective January 1, 2003, the Company changed its policy on accounting for liabilities associated with site restoration and abandonment of its oil and gas properties pursuant to SFAS No. 143. The undiscounted amount of expected cash flows required to settle the asset retirement obligations is estimated at $4.0 million (December 31, 2004 - $2.5 million and December 31, 2003 - $1.5 million). Of these payments, 91% are expected to be made over the next 5 years, 8% is expected to be made in years 6-10, with the remainder being paid in years 11-19.

The liability for the expected cash flows, as reflected below, has been discounted for the nine months ended September 30, 2005 and the years ended December 31, 2004 and 2003 at 6.8%, 6.8% and 7.34%, respectively.

	As of September 30, 2005	As of December 31,	
		2004	2003
	(unaudited)	(in thousands)	
Asset retirement obligation, beginning of year	$ 1,711	$ 984	$ 846
Liabilities incurred	471	166	174
Accretion expense	78	52	54
Increase (reduction) due to acquisition (sale) of working interest	922	(57)	(347)
Revision in estimated cash flows		566	257

Asset retirement obligation, end of year	$ 3,182	$ 1,711	$ 984

9. Convertible Notes

In 2002, the Company issued unsecured 12%, two year Convertible Notes, (Convertible Notes) in two offerings totaling $8.3 million. The first offering ($6.7 million) was convertible at $1.10 per share and the second ($1.6 million) at $1.97 per share. The Convertible Notes outstanding was represented by:

	As of December 31, 2003
	(in thousands)
Current portion	$ 1,552
Long term	6,562
Unamortized debt discount	167
	$ 8,281

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GASTAR EXPLORATION LTD.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Company determined there was a beneficial conversion feature regarding the Convertible Notes. The Company calculated the beneficial conversion feature regarding the Convertible Notes following the guidelines of EITF 98-5. There was a beneficial conversion feature because the market price at the date of issue was greater than the effective conversion price. The beneficial conversion feature was valued at $1.9 million and has been recorded in equity and is being amortized as interest expense using the effective interest method over the life of the Convertible Notes.

In 2004, Convertible Notes totaling $8.2 million were converted, and the Company issued the noteholders a total of 6,847,215 common shares (Note 16). Convertible Notes in the amount of $100,000 were not converted and were subsequently redeemed in the fourth quarter.

On November 12, 2004, the Company issued $30.0 million aggregate principal amount of Convertible Senior Unsecured Debentures (Convertible Senior Debentures). The Convertible Senior Debentures have a term of five years and will be due November 20, 2009 and bear interest at 9.75% per annum, payable quarterly. The Convertible Senior Debentures are convertible by the holders into common shares at a conversion price of $4.38 (CDN $5.45) per share. The debentures may be redeemed by the Company in the event that the Liquidity Event (defined as the Company receiving a no-action letter from the SEC regarding the shares to be issued upon conversion, the Company s pending U.S. Registration Statement being declared effective, or the delivery of an opinion of Company s counsel that the shares to be issued upon conversion are freely tradable) has not occurred on or prior to (i) March 10, 2005, the conversion price shall be automatically adjusted to equal $4.54, (ii) May 10, 2005, the conversion price shall be automatically adjusted to equal $4.46, and (iii) July 10, 2005, the conversion price shall be automatically adjusted to equal $4.38. Additionally, the Convertible Senior Debentures will be redeemable by the Company at any time after November 13, 2006 at a redemption price equal to par plus accrued and unpaid interest; provided that, the volume weighted average trading price of the common shares of the Company, for at least 20 trading days in any consecutive 30 day period, exceeds $6.03 (CDN $7.50).

Convertible Senior Debenture financing related costs paid to unrelated parties amounted to $1.9 million. These costs have been deferred and are being amortized over the life of the debentures. The Company also issued 259,740 broker warrants with an exercise price of $3.87 (CDN $4.65) (Note 17).

There was no beneficial conversion feature associated with the Convertible Senior Debentures.

10. Drilling Advances Liability

In 2002 the Company pre-sold working interests, to arms length third parties, in four wells for $4.0 million to be used for the planned drilling program on the Company s East Texas natural gas assets. Share purchase warrants were fully vested and non-forfeitable at the date of issuance and issued to subscribers on a pro-rata basis. Each warrant has a three year term entitling the holder to acquire one common share of Gastar at a price of $1.49 (CDN $2.35) per share or on a cashless exercise basis. Under the cashless exercise basis, the holder does not pay cash consideration at the time the warrants are exercised but agrees to surrender the required number of shares (based on the trading price as of the exercise date) to settle the amounts due on the exercise. A total of 2,005,027 warrants were issued on September 23, 2002 and expire on September 23, 2005. During the month of September 2005, the 2,005,027 common share purchase warrants were exercised and converted into common shares of the Company. Of the warrants exercised, 207,813 were exercised for cash proceeds of $413,000 (CDN $485,000) and

1,797,214 were exercised on a cashless basis. The warrants exercised on a cashless basis resulted in the issuance of 841,224 net Company common shares. The Company paid to the working interest owners an advance on production revenue equal to 10% per annum of the amount invested on a quarterly basis for the first 12 months of the investment (herein referred to as interest advances). These have been recorded as interest expense. These payments will be deducted against future working interest revenue earned by the working interest

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

owners. The $4.0 million was classified as a drilling advances liability , with 25% being credited to natural gas and oil properties when the wells were drilled. At December 31, 2003, three wells remained to be drilled. Two were drilled in 2004, and the remaining well was drilled in the first quarter of 2005.

The Company determined the fair value of the share purchase warrants relating to the private placement offering for drilling advances using the Black-Scholes option-pricing model, using weighted average assumption of a nil dividend yield, expected volatility of 30%, a risk-free interest rate of 5% and a term of one year, after the hold period. As such, the Company recorded a deferred charge of $425,000 as additional paid-in capital, which was amortized once drilling commenced and on the same basis as the release of the drilling advance. The drilling program covered four deep Bossier wells on the Company s East Texas properties.

11. Subordinated Unsecured Notes Payable

In July 2004, the Company completed a $3.25 million subordinated unsecured note financing (Unsecured Notes). The Unsecured Notes mature between April and September 2009 and bear interest at 10% per annum and are callable by the Company after two years at 108% of the principal amount. The call premium reduces to 105% after three years and 101% after four years. The subscribers were issued 232,521 warrants exercisable at prices ranging from $2.76 to $3.03 (CDN $3.64 to $4.18) expiring at varying dates between April and September 2009. The value of the warrants ($235,000) (Note 17) was deducted against the debt. Interest expense relating to the amortization of the warrants of approximately $35,000 and $24,000 was recorded for the first nine months of 2005 and the year ended 2004, respectively. Cash commissions of $196,000 were incurred, which have been capitalized and will be amortized over the term of the subordinated, unsecured notes.

12. Senior Notes

In June 2004, the Company issued $15.0 million of unsecured senior notes (Senior Notes) to a private investment company. The Senior Notes mature on July 1, 2009 and bear an annual interest rate of 15% payable semi-annually with a Company option to pay interest due before December 31, 2005 in-kind through the issuance of additional Senior Notes. The Senior Notes are callable at any time by the Company at a call premium of 104% (decreasing $^1/_2$% every six months) of the principal outstanding. Warrants representing in value 10% of the principal balance were issued in conjunction with the Senior Notes. The warrants are exercisable into an aggregate of 510,525 common shares of the Company upon payment of an exercise price of $3.23 (CDN $4.40) per common share on or before five years from date of issuance. The Company has reserved the common shares to be issued upon exercise of these warrants.

As part of the financing, the Senior Note subscriber additionally received a 2% overriding royalty interest (ORRI) in the F-K #1, Cheney #1, and two future deep wells in which Gastar participates in the East Texas Bossier project area. Gastar has a right of first refusal on any sale of the ORRI granted to the subscriber of the Senior Notes.

In October 2004, the Company issued an additional $10.0 million of Senior Notes to the same private investment company on the same terms and conditions as the June 2004 Senior Notes. In conjunction with the additional Senior Note issuance, the maturity of all Senior Notes and warrants expiry was amended from five years to three years. Thus, all Senior Notes mature and related warrants expire on October 13, 2007. With the October 2004 Senior Note issuance, additional warrants exercisable into an aggregate of 1,989,475 common shares of the Company upon payment of an exercise price of $3.63 (CDN $4.54) were issued. The Company has reserved the common shares to be issued upon exercise of these warrants.

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As part of the October 2004 Senior Note issuance, the subscriber received a small proportionate ORRI in one future deep Hilltop Bossier well in which Gastar participates in the East Texas Bossier project area. Gastar has a right of first refusal on any sale of the ORRI granted to the subscriber of the Notes.

Interest payable in 2004 in the amount of $1.5 million was paid in-kind via the issuance of additional Senior Notes. These Senior Notes have the same terms as the related Senior Notes. No additional warrants are issuable on these interest payable notes. The value of the warrants ($1.8 million) (Note 17) was deducted from the debt. Interest expense relating to the amortization of the warrants of $1.6 million for the nine months ended September 30, 2005 and $184,000 for year ended 2004 was also recorded.

Total commissions and other direct costs of $750,000 were incurred and will be amortized over the life of the Senior Notes.

In June 2005, as a condition to the issuance of $63.0 million in principal amount of senior secured notes, the Senior Notes were called and repaid in full.

13. Senior Secured Notes

On June 17, 2005, the Company issued $63.0 million in principal amount of senior secured notes (Senior Secured Notes), together with the issuance of 1,217,269 of our common shares in a private placement transaction. On September 19, 2005, the Company issued to the holders of our Senior Secured Notes an additional $10.0 million of Senior Secured Notes on substantially the same terms as the original June 2005 private placement, including the issuance of 206,354 common shares to the note holders. The Senior Secured Notes are secured by substantially all of the Company s assets, bear interest at the sum of the three-month LIBOR rate plus 6%, payable quarterly, and mature five years and one day from the date of issuance. The Senior Secured Notes are redeemable in whole or in part prior to maturity at our option at any time after the first anniversary date of issuance upon payment of the principal and accrued and unpaid interest plus a premium ranging from three to five percent of redeemed principal plus interest paid; provided that a redemption at the Company s option is not permitted following public announcement of certain pending, proposed or intended change of control transactions. The Company has the right on a quarterly basis to require the note holders to purchase up to an aggregate of $10.0 million principal amount of additional Senior Secured Notes from November 2005 to June 16, 2007. If additional Senior Secured Notes are issued, the purchasers will also be entitled to receive, for no additional consideration, additional common share on similar terms as those issued with the original Senior Secured Notes in a pro rata amount based on the additional principal amount of the Senior Secured Notes.

