GASTAR EXPLORATION LTD
Form S-1/A
December 15, 2005
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As filed with the Securities and Exchange Commission on December 15, 2005

Registration No. 333-127498

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

AMENDMENT NO. 3

TO

FORM S-1

REGISTRATION STATEMENT

UNDER

THE SECURITIES ACT OF 1933

GASTAR EXPLORATION LTD.

(Exact Name of Registrant as Specified in Its Charter)

Alberta, Canada	**1311**	**38-3324634**
(State or Other Jurisdiction of Incorporation or Organization)	**(Primary Standard Industrial Classification Code Number)**	**(I.R.S. Employer Identification Number)**

1331 Lamar Street

Suite 1080

Houston, Texas 77010

(713) 739-1800

(Address, Including Zip Code, and Telephone Number, including Area Code, of Registrant s Principal Executive Offices)

J. Russell Porter, Chief Executive Officer and President

Gastar Exploration Ltd.

1331 Lamar Street, Suite 1080

Houston, Texas 77010

(713) 739-1800

(Name, Address, Including Zip Code, and Telephone Number, Including Area Code, of Agent for Service)

Copies to:

T. Mark Kelly

Vinson & Elkins L.L.P.

1001 Fannin, Suite 2300

Houston, Texas 77002

(713) 758-2222

Approximate date of commencement of proposed sale to the public: As soon as practicable after this Registration Statement becomes effective.

If any of the securities being registered on this form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, check the following box. x

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ¨

If this Form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ¨

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ¨

If delivery of the prospectus is expected to be made pursuant to Rule 434, please check the following box. ¨

The Registrant hereby amends this registration statement on such date or dates as may be necessary to delay its effective date until the Registrant shall file a further amendment that specifically states that this registration statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933 or until the registration statement shall become effective on such date as the Securities and Exchange Commission acting pursuant to said Section 8(a), may determine.

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The information in this prospectus is not complete and may be changed. We may not sell these securities until the registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell these securities and is not soliciting an offer to buy these securities in any state where the offer or sale is not permitted.

Subject to Completion, dated December 15, 2005

PROSPECTUS

23,450,000 Shares

Gastar Exploration Ltd.

Common Shares

This prospectus relates to the offer and sale, from time to time, of up to 23,450,000 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 may also trade in the United States over-the-counter market under the symbol GSREF.PK . On December 9, 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$4.05 and $3.58, respectively. On November 7, 2005, we applied for the listing of our common shares on the American Stock Exchange under the symbol GST . There is no assurance, however, that such listing will be obtained.

Investing in our common shares involves risks. Please read <u>Risk Factors</u> 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.

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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 = $0.8636, the exchange rate in effect on December 9, 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.

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 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,

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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, 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. The Board of Directors retained a qualified, independent investment banking firm to render an opinion regarding the fairness of the Geostar acquisition. The investment banking firm provided the Board of Directors with their opinion that the Geostar acquisition was fair for Gastar s shareholders from a financial perspective.

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 .

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.

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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).

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THE OFFERING

Common shares to be offered by the selling shareholders shares	23,450,000
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 may be traded in the United States over-the-counter market under the symbol GSREF.PK .

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 8,939,297 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 5,029,858 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

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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 net losses 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;

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- 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

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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

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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 and are traded in the United States over-the-counter market, 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. On November 7, 2005, we made an application to list our common shares on the American Stock Exchange under the symbol GST . There is no assurance that the listing will be effected.

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

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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 may be traded in the United States over-the-counter market under the symbol GSREF.PK . Our common shares are not listed on any U.S. or other stock exchange or quoted in any U.S. or other quotation system. 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 9, 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 9, 2005 were CDN$4.05 and $3.58, 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

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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

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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.

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

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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. The Board of Directors retained a qualified, independent investment banking firm to render an opinion regarding the fairness of the Geostar acquisition. The investment banking firm provided the Board of Directors with their opinion that the Geostar acquisition was fair for Gastar s shareholders from a financial perspective.

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.

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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

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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.

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.

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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.

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

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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, 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

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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

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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

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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. The Board of Directors retained a qualified, independent investment banking firm to render an opinion regarding the fairness of the Geostar acquisition. The investment banking firm provided the Board of Directors with their opinion that the Geostar acquisition was fair for Gastar s shareholders from a financial perspective. 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.

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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 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.

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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

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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.

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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.

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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

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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

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projected without inflation for the life of the wells included in the reserve reports. The pricing assumptions are listed below:

	2004 Report	2003 Report	2002 Report
	Gas ($/MMBtu)	Gas ($/MMBtu)	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.

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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

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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