In connection with the sale of the Senior Secured Notes, the Company agreed to issue the purchasers for no additional consideration, additional shares in increments valued at $3.6 million (CDN $4.5 million) with respect to the $63.0 million Senior Secured Note and additional shares in increments valued at $606,000 (CDN $714,286) with respect to the $10.0 million Senior Secured Notes on each of the six, twelve and eighteen-month anniversaries of the closing date, valued on a five day weighted average trading price immediately prior to the date of issuance. The Company recorded the initial placement of $73.0 million of Senior Secured Notes and common shares based on their relative fair values with $68.8 million being recorded as Senior Secured Notes and $4.2 million being recorded for the common shares issued. The Company also recorded a liability of $12.7 million related to common shares to be issued as a debt discount to be amortized using the effective interest method and recorded $777,000 of debt discount amortization in 2005. The Company also recorded an estimated $3.0 million of direct financing costs for legal fees and fees paid to an agent and will amortize these costs over the term of the Senior Secured Notes.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The issuance of additional Senior Secured Notes is contingent upon compliance with reserves to net Senior Secured Notes debt coverage ratios and other general covenants and conditions. Under the Senior Secured Notes, the PV(10) valuation is to be based on a third party independent reserve report utilizing constant pricing based on the lower of current natural gas and oil prices, adjusted for area basis differentials, or $6.00 per Mcf of natural gas and $40.00 per barrel of oil. From the first anniversary of the issuance of the notes up to the second anniversary of the issuance of the notes, proved reserves PV(10) (1P (PV10)) to net Senior Secured Notes debt must be a minimum of 1.0:1. On the second anniversary date of the notes, the 1P PV(10) reserve ratio covenant increases to a minimum of 1.5:1 and it increases to 2.0:1 on the third anniversary date and for all test periods thereafter until maturity. Utilizing the same reserve pricing criteria above, the proved plus probable reserves PV(10) (2P PV(10)) to net Senior Secured Notes debt reserve maintenance ratio covenant must be a minimum of 1.5:1 from date of issuance of the notes up to the first anniversary date and 2.0:1 to issue additional notes. On the first anniversary date of the Senior Secured Notes, the 2P PV(10) reserve ratio maintenance covenant increases to a minimum of 2.5:1, on the second anniversary to 3.0:1 and on the third anniversary and for all test periods thereafter until maturity to 3.5:1. The Company must maintain compliance with the reserve ratio covenants at all future quarterly and annual covenant determination dates or be subject to mandatory principal redemptions under certain conditions.

The Company has provided the purchasers of the Senior Secured Notes an undertaking to file a registration statement with the United States Securities and Exchange Commission to register the common shares issued (and to be issued) in conjunction with this financing in order that the common shares are freely tradable in the U.S. by December 14, 2005. In the event that the Company s registration statement is not declared effective within 180 days of closing of the financing, the Company will incur penalties equal to 1.0% per month of the value of the common shares issued as of December 14, 2005. In addition, the Company has agreed to a potential make-whole payment to the holders of the common shares issued in conjunction with the Senior Secured Notes for any decline in price between the price as of December 14, 2005 and the date that the registration statement is declared effective or the common shares become freely tradable otherwise.

14. Geostar Subordinated Notes

On June 17, 2005, concurrently with the private placement of the Senior Secured Notes, the Company completed the acquisition of additional leasehold and working interest properties from Geostar in the Hilltop area of East Texas and in the Powder River Basin of Wyoming and Montana. The Company paid a total of $68.5 million for the interests acquired from Geostar consisting of $30.5 million in cash, 1,650,133 common shares valued at CDN$4.50 per share and $32.0 million in unsecured subordinated notes maturing January 31, 2006 (the Geostar Subordinated Notes).

On August 11, 2005, the Company executed an agreement with Geostar whereby the Geostar Subordinated Notes were cancelled. In conjunction with the cancellation of the notes, the Company agreed to issue Geostar 6,373,694 common shares valued at $17.0 million based on a per share price of CDN $3.25 and a new unsecured subordinated note for $15.0 million. The new Geostar subordinated note bears interest, payable monthly commencing February 15, 2006, at three-month LIBOR plus 4.5% and matures November 15, 2006. The note requires monthly principal payments of $1.5 million commencing February 15, 2006 and continuing for nine months thereafter with a final principal payment of $1.5 million due on November 15, 2006. The Company may elect to pay interest in kind through the issuance of additional notes with such notes maturing on January 15, 2007.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

15. Interest Expense

The following table summarizes interest expense components:

	For the Nine Months Ended September 30,		For the Years Ended December 31,		
	2005	2004	2004	2003	2002
	(unaudited)		(in thousands)		
Cash and accrued	$ 6,287	$ 1,003	$ 957	$ 1,204	$ 954
Paid in-kind			1,483		
Call premium	662				
Deferred financing cost amortization	3,758	526	808	1,363	1,089
Total	$ 10,707	$ 1,529	$ 3,248	$ 2,567	$ 2,043

16. Common Stock

Authorized

The Company s articles of incorporation allow the Company to issue an unlimited number of common shares without par value.

Share issuances

(a) On June 30, 2005, Gastar completed a private placement of 6,617,736 common shares at CDN$3.31 per share. The estimated net proceeds from this placement were $16.4 million (CDN$20.5 million), after deducting placement fees and expenses.

(b) On June 17, 2005, the Company issued 1,217,269 million common shares valued at \$3.6 million (CDN\$4.5 million at CDN\$3.69 per share) pursuant to the private placement of \$63.0 million Senior Secured Notes.

(c) On June 17, 2005, concurrent with private placement of \$63.0 million Senior Secured Notes, the Company issued 1,650,133 million common shares valued at \$6.0 million (CDN\$7.4 million at CDN\$4.50 per share) pursuant to the acquisition of additional leasehold and working interest properties in East Texas and the Powder River Basin from Geostar Corporation.

(d) On August 11, 2005, the Company issued to Geostar 6,373,694 million common shares at CDN \$3.25 per share in conjunction with partial payment of \$17.0 million of the \$32.0 million note issued for property acquisition.

(e) On September 19, 2005, the Company issued 206,354 common shares representing and aggregate value of CDN\$714,286 (\$606,000) based upon a five-day weighted average trading price of CDN \$3.4615 per share pursuant to the private placement of \$10.0 million of Senior Secured Notes.

(f) During the month of September 2005, the 2,005,027 common share purchase warrants issued in conjunction with the drilling advance were exercised and converted into common shares of the Company. Of the warrants exercised, 207,813 were exercised for cash proceeds of \$413,000 (CDN \$485,000) and 1,797,214 were exercised on a cashless basis. The warrants exercised on a cashless basis resulted in the issuance of 841,224 net Company common shares.

(g) During 2004, \$8.2 million in principal amount of 12% convertible debentures and notes were converted into an aggregate of 6,847,215 common shares of Company common stock. Of the common shares issued, 6,099,999 common shares were at a conversion price of \$1.10 and 747,216 common shares were at a conversion price of \$1.97 per share.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(h) At various times during 2002 and 2003, Company exercised its option with Geostar under the agreement covering CDN$25.0 million of floating convertible debentures to issue common shares of Gastar in full payment of amounts owed to Geostar. During 2003, a total of 5,206,100 common shares were issued at market prices ranging from $1.56 to $1.95 (CDN$2.10 to CDN$2.52). During 2002 a total of 5,972,374 common shares were issued at market prices ranging from $1.40 to $1.79 (CDN$2.20 to CDN$2.72).

Share repurchases

(a) At various times from 2002 to 2004, the Company conducted normal course issuer bids to repurchase common shares of the Company. Pursuant to this program, the Company repurchased 340,000 common shares for $894,000 in 2004, 1,391,500 common shares in 2003 for $2.1 million and 1,302,200 common shares for $1.9 million in 2002. The bid expired on August 4, 2004. The common shares were cancelled upon repurchase. The amount recorded for stock repurchase represents purchase prices paid and costs of repurchase and cancellation.

Future share issuances

In conjunction with the issuance of Senior Secured Notes, the Company agreed to issue the purchasers of the Senior Secured Notes, for no additional consideration, additional common shares in designated value increments on each of the six, twelve and eighteen-month anniversaries of closing. The additional common share value increments for the June 17 and September 19, 2005 closings are $3.6 million (CDN $4.5 million) and $606,000 (CDN $714,286), respectively, resulting in the recording of a liability of $12.7 million as of September 30, 2005. This liability will be settled through the issuance of common shares. The additional common shares to be issued shall be based on the five-day weighted average trading price immediately prior to the date of issuance. If additional Senior Secured Notes are issued, the purchasers will also be entitled to receive, for no additional consideration, additional common shares on similar terms as those issued with the original Senior Secured Notes in pro rata amount based on the additional principal amount of the Senior Secured Notes.

Under the terms of the Senior Secured Notes, the Company may not at any time issue common shares to the Senior Secured Note holders to the extent the issuance of common shares would cause the holders and/or its affiliates of our Senior Secured Notes to beneficially own more than 9.9% of our outstanding common shares. In addition, the aggregate common shares issuable to the holders of the Senior Secured Notes are limited to the maximum number that may be issued without breaching the Company s obligations under the rules and regulations of the principal market or exchange where the Company s common shares trade. In the event the issuance of commons shares to the Senior Secured Note holders reach that maximum, the issuances to holders of the Senior Secured Notes would be proportionately reduced, and the Company would be required to pay cash for such unissued shares on a formula for determining the number of shares required to be issued. In the event of a change of control or upon a sale of substantially all of the Company s assets or a reorganization or merger where the Company is not the surviving entity, the Senior Secured Note holders may require the Company to accelerate the future issuance of common shares.

At September 30, 2005, the Company has reserved 27,267,426 shares to be issued pursuant to the conversion of convertible debt (up to 6,849,315), exercise of options (17,425,850), and the exercise of warrants (2,992,261).

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

17. Warrants

The following table summarizes warrant information to purchase common shares:

	Number of Warrants	Value of Warrants (in thousands)	Warrant Price per Share Range in CDN$	Warrant Price per Share Range in US$	WA(1) Remaining Life in Years	WA(1) Exercise Price in CDN$	WA(1) Exercise Price in US$
Warrants outstanding December 31, 2002 and 2003	2,005,027	$ 425	2.35	1.49		2.35	1.49
Issued in conjunction with:							
Senior Notes (Note 12)	2,500,000	1,828	4.40 - 4.54	3.23 - 3.63	2.75	4.51	3.55
Unsecured Notes (Note 11)	232,521	235	3.64 - 4.18	2.76 - 3.03	4.36	3.76	2.80
Convertible Notes (Note 9)	259,740	359	4.65	3.87	4.92	4.65	3.87
Warrants outstanding December 31, 2004	4,997,288	$ 2,847	2.35 - 4.65	1.49 - 3.87	2.14	3.62	2.70
Exercise of warrants	2,005,027	425	2.35	1.49		2.35	1.49
Warrants outstanding September 30, 2005	2,992,261	$ 2,422	3.64 - 4.65	2.76 - 3.87	2.31	4.46	3.52

(1) WA weighted average as of the respective period end dates.

18. Stock-Based Compensation

The Company has a stock-based compensation plan that allows employees to purchase common shares of the Company. 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 four years and expire five years after the grant date. The Company can issue up to 25% of the issued and outstanding shares under this plan. The Company permits option holders to exercise their options on a cashless basis by reducing the number of shares issued under the option exercise by the option price due to the Company. The reduction in the number of shares to be issued is based on trading prices prevailing on date of exercise.

For the nine months ended September 30, 2005 and the year ended December 31, 2004, the Company recorded $2.1 million and $1.4 million, respectively, in stock-based compensation expense for stock options granted using the fair-value method. Assumptions used were volatility of 30% to 55%; a risk-free interest rate of 5%; and an expected life of four years. The 5,470,000 options issued in 2004 had a fair value on grant date ranging from $0.47 to $1.42 per option. The 585,000 options issued during the first nine months of 2005 had a fair value on grant date ranging from $0.58 to $1.81 per option.

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The following is a summary of options to purchase common shares outstanding:

	Number of Options	Option Price Per Share Range in CDN$	Option Price Per Share Range in US$	WA (1) Remaining Life in Years	WA (1) Exercise Price in CDN$	WA (1) Exercise Price in US$
Options outstanding as of December 31, 2002 and 2003	18,898,600	0.30 - 2.81	0.19 - 1.79		1.92	1.20
Options granted:						
April 20, 2004	825,000	3.70	2.75	4.33	3.70	2.75
August 4, 2004	4,645,000	3.41	2.59	4.33	3.41	2.59
Options outstanding as of December 31, 2004	24,368,600	0.30 - 3.70	0.19 - 2.75	1.93	2.26	1.52
Options exercised:						
Feb. 4 - May 26, 2005	(5,492,500)	0.30	0.19		0.30	0.19
February 9, 2005	(700,000)	0.30 - 2.76	0.19 - 1.74		1.35	0.85
March 2, 2005	(200,000)	1.66	1.09		1.66	1.09
Options cancelled/expired	(1,135,250)	0.30 - 3.41	0.19 - 2.59		1.19	0.84
Options granted:						
June 24, 2005	345,000	3.50	2.84	5.00	3.50	2.84
June 28, 2005	50,000	3.40	2.76	5.00	3.40	2.76
September 7, 2005	150,000	3.25	2.74	5.00	3.25	2.74
September 20, 2005	40,000	4.00	3.42	5.00	4.00	3.42
Options outstanding as of September 30, 2005	17,425,850	2.76 - 4.00	1.74 - 3.42	3.10	2.99	2.04

(1) WA weighted average

In conjunction with the cashless exercise of stock options in 2005, 455,387 stock options were cancelled.

Of the total options outstanding, 12,814,600 options had vested as of September 30, 2005, which have a weighted average exercise price of $2.83 and a weighted average life of 3.10 years. The expiration dates for the options outstanding are as follows:

Number of Options (in thousands)	Option Price Per Share Range in CDN$	Option Price Per Share Range in	Expiration Date

		US$	
10,974,600	2.76	1.74	July 13, 2006
700,000	2.81	1.79	April 26, 2007
750,000	3.70	2.75	April 20, 2009
4,416,250	3.41	2.59	August 4, 2009
345,000	3.50	2.84	June 24, 2010
50,000	3.40	2.76	June 28, 2010
150,000	3.25	2.74	September 7, 2010
40,000	4.00	3.42	September 20, 2010
17,425,850	2.76 - 4.00	1.74 - 3.42	

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19. Loss per share

In accordance with the provisions of SFAS No. 128, basic earnings per share is computed on the basis of the weighted-average number of common shares outstanding during the periods. Diluted earnings per share is computed based upon the weighted-average number of common shares plus the assumed issuance of common shares for all potentially dilutive securities. Diluted amounts are not shown below as such would be anti-dilutive.

	For the Nine Months Ended September 30,		For the Years Ended December 31,		
	2005	2004	2004	2003	2002
	(unaudited)				
	(in thousands, except per share and share amounts)				
Basic loss per share:					
Numerator					
Net loss before cumulative effect of change in accounting principle	$ (20,921)	$ (3,391)	$ (12,776)	$ (4,826)	$ (4,599)
Net loss	$ (20,921)	$ (3,391)	$ (12,776)	$ (4,947)	$ (4,599)
Denominator					
Common shares outstanding	121,205,445	110,708,563	111,374,446	104,958,180	98,617,920
Basic loss per share:					
Net loss per share before cumulative effect of change in accounting principle	$ (0.173)	$ (0.031)	$ (0.115)	$ (0.046)	$ (0.047)
Net loss per share applicable to all common shares	$ (0.173)	$ (0.031)	$ (0.115)	$ (0.047)	$ (0.047)
Securities excluded from denominator:					
Stock options	11,214,112	12,899,860	12,670,692	13,262,175	8,593,528
Warrants	2,965,121	1,837,555	4,615,559	1,747,070	1,132,011
Convertible debentures	6,849,315	512,653	6,493,506	4,840,712	2,875,142
	21,028,548	15,250,068	23,779,757	19,849,957	12,600,681

20. Related Party Transactions

Except as disclosed elsewhere in these financial statements, the Company had the following related party transactions:

(a) In 2001, the Company entered into a POA with Geostar. For the East Texas properties, the POA was replaced effective January 1, 2005 with a Joint Operating Agreement (JOA) as detailed in Note 20(c) below. Pursuant to the terms of the original POA, which still governs the Company s West Virginia and certain of our Australian assets, the Company has the option to participate as a working interest partner in properties in which Geostar and its subsidiaries have interests in on an at cost basis, subject to Gastar s full due diligence review prior to its participation election. Upon agreeing to participate, the Company is responsible for its proportionate share of actual costs expended by Geostar and its subsidiaries to third parties on an at cost basis. The balance of $601,000 at December 31, 2004 and $39,000 at December 31, 2003, represented amounts owed to Geostar and its subsidiaries for natural gas and oil property development. The 2003 balance was settled in 2004 by cash payment.

(b) On June 1, 2000, the Company entered into an agreement with Geostar, a significant shareholder, to settle accounts payable related to the development of natural gas and oil properties with the issuance of a floating convertible debenture for up to CDN$25.0 million. Under the agreement, Geostar would continue to provide funds for development and operations by allowing the Company to draw down on the debenture. Advances under the debenture were subject to Geostar s availability of funds and the

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

approval of the requested advances by Geostar s board of directors. The debenture was payable in cash or convertible into common shares, at prevailing market prices at the option of the Company.

(c) Effective January 1, 2005, the Company and Geostar entered into a JOA covering an Area of Mutual Interest (AMI) in East Texas, with Gastar as non operator and Geostar as operator. Under the terms of the JOA, Geostar receives overhead reimbursement equal to 12.5% of development costs for the first 10 wells drilled after the effective date, 10% of the development costs for the 11th through 20th wells and 8.5% of the developments costs for all subsequent wells. As a result, Geostar no longer charged Gastar a proportionate amount of direct salary and shared premises rent expense for Geostar employees providing administrative and technical support services to Gastar.

During 2005, Geostar billed Gastar $1.4 million, which was equal to 12.5% of projected development costs for the Greer #1 and F-K #2 wells. These costs have been capitalized to property and equipment and were paid in the second quarter. The asset purchase agreement provides for certain post closing adjustments relating to expenditures incurred on the acquired properties which may include additional agreed upon drilling overhead charges. All post closing adjustments are to be finalized by year end 2005. In conjunction with the execution of the JOA, the Company terminated the convertible debenture arrangement with Geostar and commenced operating the East Texas properties. Under the new arrangement, the Company will be required to find financing for its share of future joint venture costs.

There is a receivable with a balance of $63,000 from Geostar as of September 30, 2005, which is related to the revenue earned from the properties net of capitalized expenditures incurred during the period and net of the estimated post closing adjustments related to the Company s acquisition of additional working interests in East Texas and the Powder River Basin from Geostar. This amount, along with the final post-closing purchase price adjustments, will be settled as provided for in the Purchase and Sale Agreements between Geostar and the Company.

(d) In 2004, pursuant to the terms of the POA, Geostar billed the Company $27,000 (2003 - $369,000) for administrative overhead.

(e) In 2004, FSW recorded $1.3 million (2003 - $Nil) in general and administrative costs for administrative and technical support provided by Geostar to the Company. Commencing April 1, 2004, FSW and Geostar agreed to replace the administrative fee with a cost sharing arrangement. As a result, Geostar charged FSW a proportionate amount of direct salary and shared premises rent expense for Geostar employees providing administrative and technical support services to Gastar based on actual costs incurred. This cost sharing arrangement continued as long as Geostar is the operator of the properties. This arrangement resulted in a charge of approximately $146,000 per month for the second and third quarters of 2004 and $150,000 per month for the fourth quarter of 2004. The consolidated statements also include approximately $1,000, $115,000 and $33,000 in seismic reprocessing fees paid to Geostar at September 30, 2005, December 31, 2004 and 2003, respectively. The seismic reprocessing fees were capitalized to natural gas and oil properties.

(f) Effective January 1, 2005, the Company has agreed to hire and employ directly certain Geostar employees as members of the management team. The Company will invoice Geostar for their share of common costs, if applicable.

All related party transactions in the normal course of operations have been measured at the agreed to exchange amounts, which is the amount of consideration established and agreed to by the related parties and which is similar to those negotiated with third parties.

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21. Income Taxes

The effective tax rate of income tax varies from the statutory rate as follows:

	As of December 31,	
	2004	2003
	(in thousands, except tax rate)	
Combined effective tax rate	36.7%	36.7%
Expected income tax provision at statutory rates	$ (2,451)	$ (1,437)
Unrecorded loss carryovers	2,451	1,437
Actual income tax provision	$	$

The Company has the following approximate undeducted Canadian tax pools:

	As of December 31,	
	2004	2003
	(in thousands)	
Cumulative Canadian exploration expense	$ 801	$ 159
Cumulative Canadian development expense	$ 171	$ 107
Foreign exploration and development expense	$ 660	$ 525
Undeducted undepreciated capital cost	$ 3	$ 2
Undeducted non-capital loss carryforwards	$ 8,090	$ 6,111

If not utilized, the non-capital loss carryforwards for the above expire between 2005 and 2014.

The Company has the following approximate undeducted U.S. tax pools:

	As of December 31,	
	2004	**2003**
	(in thousands)	
Undeducted capital costs	$ 30,429	$ 28,223
Undeducted loss carryforwards	$ 45,891	$ 23,274

If not utilized, the loss carryforwards for the above expire between 2020 and 2024.

The Company has the following approximate undeducted Australian tax pools:

	As of December 31,	
	2004	**2003**
	(in thousands)	
Undeducted capital costs	$ 1,896	$ 3,781
Undeducted loss carryforwards	$ 3,121	$ 2,885

The loss carryforwards for the above do not expire.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The components of the Company s future income tax are a result of the origination and reversal of temporary differences in Canada are comprised of the following:

	As of December 31,	
	2004	2003
	(in thousands)	
Nature of temporary differences		
Capital assets	$ 600	$ 291
Share issue costs	7	13
Unused tax losses carryforward	2,970	2,243
Valuation allowance	(3,577)	(2,547)
Future income tax asset (liability)	$	$

The components of the Company s future income tax are a result of the origination and reversal of temporary differences in the US are comprised of the following:

	As of December 31,	
	2004	2003
	(in thousands)	
Nature of temporary differences		
Capital assets	$ (11,692)	$ (1,528)
Unused tax losses carryforward	16,842	8,542
Valuation allowance	(5,150)	(7,014)
Future income tax asset (liability)	$	$

The components of the Company s future income tax are a result of the origination and reversal of temporary differences in Australia are comprised of the following:

As of December 31,

	2004	2003
	(in thousands)	
Nature of temporary differences		
Capital assets	$ (108)	$ (552)
Unused tax losses carryforward	1,145	1,059
Valuation allowance	(1,037)	(507)
Future income tax asset (liability)	$	$

No future tax asset has been set up for the unutilized tax balances as their ultimate utilization of this asset is currently uncertain.

22. Commitments and Contingencies

(a) The Company and its joint venture partner were awarded by the Provincial Government of Victoria, Australia four of seven mineral exploration licenses overlying the Gippsland Basin which required the Company and its partner to spend AUD $944,000 by the second quarter of 2004. In 2004, the Company renegotiated the terms of its Gippsland Basin spending commitment and obtained an extension until April 2005. The Company proposed to the Government of Victoria, a relinquishment of approximately

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382,000 gross acres as a result of not meeting the spending commitment. This proposal was approved by the Government of Victoria. Gastar has a 75% working interest and is subsequently responsible for 75% of future expenditures.

(b) The Company had committed to a work program on PEL 238 which included drilling three vertical wells and one horizontal well by August of 2005. The Company entered into an agreement with an outside third party who completed this work program as required.

(c) The Company was a party to an arbitration claim brought by Forest Oil International Corp. (Forest) v. FSG. The arbitration has been settled and a Settlement and Release Agreement has been executed. The $1.0 million accrued at December 31, 2003 was settled via a net payment of $688,000 in 2004 (Note 7).

(d) FSG is a named party to an arbitration proceeding captioned Estate of Virgil Sparks and Oil Wells of Kentucky, Inc. v FSG and Geostar. The dispute involves historical dealings with the development of an Authority to Prospect (ATP) Area in Queensland, Australia, as well as an ancillary agreement. The formal arbitration is in discovery stages. FSG and Geostar have moved to dismiss the arbitration on the grounds of a claimed prior settlement and release agreement. FSG and Geostar are vigorously defending the arbitration, and firmly believes that its position is sound. Further, the Company s interest in ATP 560 were transferred from FSG to Conquest Exploration, Inc. (Conquest) in 2001, the result of which means that, although FSG is a named defendant, Conquest and Geostar would bear primary liability from this Arbitration action.

(e) Gastar was a party to a lawsuit, as successor, captioned Jabiru Energy Development and Innovation Pty Ltd. (Jabiru) v. FSG. The Claim has been settled by the Company, with no admission of liability by any party. In 2003, FSG paid approximately $204,000 for settlement, legal fees and other costs related to this matter.

(f) Under the terms of a third party agreement, to maintain its interests in the joint venture acreage, Gastar was obligated to provide a final payment on the leases acquired by August 15, 2004 and to spud a well by December 31, 2004 on the acquired leases to drill and test the Deep Bossier formation. At December 31, 2003, the Company had accrued approximately $600,000 for its share of the final payment on the leases. The final payment was paid in 2004 and a well was spud prior to December 31, 2004 satisfying this obligation.

(g) In 2004, FST and Navasota Resources Inc. (NRI) entered into an agreement (the 2004 Agreement) that resulted in the amendment of the previous executed August 27, 2003 Agreement. Under the terms of the 2004 Agreement, FST agreed to pay, within 5 days of the execution of the 2004 Agreement, a total of $1.1 million to two banks for the account of NRI as compensation for the amendment to the August 27, 2003 Agreement, to resolve past joint interest billing disputes and as full and final settlement of amounts owed by FST to NRI under previous agreements. As a result of the 2004 Agreement, NRI s overriding royalty interest in the leases held by FST and Gastar within the Area of Mutual Interest (AMI) under the July 7, 2000 joint operating agreement were reduced from 4.75% to 2.0%. In addition, NRI s rights to participate on an after payout basis in certain leases within the AMI was reduced from 12.5% to 5.26316% and from 20% to 10%. Gastar is obligated to fund its 75% interest in the payments required under the 2004 Agreement and Gastar s interest in the leases within the AMI will increase accordingly as a result of the reductions in NRI s interest detailed above. At December 31, 2003, the Company had accrued its proportionate share of the final payment for the agreement of $743,000. In the second quarter of 2004, the Company paid its proportionate share of the final payment pursuant to the 2004 Agreement.

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(h) During November 2004, FST and FTD entered into an agreement with a third party for natural gas transportation and purchasing services. The Company will reimburse the party for the actual cost of the taps, metering, measurement and other facilities necessary to receive the gas hereunder. The Company s estimated portion of these costs is not to exceed $97,000.

(i) As part of the Senior Note financing (Note 12), the subscribers received a 2% overriding royalty interest (ORRI) in the F-K #1, Cheney #1, and two future deep East Texas project wells in which Gastar participates. Gastar has a right of first refusal on any sale of the ORRI granted to the subscriber of the Senior Notes.

(j) The Company is subject to various regulatory and statutory requirements relating to the protection of the environment. These requirements, in addition to contractual agreements and management decisions, result in the accrual of estimated future removal and site restoration costs. These costs are initially measured at a fair value and are recognized in the consolidated financial statements as the resent value of expected future cash flows. Subsequent to the initial measurement, the effect of the passage of time on the liability for the ARO (accretion expense) and the amortization of the ARO cost are recognized in the results of operations. Costs attributable to these commitments and contingencies are expected to be incurred over an extended period of time and are to be funded mainly from the Company s cash provided by operating activities. Although the ultimate impact of these matters on net earnings cannot be determined at this time, it could be material for any quarter or year.

(k) Under the terms of employment agreements executed in March 2005 and April 2005, the Company has agreed to indemnify two executives, who have acted at the Company s request to be officers of the Company, to the extent permitted by law, against any and all damages, liabilities, costs, charges or expenses suffered by or incurred by the individuals as a result of their service. The nature of the indemnification agreements prevents the Company from making a reasonable estimate of the maximum potential amount it could be required to pay to beneficiary of such indemnification agreement. The Company has purchased various insurance policies to reduce the risks association with such indemnification. In addition to defining the terms of employment, the agreements provide for severance benefits of up to two years compensation.

(l) In 2004, the Company and certain of its subsidiaries acted as guarantors in certain senior note financing agreements totaling $25.0 million (Note 12). Additionally, in the ordinary course of business, other indemnifications may have also been provided pursuant to provisions of purchase and sale contracts, service agreements, joint venture agreements, operating agreements and leasing agreements. In these agreements, the Company has indemnified counterparties if certain events occur. These indemnification provisions vary on an agreement by agreement basis. In some cases, there are no pre-determined amounts or limits included in the indemnification provisions and the occurrence of contingent events that will trigger payment under them is difficult to predict. Therefore, the maximum potential future amount that the Company could be required to pay cannot be estimated.

(m) In 2004, the Company issued 1,989,475 warrants in conjunction with the $10.0 million Senior Note financing (Note 12). The Company obtained the required regulatory approvals and intended to issue these warrants at 110% of the market price on the closing date (i.e. the warrants are to be exercisable at $3.63 per share). It came to the Company s attention that the warrant certificate as issued reflected a price of $3.30 per share not $3.63. It was further the Company s belief and position that this was an error. The impact of issuing warrants exercisable at $3.63 per share versus $3.30 per share amounts to $657,000 of reduced proceeds on the warrant exercise. In addition, had the Company valued these warrants with an exercise price of $3.30 per share (versus the $3.63 per share as recorded), the value attributable to the warrants would increase by approximately $268,000. As of June 8, 2005, a corrected warrant certificate had been executed for the corrected price of $3.63 per share.

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(n) The Company issued a letter of credit in regards to future office rental payments in the amount of $127,000 bearing interest at a rate of 2.71%, with a maturity date of January 15, 2006.

(o) On May 3, 2005, Western Gas Resources, Lance Oil and Gas Company, Inc. and Williams Production RMT Company filed a lawsuit against First Sourcenergy Wyoming, Inc., First Sourcenergy Group, Inc. (the Company s subsidiaries) and others over a dispute that has arisen concerning a June 2002 Lease Exchange and Purchase Agreement between certain of the parties. The issue involves a certain gas gathering agreement and its applicability to some of the properties exchanged under the June 2002 Agreement. A formal response to the complaint was filed in June 2005. Discovery on this matter is just beginning, and as such it is premature to assess a probability of success in defense of this action or of the Company s exposure if liability were to be found. The Company believes that it has multiple strong defenses to this action and intends to vigorously advance its positions. While the Company does not anticipate that this action will result in a material loss to the Company, such determination is subject to measurement uncertainty. Losses, if any, will be recognized in the period of settlement.

(p) In 2004, FST and FTD entered into gas treatment agreements with a third party for the F-K #1 and Cheney #1 wells. The primary term of the agreements is 2 years beginning on the first day of the month immediately following the month during which the plant becomes operational. The following is a schedule of future lease payments (in thousands):

2005	$ 532
2006	483
2007	49
Total	$ 1,064

(q) The Company has committed to issue additional common shares pursuant to the Senior Secured Notes financing completed in the second quarter of 2005. In addition, the Company has agreed to meet certain registration requirements for the common shares issued to the holders of the Senior Secured Notes by December 14, 2005. If the Company does not meet the registration requirements, the Company will be required to pay additional interest and bear the market risk on downward price fluctuations between December 14, 2005 and the date the registration statement is effective. All of the Company s operating subsidiaries have provided a guarantee of the Company s borrowings under the Senior Secured Notes.

(r) Pursuant to the Geostar property acquisition completed on June 17, 2005, Geostar may receive additional common shares based on look-backs at June 30, 2006 and June 30, 2007 on the East Texas assets, based on a required number of drilled wells, and net reserve additions valued at $1.50 per Mcf less attributable capital expenditures to Geostar s former ownership position in the East Texas development costs.

23. Financial Instruments and Other Concentrations

The Company holds various forms of financial instruments. The nature of these instruments and the Company s operations expose the Company to interest rate risk, credit risk and fair value risk. The Company manages its exposure to these risks by operating in a manner that minimizes its exposure to the extent practical.

(a) *Interest rate risk*

The carrying value of the Company s debt approximates fair value. At September 30, 2005, the Company had approximately $88.0 million of long term debt subject to floating interest rates. Of this debt, $73.0 million of

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the Senior Secured Notes was at LIBOR plus 6% and the remaining Geostar note payable of $15.0 million was at LIBOR plus 4.5%. A 10% fluctuation in LIBOR interest rates would have an approximate $381,000 impact on annual interest expense.

(b) *Credit risk*

Substantially all of the Company s cash is held at one institution and therefore the Company is subject to concentrations of credit risk.

(c) *Fair value risk*

The fair value of the Company s current financial assets and liabilities is approximated by their carrying values due to the short-term nature of the items. The fair value of the Company s due to related party balance has not been disclosed as the amount is due to a private company and no reliable market information is available. The fair value of the Company s other long-term investments is reflected by their carrying values as the instruments have recently been negotiated and, as such, reflect prevailing market rates.

(d) *Concentration risk*

Approximately 59% of the Company s 2004 revenues are from the production at the F-K #1 well in Texas. This well commenced production on September 28, 2004.

During 2004, ETC Texas Pipeline Ltd. and Western Gas Resources, Inc. accounted for 59% and 10%, respectively, of the Company s oil and natural gas revenues. During 2003, Western Gas Resources, Inc. and Equitable Gas Company a division of Equitable Resources, Inc. accounted for 72% and 17%, respectively, of the Company s natural gas and oil revenues. Management believes that the loss of any individual purchaser would not have a long-term material adverse impact on the financial position or results of operations of the Company.

24. Statement of Cash Flows

Non-cash transactions have been disclosed in Notes 4, 5, 6, 8, 9, 10, 11, 12, 13, 14, 16, 18, 20 and 22.

25. Subsequent Events

(a) *Transaction with Chesapeake Energy Corporation*

On November 4, 2005, Gastar closed a transaction with Chesapeake Energy Corporation whereby Chesapeake:

- Acquired approximately 27.2 million newly issued common shares from the Company equal to 19.9% of its then outstanding common shares for $76.0 million (CDN$89.9 million) in cash or CDN$3.31 per share, before fees and expenses;
- Acquired a 33.33% working interest in Gastar s Deep Bossier play in the Hilltop prospect area of Leon and Robertson Counties of East Texas; and
- Formed an area of mutual interest to explore jointly in 13 counties in East Texas.

After reflecting the issue of common shares to Chesapeake, the Company has approximately 163.6 million common shares outstanding. Chesapeake has been granted registration rights for the shares issued pursuant to

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this transaction. Chesapeake also has the right, with certain exceptions, to maintain its percentage ownership on a fully diluted basis by participating in future stock issuances and has the right to an observer being present at meetings of the Board of Directors.

As part of this transaction, Chesapeake agreed to pay approximately $7.8 million, before fees and expenses, to acquire the shares described above and to pay a disproportionate amount off future drilling costs described below, in exchange for an undivided 33.33% of the Company s leasehold working interests in the Deep Bossier Hilltop prospect, less and except 160 acres surrounding each of the Company s existing well bores. Chesapeake agreed to pay 44.44% of the drilling costs through casing point in the first six wells drilled by the parties in the Hilltop prospect to a depth sufficient to test the Deep Bossier formation (an approximate depth of 19,000 feet) in order to earn its 33.33% leasehold working interest. Further, Chesapeake has agreed to provide one to two additional drilling rigs to Gastar in 2006 if needed to accelerate drilling in the Hilltop Prospect.

The transaction also provided for the formation of an area of mutual interest, or AMI, covering all of Leon, Robertson, Houston, Cherokee, Madison, Anderson, Angelina, Nacogdoches, Trinity, Polk, Shelby, San Augustine and Sabine Counties in East Texas (the AMI Area). For a period of three years from November 4, 2005, the Company will offer Chesapeake the exclusive first right to purchase up to an undivided 50% of any leasehold/working interest rights acquired by Gastar in the AMI Area on pre-determined terms. The AMI is one-way Chesapeake will not be obligated to present the Company any interests it now owns or acquires in the future in the AMI Area.

In connection with the transaction, the Company notified Chesapeake of a recent claim made by a third party that it has a right to purchase 33.33% of Gastar s interests in certain oil and gas leases located in Leon and Robertson Counties, Texas pursuant to a preferential right provision of an operating agreement dated July 7, 2000. On October 31, 2005, the third party filed a related petition for breach of contract and declaratory judgment in a legal action, as Navasota Resources, L.P. vs. First Source Texas, Inc., First Source Gas L.P., and Gastar Exploration Ltd. (Cause No. 0-05-451), in the District Court of Leon County, Texas, 12th Judicial District. The Company contends, among other things, that the claimant neither properly nor timely exercised any preferential right election it may have had with respect to the inter-dependent transactions. Accordingly, the Company intends to vigorously defend the claims.

Pursuant to the terms of the Geostar agreement, the Company will utilize a portion of the proceeds of the Chesapeake transaction to pay the Geostar note in full.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following unaudited pro forma condensed consolidated balance sheet as of September 30, 2005 shows the effect of the Chesapeake transaction as of the balance sheet date. The pro forma adjustments are (a) receipt of approximately $83.8 million in cash reduced by the $15.0 million repayment of the Geostar Note and approximately $3.4 million in transaction fees and expenses; (b) of the $83.8 million received, approximately $7.8 million was allocated to the sale of undeveloped acreage, net of approximately $340,000 in transaction fees and expenses; (c) repayment of the $15.0 million Geostar Note, $12.0 million of which was reflected in current liabilities and $3.0 million as long term debt; and (d) net equity proceeds received from the issuance of common shares.

	As of September 30, 2005		
	As Reported	Adjustments	Pro Forma
	(unaudited, in thousands)		
Assets			
Current assets	$ 13,381	$ 65,400 (a)	$ 78,781
Property and equipment	158,644	(7,428)(b)	151,216
Other	6,292		6,292
Total assets	$ 178,317	$ 57,972	$ 236,289
Liabilities and Shareholders Equity			
Current liabilities	$ 21,579	$ (12,000)(c)	$ 9,579
Long term debt	105,602	(3,000)(c)	102,602
Other liabilities	3,259		3,259
Shareholders equity	47,877	72,972 (d)	120,849
Total liabilities and shareholders equity	$ 178,317	$ 57,972	$ 236,289

(b) *Issuance of Additional Shares*

On December 19, 2005, pursuant to the Senior Secured Notes (Note 13), the Company issued to the Senior Secured Notes holders, for no additional consideration, an additional 1,082,105 common shares valued at CDN$4.1586, the five day weighted average trading price immediately prior to the date of issuance. Such shares were issued to the purchasers of the Senior Secured Notes on the six month anniversary of the original $63.0 million note issuance pursuant to subscription receipts.

26. Supplemental Oil and Gas Disclosures Unaudited

Oil and Gas Producing Activities

The following disclosures for the Company are made in accordance with SFAS No. 69, Disclosures About Oil and Gas Producing Activities (An Amendment of FASB Statements 19, 25, 33 and 39) (SFAS No. 69). Users of this information should be aware that the process of estimating quantities of proved, proved developed and proved undeveloped crude oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

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Proved reserves represent estimated quantities of natural gas and crude oil that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions existing at the time the estimates were made.

Proved developed reserves are proved reserves expected to be recovered, through wells and equipment in place and under operating methods being utilized at the time the estimates were made.

Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves are not attributed 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.

Estimates of proved developed and proved undeveloped reserves as of December 31, 2004, 2003 and 2002, were based on estimates prepared by Netherland, Sewell & Associates Inc. (NSAI) an independent petroleum reservoir engineer.

Our independent engineer is engaged by and provides their reports to the Reserve Committee of the Board of Directors. The reservoir engineer is independent and engaged to prepare the reserves reports rather than to audit reports prepared by the Company. Company management represents to the independent engineers that we have provided all relevant operating data and documents, and management reviews the reports to ensure completeness and accuracy. The Reserve Committee of the Board of Directors, which consists of J. Russell Porter, chief executive officer, and Abby Badwi, Thomas Crow, Matthew J. P. Heysel, and Richard Kapuscinski, independent directors of the Company, are charged with review of the reserve report of independent engineers on Company reserves. Members of the Reserve Committee have experience in the oil and gas exploration and production industry, but none of the members of the Reserves Committee are licensed petroleum engineers. The Reserve Committee meets with representatives of its independent petroleum engineers to review the year end engineering reports. The present members of the Reserve Committee and their related experience are set forth in Management .

Our relevant management controls over proved reserve attribution, estimation and evaluation include:

- controls over and processes for the collection and processing of all pertinent operating data and documents needed by our independent reservoir engineers to estimate our proved reserves;
- engagement of well qualified and independent reservoir engineers for review of our operating data and documents and preparation of reserve reports annually in accordance with all SEC reserve estimation guidelines; and

review by our senior management of the independent reservoir engineers reserves reports for completion and accuracy.

Market prices as of each year-end were used for future sales of natural gas, crude oil and natural gas liquids. Future operating costs, production and ad valorem taxes and capital costs were based on current costs as of each year-end, with no escalation. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures. Reserve data represent estimates only and should not be construed as being exact. Moreover, the standardized measure should

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

not be construed as the current market value of the proved oil and gas reserves or the costs that would be incurred to obtain equivalent reserves. A market value determination would include many additional factors including (a) anticipated future changes in natural gas and crude oil prices, production and development costs, (b) an allowance for return on investment, (c) the value of additional reserves, not considered proved at present, which may be recovered as a result of further exploration and development activities, and (d) other business risk.

Capitalized Costs Relating Oil and Producing Activities

The following table presents the Company s aggregate capitalized costs relating to oil producing activities and the related depreciation, depletion and amortization:

	United States	Australia	Total
		(in thousands)	
At December 31, 2004			
Proved properties	$ 41,748	$ 615	$ 42,363
Unproved properties	27,666	2,093	29,759
	69,414	2,708	72,122
Less accumulated depreciation, depletion and amortization	4,246		4,246
Less impairment allowance	10,716	604	11,320
Total	$ 54,452	$ 2,104	$ 56,556
At December 31, 2003			
Proved properties	$ 14,351	$ 604	$ 14,955
Unproved properties	21,666	5,200	26,866
	36,017	5,804	41,821
Less accumulated depreciation, depletion and amortization	1,015		1,015
Less impairment allowance	4,411	604	5,015
Total	$ 30,591	$ 5,200	$ 35,791
At December 31, 2002			
Proved properties	$ 13,816	$ 504	$ 14,320
Unproved properties	20,260	4,765	25,025

	34,076	5,269	39,345
Less accumulated depreciation, depletion and amortization	444		444
Less impairment allowance	3,959	504	4,463
Total	$ 29,673	$ 4,765	$ 34,438

Pursuant to SFAS No. 143, net capitalized cost includes related asset retirement cost of $1.5 million, $828,000 and $77,000 at December 31, 2004, 2003 and 2002, respectively.

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Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities

The acquisition, exploration and development costs disclosed in the following tables are in accordance with definitions in SFAS No. 19. Acquisition costs include costs incurred to purchase, lease or otherwise acquire property. Exploration costs include exploration expenses and additions to exploration wells, including those in progress. Development costs include additions to production facilities and equipment, as well as additions to development wells, including those in progress. The following table sets forth costs incurred related to the Company s oil and gas activities for the years ended December 31, 2004, 2003, and 2002:

Costs incurred in oil and gas-producing activities are as follows:

	United States	Australia	Total
		(in thousands)	
For the year ended December 31, 2004			
Proved property acquisition	$ 1,460	$ 2	$ 1,462
Unproved property acquisition	3,163	(288)	2,875
Exploration	27,662	195	27,857
Development	2,437		2,437
Total	$ 34,722	$ (91)	$ 34,631

	United States	Australia	Total
		(in thousands)	
For the year ended December 31, 2003			
Proved property acquisition	$ 826	$ 3	$ 829
Unproved property acquisition	3,600	100	3,700
Exploration	6,012	346	6,358
Development	458		458
Total	$ 10,896	$ 449	$ 11,345

	United States	Australia	Total

		(in thousands)	
For the period ended December 31, 2002			
Proved property acquisition	$ 1,223	$ 46	$ 1,269
Unproved property acquisition	5,895	153	6,048
Exploration	2,681	256	2,937
Development	1,780		1,780
Total	$ 11,579	$ 455	$ 12,034

Costs incurred include capitalized general and administrative costs of $6,000 in 2004 all of which were related to US Operation. No capitalized general and administrative costs were incurred in 2003 and 2002.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Costs relating to unevaluated properties which have been excluded from amortization at December 31, 2004 are as follows:

	As of December 31,				
	2004	2003	2002	2001 and prior	Total
	(in thousands)				
Property acquisition	$ (125)	$ 1,059	$ 7,853	$ 7,964	$ 16,751
Exploration	5,713	415	459	1,464	8,051
Development	874	135	734	3,136	4,879
Other capitalized costs				78	78
Total	$ 6,462	$ 1,609	$ 9,046	$ 12,642	$ 29,759

The US properties are expected to be developed over the next two to five years while the Australian properties are anticipated to be developed over the next three to seven years.

Results of Operations for Oil and Gas Producing Activities

The following table sets forth results of operations for oil and gas producing activities for the years ended December 31, 2004, 2003 and 2002:

	United States
	(in thousands)
For the year ended December 31, 2004	
Oil and gas sales	$ 6,059
Production expenses	(2,000)
Impairment of natural gas and oil properties	(6,306)
Depletion, depreciation and amortization	(3,231)
Results of producing activities	$ (5,478)
Depletion, depreciation and amortization per Mcfe	$ 2.89

For the year ended December 31, 2003		
Oil and gas sales	$	1,461
Production expenses		(712)
Impairment of natural gas and oil properties		(552)
Depletion, depreciation and amortization		(570)
Results of producing activities	$	(373)
Depletion, depreciation and amortization per Mcfe	$	1.46
For the year ended December 31, 2002		
Oil and gas sales	$	783
Production expenses		(769)
Impairment of natural gas and oil properties		(377)
Depletion, depreciation and amortization		(358)
Results of producing activities	$	(721)
Depletion, depreciation and amortization per Mcfe	$	0.87

The results of producing activities exclude interest charges and general corporate expenses and represent US activities only due to no producing operations activities in Australia to date.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Net Proved and Proved Developed Reserve Summary

The Company s proved net developed and proved undeveloped reserves are located only in the United States. The Company cautions that there are many uncertainties inherent in estimating proved reserve quantities and in projecting future production rates and the timing of development expenditures. In addition, estimates of new discoveries are more imprecise than those of properties with a production history. Accordingly, these estimates are expected to change as future information becomes available. Material revisions of reserve estimates may occur in the future; development and production of the oil and gas reserves may not occur in the periods assumed and actual prices realized and actual costs incurred may vary significantly from those used. Proved reserves represent estimated quantities of natural gas, crude oil and condensate that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions existing at the time the estimates were made. Proved developed reserves are proved reserves expected to be recovered through wells and equipment in place and under operating methods being utilized at the time the estimates were made.

The following table sets forth changes in estimated net proved and proved developed and undeveloped reserves for the years ended December 31, 2004, 2003 and 2002:

	Gas (Mmcf)	Oil (MBbl)
Changes in Proved Reserves:		
December 31, 2001	8,461	44
Extensions and discoveries	7,261	
Purchases of minerals in place	481	
Revisions of previous estimates	(634)	(15)
Production	(393)	(3)
December 31, 2002	15,176	26
Extensions and discoveries	5,067	
Sales of minerals in place	(9,082)	
Revisions of previous estimates	(2,912)	(21)
Production	(385)	(1)
December 31, 2003	7,864	4
Extensions and discoveries	14,931	4
Purchases of minerals in place	2,528	
Sales of minerals in place	(2,408)	
Revisions of previous estimates	(407)	
Production	(1,108)	(2)
December 31, 2004	21,400	6

Proved Developed and Undeveloped Reserves as of:		
December 31, 2002		
Proved developed reserves	4,650	26
Proved undeveloped reserves	10,526	
Total	15,176	26
December 31, 2003		
Proved developed reserves	1,865	4
Proved undeveloped reserves	5,999	
Total	7,864	4
December 31, 2004		
Proved developed reserves	6,179	6
Proved undeveloped reserves	15,221	
Total	21,400	6

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GASTAR EXPLORATION LTD.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The following information has been developed utilizing procedures prescribed by SFAS No. 69 and based on natural gas and crude oil reserve and production volumes estimated by the independent petroleum reservoir engineers. This information may be useful for certain comparison purposes but should not be solely relied upon in evaluating the Company or its performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the standardized measure of discounted future net cash flows be viewed as representative of the current value of the Company s oil and gas assets.

The future cash flows presented below are based on sales prices, cost rates and statutory income tax rates in existence as of the date of the projections. It is expected that material revisions to some estimates of natural gas and crude oil reserves may occur in the future, development and production of the reserves may occur in periods other than those assumed, and actual prices realized and costs incurred may vary significantly from those used. Income tax expense has been computed using expected future tax rates and giving effect to tax deductions and credits available, under current laws, and which relate to oil and gas producing activities.

Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated.

The Standardized Measure of Discounted Future Net Cash Flows relating to proved oil and gas reserves is presented below:

	United States (in thousands)
December 31, 2002:	
Future cash inflows	$ 47,305
Future production costs	(22,613)
Future development costs	(7,727)
Future income taxes	(586)
Future net cash flows	16,379
10% annual discount for estimated timing of cash flows	(5,884)
Standardized measure of discounted future cash flows	$ 10,495

December 31, 2003:	
Future cash inflows	$ 41,450
Future production costs	(21,535)
Future development costs	(8,475)
Future income taxes	
Future net cash flows	11,440
10% annual discount for estimated timing of cash flows	(3,303)
Standardized measure of discounted future cash flows	$ 8,137
December 31, 2004:	
Future cash inflows	$ 112,273
Future production costs	(38,097)
Future development costs	(39,680)
Future income taxes	
Future net cash flows	34,496
10% annual discount for estimated timing of cash flows	(8,887)
Standardized measure of discounted future cash flows	$ 25,609

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GASTAR EXPLORATION LTD.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Changes in Standardized Measure of Discounted Future Net Cash Flows

The principal sources of changes in the Standardized Measure of Future Net Cash Flows are as follows:

	United States
	(in thousands)
December 31, 2001	$ 5,120
Extensions and discoveries, less related costs	3,593
Sales of oil and gas, net of production costs	(14)
Purchases of minerals in place	478
Revisions in previous quantity estimates	(732)
Net change in income tax	(111)
Net changes in prices and production costs	2,208
Accretion of discount	480
Development costs incurred	294
Net change in estimated future development costs	(1,107)
Change in production rates (timing) - other	286
December 31, 2002	10,495
Extensions and discoveries, less related costs	5,378
Sales of oil and gas, net of production costs	(749)
Sales of minerals in place	(10,054)
Revisions in previous quantity estimates	(4,675)
Net change in income tax	111
Net changes in prices and production costs	2,129
Accretion of discount	1,273
Development costs incurred	1,713
Net change in estimated future development costs	3,689
Change in production rates (timing) - other	(1,173)
December 31, 2003	8,137
Extensions and discoveries, less related costs	21,371
Sales of oil and gas, net of production costs	(4,059)
Purchases of minerals in place	2,853
Sales of minerals in place	(2,718)
Revisions in previous quantity estimates	(1,458)
Net change in income tax	
Net changes in prices and production costs	291
Accretion of discount	864
Development costs incurred	337
Net change in estimated future development costs	1,684
Change in production rates (timing) - other	(1,693)

December 31, 2004	$	25,609

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Directors of Gastar Exploration Ltd.

We have audited the accompanying statements of revenues and direct operating expenses for certain natural gas properties (Geostar Acquisition Properties) acquired by Gastar Exploration Ltd. (the Company) from Geostar Corporation for the years ended December 31, 2004, 2003 and 2002. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these statements based on our audits.

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

The accompanying statements were prepared for the purpose of complying with the rules and regulations of the Securities and Exchange Commission as described in Note 1 to the statements and are not intended to be a complete presentation of the Company s interests in the properties described above.

In our opinion, the statements referred to above presents fairly, in all material respects, the revenues and direct operating expenses, described in Note 1, of the Geostar Acquisition Properties for the years ended December 31, 2004, 2003 and 2002 in conformity with accounting principles generally accepted in the United States of America.

/s/ BDO Dunwoody LLP
BDO Dunwoody LLP

Calgary, Alberta

August 26, 2005

GASTAR EXPLORATION LTD.

STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES

OF THE GEOSTAR ACQUISITION PROPERTIES

	For the Three Months Ended March 31,		For the Years Ended December 31,		
	2005	2004	2004	2003	2002
	(unaudited)				
	(in thousands)				
Revenues natural gas sales	$ 1,899	$ 310	$ 3,366	$ 659	$ 205
Direct operating expenses	440	261	1,600	321	231
Revenues in excess (deficit) of direct operating expenses	$ 1,459	$ 49	$ 1,766	$ 338	$ (26)

The accompanying notes are an integral part of this financial information.

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GASTAR EXPLORATION LTD.

NOTES TO STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES

OF THE GEOSTAR ACQUISITION PROPERTIES

1. Basis of Presentation

On June 17, 2005, Gastar Exploration Ltd. (the Company) entered into a purchase and sale agreement with Geostar Corporation (Geostar) acquiring additional leasehold and working interests from Geostar in the Hilltop area of East Texas and the Powder River Basin of Wyoming and Montana (the Geostar Acquisition Properties). The transaction was classified as a significant acquisition. The statement of revenues and direct operating expenses represents the acquired portion of revenues and direct operating expenses for the Geostar Acquisition Properties for the years ended December 31, 2004, 2003 and 2002 and the unaudited portion of revenues and direct operating expenses for the Geostar Acquisition Properties for the three month periods ended March 31, 2005 and 2004.

The accompanying statements of revenues and direct operating expenses were derived from Geostar s accounting records (accrual basis, full cost method of accounting for oil and gas activities, in accordance with generally accepted accounting principles). This statement varies from an income statement in that it does not show certain expenses, which were incurred in connection with the ownership of the acquired properties, such as general corporate overhead expenses and income taxes. These costs were not separately allocated to the purchased properties in the Geostar financial records and any pro forma allocation would not be reliable or an accurate estimate of what these costs would actually have been had the purchased properties been operated historically as a stand alone entity. In addition, these allocations, if made using historical corporate overhead structures would not produce allocations that would be indicative of the historical performance of the purchased properties had they been assets of the Company, due to the varying size, structure, and operations between the Company and Geostar. This statement also does not include provisions for depreciation, depletion and amortization and accretion of asset retirement obligations as such amounts would not be indicative of future costs and credit-adjusted, risk-free rates and those costs which would be incurred by the Company upon allocation of the purchase price. Accordingly, the financial statement and other information presented are not indicative of the financial condition and results of operations of the purchased properties. This information is provided to assist the reader in determining the relative impact on the Company of the Geostar Acquisition Properties on the financial results for the periods presented.

Historical information reflecting financial position, results of operations and cash flows of the Geostar Acquisition Properties are not presented, as such information is not available and not meaningful to the Geostar Acquisition Properties. Accordingly, the historical statements of revenues and direct operating expenses have been presented in lieu of the financial statements required under Rule 3-05 of the Securities and Exchange Commission Regulation S-X.

2. Supplemental Financial Information for Oil and Gas Producing Activities (Unaudited)

Supplemental natural gas and oil reserve information related to the Geostar Acquisition Properties is reported in compliance with Statement of Financial Accounting Standards No. 69, Disclosures about Oil and Gas Producing Activities (FAS 69). Net proved natural gas and oil reserves of the Geostar Acquisition Properties were prepared by Netherland, Sewell & Associates, Inc., an independent petroleum engineering firm, for Gastar Exploration Ltd. as of December 31, 2004, 2003 and 2002. The standardized measure of discounted future net cash flows related to those reserves were prepared by the Company as of and for the years ended December 31, 2004, 2003 and 2002.

Estimated Net Quantities of Oil and Gas Reserves Attributed to the Geostar Acquisition Properties. Reserve information presented below is based on the December 31, 2004 reserve report prepared by an independent petroleum engineer. The December 31, 2003 and 2002 information has been computed by adjusting the January 1, 2005 reserve report for production and known purchases.

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GASTAR EXPLORATION LTD.

NOTES TO STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES

OF THE GEOSTAR ACQUISITION PROPERTIES (Continued)

Proved reserves are estimated quantities of crude oil and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

The following table presents the estimated remaining net proved and proved developed and undeveloped natural gas and oil reserves attributable to the Geostar Acquisition Properties at December 31, 2004, 2003 and 2002, along with a summary of changes in the quantities of net remaining proved reserves during the years ended December 31, 2004, 2003 and 2002:

	Natural Gas
	(MMcf)
Changes in Proved Reserves:	
December 31, 2001	2,593
Extensions and discoveries	2,935
Purchases of minerals in place	185
Production	(120)
December 31, 2002	5,593
Extensions and discoveries	3,498
Production	(179)
December 31, 2003	8,912
Extensions and discoveries	7,395
Production	(695)
December 31, 2004	15,612
Proved Developed and Undeveloped Reserves as of:	
December 31, 2002	
Proved developed reserves	558
Proved undeveloped reserves	5,035
Total	5,593
December 31, 2003	
Proved developed reserves	393
Proved undeveloped reserves	8,519
Total	8,912

December 31, 2004	
Proved developed reserves	3,028
Proved undeveloped reserves	12,584
Total	15,612

Standardized Measures of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves. In computing the Standardized Measure, future cash inflows for the Geostar Acquisition Properties were estimated by applying period end natural gas and oil prices to the estimated future production of period end proved reserves. The natural gas prices per Mcf use for the calculations were as follows:

	As of December 31,		
	2004	**2003**	**2002**
Texas properties	$ 5.82	$ 5.97	$ 4.74
Montana and Wyoming properties	$ 5.52	$ 5.58	$ 3.12

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GASTAR EXPLORATION LTD.

NOTES TO STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES

OF THE GEOSTAR ACQUISITION PROPERTIES (Continued)

Future cash inflows were reduced by estimated future development, abandonment and production costs based on period end costs in order to arrive at net cash flow before tax. No deduction has been made for general and administrative expenses, interest, provisions for depreciation, depletion or amortization, or for taxes on income. FAS 69 requires the use of a 10% discount rate.

Standardized Measure. Information with respect to the standardized measure of discounted future net cash flows for the Geostar Acquisition Properties at December 31, 2004, 2003 and 2002 is as follows:

	United States
	(in thousands)
December 31, 2002	
Future cash inflows	$ 16,875
Future production costs	(8,140)
Future development costs	(2,881)
Future net cash flows	5,854
10% annual discount for estimated timing of cash flows	(2,184)
Standardized measure of discounted future net cash flows	$ 3,670
December 31, 2003	
Future cash inflows	$ 46,702
Future production costs	(24,378)
Future development costs	(8,860)
Future net cash flows	13,464
10% annual discount for estimated timing of cash flows	(4,253)
Standardized measure of discounted future net cash flows	$ 9,211
December 31, 2004	
Future cash inflows	$ 79,623
Future production costs	(35,161)
Future development costs	(21,695)
Future net cash flows	22,767
10% annual discount for estimated timing of cash flows	(6,603)

Standardized measure of discounted future net cash flows	$	16,164

Future cash flows are computed by applying fiscal year end prices of natural gas and oil to year-end quantities of proved natural gas and oil reserves. Future operating expenses and development costs are computed primarily by the Company s petroleum engineers by estimating the expenditures to be incurred in developing and producing the Company s proved natural gas and oil reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions.

A discount factor of 10% was used to reflect the timing of future net cash flows. The standardized measure of discounted future net cash flows is not intended to represent the replacement cost or fair value of the Geostar Acquisition Properties. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs, and a discount factor more representative of the time value of money and the risks inherent in reserve estimates of natural gas and oil producing operations.

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GASTAR EXPLORATION LTD.

NOTES TO STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES

OF THE GEOSTAR ACQUISITION PROPERTIES (Continued)

Change in Standardized Measure. Changes in the standardized measure of future net cash flows relating to proved natural gas and oil reserves are summarized below:

	United States
	(in thousands)
December 31, 2001	$ 1,268
Extensions and discoveries	1,254
Production, net of production costs	26
Purchase of minerals in place	180
Net changes in prices and production costs	638
Accretion of discount	121
Development costs incurred	111
Net changes in estimated future development costs	(417)
Change in production rates (timing) other	489
December 31, 2002	3,670
Extensions and discoveries	1,557
Production, net of production costs	(338)
Net changes in prices and production costs	1,506
Accretion of discount	455
Development costs incurred	1,268
Net changes in estimated future development costs	2,299
Change in production rates (timing) other	(1,206)
December 31, 2003	9,211
Extensions and discoveries	6,528
Production, net of production costs	(1,766)
Net changes in prices and production costs	299
Accretion of discount	948
Development costs incurred	404
Net changes in estimated future development costs	1,273
Change in production rates (timing) other	(733)
December 31, 2004	$ 16,164

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GASTAR EXPLORATION LTD.

UNAUDITED PRO FORMA FINANCIAL STATEMENTS

Introduction

On June 17, 2005, Gastar completed the acquisition of additional leasehold and working interests from Geostar, a significant shareholder, in the Hilltop area of East Texas and in the Powder River Basin of Wyoming and Montana (the Geostar Acquisition). The Company paid a total of $68.5 million, before estimated purchase price adjustments from the January 1, 2005, effective date, to June 17, 2005, acquisition date, for the interest acquired, consisting of $30.5 million in cash, 1,650,133 common shares valued at CDN $4.50 per share and $32.0 million in unsecured subordinated notes maturing on January 31, 2006 bearing interest at 3.42%. The acquisition was accounted for using the purchase method, with results of operations included in Gastar s consolidated financial statements from the acquisition date. The fair value of the net assets acquired was $71.6 million, including estimated purchase price adjustments.

The following represents the initial carrying values of the Geostar Acquisition Properties:

	As of June 17, 2005
Natural gas property cost	$ 68,500
Purchase price adjustment	2,726
Acquisition costs	400
	$ 71,626

Of the carrying values, $8.7 million was for proved developed properties, $10.6 million was for proved undeveloped properties and $52.3 was for unproven properties.

On August 11, 2005, the Company executed an agreement with Geostar whereby the Geostar $32.0 million unsecured subordinated notes were cancelled. In conjunction with the cancellation of the notes, the Company issued 6,373,694 common shares valued at $17.0 million based on a per share price of CDN$3.25 and a new unsecured subordinated note for $15.0 million. The new Geostar note bears interest, payable monthly commencing February 15, 2006, at three-month LIBOR plus 4.5%. The Geostar note requires monthly principal payments of $1.5 million commencing February 15, 2006 and continuing for nine months thereafter with the final principal payment due on November 15, 2006. Gastar may elect to pay interest in kind through the issuance of additional notes with such notes maturing on January 15, 2007.

The following unaudited pro forma results for the year ended December 31, 2004 and the nine months ended September 30, 2005, show the effect on the Company s consolidated results of operations as if the Geostar Acquisition had occurred on January 1, 2004. They are the result of combining the statement of income of the Company with the statements of revenues and direct operating expenses for the properties acquired from Geostar adjusted for (1) the financing and common share issuance directly attributable to the acquisition, (2) assumption of ARO liabilities and accretion expense for the properties acquired and (3) additional depreciation, depletion and amortization of natural gas and oil properties as a result of the Company s increased ownership in the acquired properties. The statements of revenues and direct operating expenses for the Geostar assets exclude all other historical Geostar expenses. As a result, certain estimates and judgments were made in preparing the pro forma adjustments. Further, the pro forma information includes numerous assumptions and is not necessarily indicative of future results of operations.

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GASTAR EXPLORATION LTD.

UNAUDITED PRO FORMA FINANCIAL STATEMENTS (Continued)

The pro forma financial information includes the effects of the following transactions that occurred in conjunction with the acquisition:

The issuance of $63.0 million of Senior Secured Notes and 1.2 million common shares issued in conjunction with the notes issuance on June 17, 2004;

The repayment of $25.0 million of Senior Notes as required by the Senior Secured Notes;

The issuance of 1.7 million common shares to Geostar and $32.0 million of Unsecured Subordinated Notes, which were cancelled and reissued as $15.0 of Unsecured Subordinated Notes on August 11, 2005; and

The issuance of 6.4 million common shares to Geostar as part of the renegotiation of the Geostar Unsecured Subordinated Notes on August 11, 2005.

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GASTAR EXPLORATION LTD.

UNAUDITED PRO FORMA STATEMENT OF OPERATIONS

	For the Year Ended December 31, 2004		
	As Reported	Adjustments	Pro Forma
	(in thousands, except share and per share amounts)		
REVENUES	$ 6,059	$ 3,366(a)	$ 9,425
EXPENSES:			
Depreciation, depletion and amortization	3,233	2,064(b)	5,297
Impairment of natural gas and oil properties	6,306	363(c)	6,669
Interest expense	3,248	6,188(d)	9,436
Accretion on asset retirement obligation	52	28(e)	80
Mineral resource properties	32		32
Lease operating expense	2,000	1,600(f)	3,600
General and administrative expense	4,023		4,023
Total expenses	18,894	10,243	29,137
LOSS FROM OPERATIONS	(12,835)	(6,877)	(19,712)
Investment income and other	56		56
Foreign exchange gain	3		3
LOSS BEFORE INCOME TAXES	(12,776)	(6,877)	(19,653)
Provision for income taxes			
NET LOSS	$ (12,776)	$ (6,877)	$ (19,653)
NET LOSS PER SHARE:			
Basic and diluted	$ (0.115)		$ (0.164)
WEIGHTED AVERAGE SHARES OUTSTANDING:			
Basic and diluted	111,374,446	8,370,939(g)	119,745,385

The accompanying notes are an integral part of these consolidated pro forma financial statements.

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GASTAR EXPLORATION LTD.

UNAUDITED PRO FORMA STATEMENT OF OPERATIONS

	For the Nine Months Ended September 30, 2005		
	As Reported	**Adjustments**	**Pro Forma**
	(in thousands, except share and per share amounts)		
REVENUES	17,496	$ 3,648(a)	$ 21,144
EXPENSES:			
Depreciation, depletion and amortization	9,063	2,300(b)	11,363
Impairment of natural gas and oil properties	8,697	(1,920)(c)	6,777
Interest expense	10,707	(567)(d)	10,140
Accretion on asset retirement obligation	78	28(e)	106
Mineral resource properties	63		63
Lease operating expense	4,024	861(f)	4,885
General and administrative expense	5,997		5,997
Total expenses	38,629	702	39,331
INCOME (LOSS) FROM OPERATIONS	(21,133)	2,946	(18,187)
Investment income and other	87		87
Foreign exchange gain	125		125
INCOME (LOSS) BEFORE INCOME TAXES	(20,921)	2,946	(17,975)
Provision for income taxes			
NET INCOME (LOSS)	$ (20,921)	$ 2,946	$ (17,975)
NET LOSS PER SHARE:			
Basic and diluted	$ (0.173)		$ (0.136)
WEIGHTED AVERAGE SHARES OUTSTANDING:			
Basic and diluted	121,205,445	10,813,480(g)	132,018,925

The accompanying notes are an integral part of these consolidated pro forma financial statements.

GASTAR EXPLORATION LTD.

NOTES TO THE UNAUDITED PRO FORMA FINANCIAL STATEMENTS

1. Basis of Presentation

The accompanying unaudited pro forma statements of operations present the pro forma effects of the acquisition of the Geostar Acquisition Properties and related transactions. The unaudited pro forma statements of operations for the year ended December 31, 2004 and nine months ended September 30, 2005 assume the acquisition and related transactions occurred on January 1, 2004. The acquisition has been accounted for as a purchase.

2. Pro Forma Adjustments to Statement of Operations

The following pro forma adjustments have been made to the statements of operations for the year ended December 31, 2004 and for the nine months ended September 30, 2005:

(a) To record the natural gas sale revenues for the Geostar Acquisition Properties for the year ended December 31, 2004 and for the period January 1, 2005 through the acquisition date.

(b) To record additional depreciation, depletion and amortization of $2.1 million and $2.3 million for the year ended December 31, 2004 and the nine months ended September 30, 2005, respectively, under full cost method of accounting.

(c) To record an impairment expense of natural gas and oil properties of $363,000 for the year ended December 31, 2004 and impairment benefit of $1.9 million for the nine months ended September 30, 2005.

(d) To record interest expense based on borrowings to fund the acquisition and related required debt retirement resulting in a net change in interest expense of $6.2 million and interest benefit of $567,000 for the year ended December 31, 2004 and the nine months ended September 30, 2005, respectively. The initial Senior Secured Notes issuance was estimated to be $38.0 million as of January 1, 2004 and increased by $15.0 million and $10.0 million on June 1, 2004 and October 1, 2004, respectively, to provide proceeds to repay the original issuance of Senior Notes issued on such dates. The Senior Secured Notes interest was based on the average three-month LIBOR rate of 1.51% for the year ended December 31 2004 and 2.98% for the nine months ended September 30, 2005 plus the 6% margin specified in the note agreements. The Senior Notes interest rate was 15% held constant per the respective note agreements. The $32.0 of Unsecured Subordinated Notes was deemed issued on January 1, 2004 and subsequently renegotiated in February 2004 to $15.0 million upon the issuance of $17.0 million of additional common shares. Interest on the Unsecured Subordinated Notes was initially 3.42% until renegotiated at which time the interest rate was estimated to be the three-month LIBOR rate plus the 4.5% margin specified in the note agreements.

Each 0.125% change in LIBOR interest rate would have a $98,000 annual impact on interest expense.

(e) To record accretion on the asset retirement obligation of $28,000 for the year ended December 31, 2004 and $28,000 for the nine months ended September 30, 2005.

(f) To record direct operating expenses for the Geostar Acquisition Properties for the year ended December 31, 2004 and for the period January 1, 2005 through the acquisition date.

(g) To record the increase in the average number of common shares outstanding due to (i) the issuance of 734,226 common shares, 289,826 common shares and 193,217 common shares as of January 2004, June 2004 and October 2004, respectively, (a total of 1,217,269 common shares) pursuant to the Senior Secured Notes; (ii) the issuance of 1,650,133 common shares on January 1, 2004 to Geostar; (iii) the issuance of 6,373,694 common shares to Geostar on February 25, 2004 in conjunction with the renegotiation of the Unsecured Subordinated Notes; and (iv) the issuance of additional common shares pursuant to the Senior Secured Notes of 1,217,269 as of June 2004, 1,217,269 as of December 2004 and 1,217,269 as of June 2005. The additional common shares pursuant to the Senior Secured Notes were issued utilizing the initial common share issuance price held constant.

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GASTAR EXPLORATION LTD.

NOTES TO THE UNAUDITED PRO FORMA FINANCIAL STATEMENTS (Continued)

3. Pro Forma Supplemental Financial Information for Oil and Gas Producing Activities for Geostar Acquisition Properties (unaudited)

The following pro forma table presents the estimated remaining net proved and proved developed and undeveloped natural gas and oil reserves and standardized measure attributable to Gastar as adjusted for the Geostar Acquisition Properties at December 31, 2004, 2003 and 2002, along with a summary of changes in the quantities of net remaining proved reserves and changes in standardized measure during the years ended December 31, 2004, 2003 and 2002:

	Natural Gas (MMcfe)		
	As Reported	Geostar Acquisition Properties	Pro Forma
Pro Forma Changes in Proved Reserves:			
December 31, 2001	8,725	2,593	11,318
Extensions and discoveries	7,261	2,935	10,196
Purchases of minerals in place	481	185	666
Revisions of previous estimates	(724)		(724)
Production	(411)	(120)	(531)
December 31, 2002	15,332	5,593	20,925
Extensions and discoveries	5,067	3,498	8,565
Sales of minerals in place	(9,082)		(9,082)
Revisions of previous estimates	(3,038)		(3,038)
Production	(391)	(179)	(570)
December 31, 2003	7,888	8,912	16,800
Extensions and discoveries	14,955	7,395	22,350
Purchases of minerals in place	2,528		2,528
Sales of minerals in place	(2,408)		(2,408)
Revisions of previous estimates	(407)		(407)
Production	(1,120)	(695)	(1,815)
December 31, 2004	21,436	15,612	37,048
Pro Forma Proved Developed and Undeveloped Reserves as of:			
December 31, 2002			
Proved developed reserves	4,806	558	5,364
Proved undeveloped reserves	10,526	5,035	15,561
Total	15,332	5,593	20,925

December 31, 2003			
Proved developed reserves	1,889	393	2,282
Proved undeveloped reserves	5,999	8,519	14,518
Total	7,888	8,912	16,800
December 31, 2004			
Proved developed reserves	6,215	3,028	9,243
Proved undeveloped reserves	15,221	12,584	27,805
Total	21,436	15,612	37,048

GASTAR EXPLORATION LTD.

NOTES TO THE UNAUDITED PRO FORMA FINANCIAL STATEMENTS (Continued)

Pro Forma Standardized Measure:

	United States		
	As Reported	Geostar Acquisition Properties	Pro Forma
		(in thousands)	
December 31, 2002			
Future cash inflows	$ 47,305	$ 16,875	$ 64,180
Future production costs	(22,613)	(8,140)	(30,753)
Future development costs	(7,727)	(2,881)	(10,608)
Future income taxes	(586)		(586)
Future net cash flows	16,379	5,854	22,233
10% annual discount for estimated timing of cash flows	(5,884)	(2,184)	(8,068)
Standardized measure of discounted future net cash flows	$ 10,495	$ 3,670	$ 14,165
December 31, 2003			
Future cash inflows	$ 41,450	$ 46,702	$ 88,152
Future production costs	(21,535)	(24,378)	(45,913)
Future development costs	(8,475)	(8,860)	(17,335)
Future net cash flows	11,440	13,464	24,904
10% annual discount for estimated timing of cash flows	(3,303)	(4,253)	(7,556)
Standardized measure of discounted future net cash flows	$ 8,137	$ 9,211	$ 17,348
December 31, 2004			
Future cash inflows	$ 112,273	$ 79,623	$ 191,896
Future production costs	(38,097)	(35,161)	(73,258)
Future development costs	(39,680)	(21,695)	(61,375)
Future net cash flows	34,496	22,767	57,263
10% annual discount for estimated timing of cash flows	(8,887)	(6,603)	(15,490)
Standardized measure of discounted future net cash flows	$ 25,609	$ 16,164	$ 41,773

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GASTAR EXPLORATION LTD.

NOTES TO THE UNAUDITED PRO FORMA FINANCIAL STATEMENTS (Continued)

Pro Forma Changes in Standardized Measure:

	United States		
	As Reported	Geostar Acquisition Properties	Pro Forma
		(in thousands)	
December 31, 2001	$ 5,120	$ 1,268	$ 6,388
Extensions and discoveries	3,593	1,254	4,847
Production, net of production costs	(14)	26	12
Purchase of minerals in place	478	180	658
Revisions in previous quantity estimates	(732)		(732)
Net change in income tax	(111)		(111)
Net change in prices and production costs	2,208	638	2,846
Accretion of discount	480	121	601
Development costs incurred	294	111	405
Net change in estimated future development costs	(1,107)	(417)	(1,524)
Change in estimated production rates (timing) other	286	489	775
December 31, 2002	10,495	3,670	14,165
Extensions and discoveries	5,378	1,557	6,935
Production, net of production costs	(749)	(338)	(1,087)
Sales of minerals in place	(10,054)		(10,054)
Revisions in previous quantity estimates	(4,675)		(4,675)
Net change in income tax	111		111
Net change in prices and production costs	2,129	1,506	3,635
Accretion of discount	1,273	455	1,728
Development costs incurred	1,713	1,268	2,981
Net change in estimated future development costs	3,689	2,299	5,988
Change in estimated production rates (timing) other	(1,173)	(1,206)	(2,379)
December 31, 2003	8,137	9,211	17,348
Extensions and discoveries	21,371	6,528	27,899
Production, net of production costs	(4,059)	(1,766)	(5,825)
Purchase of minerals in place	2,853		2,853
Sales of minerals in place	(2,718)		(2,718)
Revisions in previous quantity estimates	(1,458)		(1,458)
Net change in prices and production costs	291	299	590
Accretion of discount	864	948	1,812
Development costs incurred	337	404	741
Net change in estimated future development costs	1,684	1,273	2,957
Change in estimated production rates (timing) other	(1,693)	(733)	(2,426)
December 31, 2004	$ 25,609	$ 16,164	$ 41,773

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Appendix A

GLOSSARY OF NATURAL GAS AND OIL TERMS

AUD$. Australian dollars.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.

Bod. One stock tank barrel per day.

BOE. One barrel of oil equivalent determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, which approximates the relative energy content between crude natural gas and oil.

Bcf. One billion cubic feet of natural gas.

Bituminous coal. Higher rank coals.

Bwd. Barrels of water per day.

CBM. Coal bed methane.

CDN$. Canadian dollars.

Completion. The installation of permanent equipment for the production of oil or gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Developed acreage. The number of acres that are allocated or assignable to producing wells or wells capable of production.

Developed well. A well drilled within the proved area of a natural gas and oil reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole or well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceeds production expenses and taxes.

Exploration. The search for accumulations of natural gas and oil reserves by any geologic, geophysical, or other means.

Exploratory well. A well drilled to find and produce natural gas and oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas and oil in another reservoir or to extend a known reservoir.

Farmout agreement. An agreement between a leaseholder and a party willing to drill natural gas and oil wells on a leasehold property in exchange for assignments from the leaseholder of part or all of the leasehold interests. The agreement is an executory contract in that performance will take place in the future. A farmout agreement will typically (1) outline the future drilling obligations and (2) provide the framework in which the leaseholder will effect the future leasehold assignments, assuming the drilling obligations are met. The leaseholder typically reserves overriding royalty interests at the time that the leaseholder finally executes an assignment.

Field. An area consisting of single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

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Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Horizon. A geological layer or strata that may or may not contain oil or natural gas.

MBod. One thousand stock tank barrels per day.

Mcf. One thousand cubic feet of natural gas.

Mcfd. One thousand cubic feet of natural gas per day.

Mcfe. One thousand cubic feet of natural gas equivalent determined using the ratio of six Mcf of natural gas to one Bbl of oil, which approximates the relative energy content between natural gas and oil.

MBbl. One thousand stock tank barrels, or 42,000 U. S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.

MMcf. One million cubic feet of natural gas.

MMcfd. One million cubic feet of natural gas per day.

MMcfe. One million cubic feet of natural gas equivalent determined using the ratio of six Mcf of natural gas to one Bbl of oil, which approximates the relative energy content between natural gas and oil.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells.

Net smelter return. An interest in a mining property held by the vendor on the net revenues generated from the sale of metal produced by the mine.

NYMEX. The New York Mercantile Exchange, which is the primary exchange on which natural gas futures contracts are traded.

Present Value of PV(10). When used with respect to natural gas and oil reserves, the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs in effect as of the date indicated, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%.

Productive well. A well that is, or is capable of, producing hydrocarbons in sufficient quantifies such that proceeds from the sale of such production exceed production expenses and taxes.

Proved developed oil and gas reserves. Proved developed oil and gas reserves are 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. Proved developed reserves expected to be recovered from zones behind casing in existing wells.

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

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

Rank. A measure of the maturity, or age and degree of carbonization, of coals.

Recompletion. The completion for production of an existing well bore in another formation from that in which the well has been previously completed.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Royalty interest. An interest in an oil or natural gas property entitling the owner to a share of gas production free of costs of production.

Subbituminous coal. Lower rank coals.

Tcf. Trillion cubic feet of natural gas.

3-D (three dimensional) seismic. Geophysical data that depicts the subsurface strata in three dimensions. 3-D seismic data typically provides a more detailed and accurate interpretation of the subsurface strata than two dimensional seismic data.

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2-D (two dimensional) seismic. The method by which a cross-section of the earth s subsurface is created through the interpretation of reflected seismic data collected along a single source profile.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas regardless of whether such acreage contains proved reserves.

Vitrinite reflectance. Technical test of the reflectivity of a coal surface, generally associated with the rank of a coal.

Working interest. The operating interest which gives the owner the right to drill, produce and conduct operating activities on the property and a share of production. A working interest pays its share of the costs of drilling and production, as compared to an overriding royalty or royalty interest, which does not pay any costs associated with drilling or production.

Workover. Operations on a producing well to restore or increase production from the currently producing formation.

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23,085,160 Shares

Gastar Exploration Ltd.

Common Shares

Prospectus

January 4, 2006

Until January 30, 2006 (25 days after the commencement of this offering), all dealers that effect transactions in our common shares, whether or not participating in this offering, may be required to deliver a prospectus.