Gastar Exploration USA, Inc.
Form S-4/A
May 21, 2008

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As filed with the Securities and Exchange Commission on May 21, 2008

Registration No. 333-150181

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

AMENDMENT No. 1

TO

FORM S-4

REGISTRATION STATEMENT

UNDER

THE SECURITIES ACT OF 1933

Gastar Exploration USA, Inc.*

(Exact name of registrant as specified in its charter)

Michigan	1311	98-0570897
(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

President

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:

Vinson & Elkins L.L.P.

First City Tower, Suite 2500

Houston, Texas 77002

(713) 758-2222

Attn: T. Mark Kelly

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

If the securities being registered on this Form are being offered in connection with the formation of a holding company and there is compliance with General Instruction G, check the following box. ¨

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(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier registration statement for the same offering. ¨

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

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

* Includes certain registrant guarantors of Gastar Exploration USA, Inc. identified on the following page.

CALCULATION OF REGISTRATION FEE

Title of Each Class of Securities To Be Registered	**Amount to be Registered**	**Proposed Maximum Offering Price Per Note (1)**	**Proposed Maximum Aggregate Offering Price (1)**	**Amount of Registration Fee (2)**
12 $^3/_4$% Senior Secured Notes due 2012	$100,000,000	100%	$100,000,000	$3,930
Guarantees of 12 $^3/_4$ % Senior Secured Notes due 2012 (3)	(4)	(4)	(4)	(5)

(1) Estimated solely for the purpose of calculating the registration fee pursuant to Rule 457(f)(2) of the rules and regulations under the Securities Act.

(2) Calculated by multiplying the aggregate offering amount by 0.00003930.

(3) See inside facing page for table of registrant guarantors.

(4) No separate consideration will be received for the guarantees.

(5) No further fee is payable pursuant to Rule 457(n) of the rules and regulations under the Securities Act.

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 which 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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ADDITIONAL GUARANTOR REGISTRANTS

EXACT NAME OF ADDITIONAL REGISTRANT AS SPECIFIED IN ITS CHARTER	STATE OR OTHER JURISDICTION OF INCORPORATION OR ORGANIZATION	PRIMARY STANDARD INDUSTRIAL CLASSIFICATION CODE NUMBER	IRS EMPLOYEE IDENTIFICATION NO.
Gaster Exploration Ltd.	Alberta, Canada	1311	98-0570897
Gastar Exploration New South Wales, Inc.	Michigan	1311	38-3234118
Gastar Exploration Victoria, Inc.	Michigan	1311	38-3604620
Gastar Exploration Texas, Inc.	Michigan	1311	38-3559023
Gastar Exploration Texas LP	Delaware	1311	30-0278927
Gastar Exploration Texas LLC	Delaware	1311	30-0278931

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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 it is not soliciting an offer to buy these securities in any state where the offer or sale is not permitted.

SUBJECT TO COMPLETION, DATED May 21, 2008

PROSPECTUS

$100,000,000

Gastar Exploration USA, Inc.

Offer to Exchange up to

$100,000,000 of 12 $^{3}/4$% Senior Secured Notes due 2012

that have been registered under the Securities Act of 1933

for

$100,000,000 of 12 $^{3}/4$% Senior Secured Notes due 2012

that have not been registered under the Securities Act of 1933

The Exchange Offer will expire at 5:00 pm, New York City time,

on , 2008, unless we extend the date

Terms of the Exchange Offer

We are offering to exchange up to $100.0 million aggregate principal amount of registered 12 $^{3}/4$% Senior Secured Notes due 2012, which we refer to as the new notes, for any and all of our $100.0 million aggregate principal amount of unregistered 12 $^{3}/4$% Senior Secured Notes due 2012, which we refer to as the old notes, that were issued on November 29, 2007. The new notes are being issued under the indenture pursuant to which we previously issued the old notes.

We will exchange all outstanding old notes that are validly tendered and not validly withdrawn prior to the expiration of the exchange offer for an equal principal amount of new notes.

The terms of the new notes are substantially identical to those of the outstanding old notes, except that the transfer restrictions and registration rights relating to the old notes do not apply to the new notes.

You may withdraw tenders of old notes at any time prior to the expiration of the exchange offer.

The exchange of new notes for old notes should not be a taxable transaction for U.S. federal income tax purposes.

We will not receive any cash proceeds from the exchange offer.

The old notes are, and the new notes will be, guaranteed by each of our existing domestic subsidiaries, future material domestic subsidiaries and by Gastar Exploration Ltd., our parent company.

This investment involves risks. Please read Risk Factors beginning on page 9 for a discussion of the risks that you should consider prior to tendering your outstanding old notes in the exchange offer.

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.

The date of this prospectus is , 2008.

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This prospectus is part of a registration statement we filed with the Securities and Exchange Commission, referred to in this prospectus as the SEC. In making your decision to participate in the exchange offer, you should rely only on the information contained in this prospectus and in the accompanying letter of transmittal. We have not authorized anyone to provide you with any other information. If you received any unauthorized information, you must not rely on it. We are not making an offer to sell these securities in any state or jurisdiction where the offer is not permitted. You should not assume that the information contained in this prospectus, or the documents incorporated by reference into this prospectus, is accurate as of any date other than the date on the front cover of this prospectus or the date of such document incorporated by reference, as the case may be.

Each broker-dealer that receives new notes for its own account pursuant to the exchange offer must acknowledge that it will deliver a prospectus in connection with any resale of such new notes. The letter of transmittal states that by so acknowledging and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an underwriter within the meaning of the Securities Act. This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer in connection with resales of new notes received in exchange for old notes where such old notes were acquired by such broker-dealer as a result of market-making activities or other trading activities. We have agreed that, for a period of 180 days after the consummation of the exchange offer, we will make this prospectus available to any broker-dealer for use in connection with any such resale. Please read Plan of Distribution .

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PROSPECTUS SUMMARY

The following summary highlights basic information about our business and this offering. It does not contain all of the information that may be important to you and your investment decision. The following summary is qualified in its entirety by the more detailed information and financial statements and notes thereto appearing elsewhere in this prospectus. Before deciding to exchange your notes, you should carefully read the entire prospectus and should consider, among other things, the matters set forth in Risk Factors . Unless the context otherwise indicates or requires, references in this prospectus to Gastar, the Company, us, our or we are to Gastar Exploration USA, Inc., Gastar Exploration Ltd., our parent company, and its consolidated subsidiaries. Throughout this prospectus, we refer to this exchange offer as the exchange offer .

Background of the Exchange Offer

On November 29, 2007, Gastar Exploration USA, Inc. (Gastar USA) a wholly owned subsidiary of Gastar Exploration Ltd., sold $100.0 million aggregate principal amount of 12 ^{3}/4% Senior Secured Notes due 2012 (the 12 ^{3}/4% Senior Secured Notes) at an issue price of 99.50%. Gastar USA is obligated to prepare and file with the Securities and Exchange Commission (the SEC) within 150 days of the issue date of the 12 ^{3}/4% Senior Secured Notes, or April 27, 2008, a registration statement to exchange the 12 ^{3}/4% Senior Secured Notes for registered, publicly tradable notes that have substantially identical terms as the 12 ^{3}/4% Senior Secured Notes. Gastar USA is to use its best efforts to cause the registration statement to be declared effective within 240 days of the issue date of the 12 ^{3}/4% Senior Secured Notes, or July 24, 2008. Gastar USA has agreed to offer new notes in exchange for the 12 ^{3}/4% Senior Secured Notes as soon as is practicable after the registration statement has become effective, unless prohibited by law or SEC policy, and to file a shelf registration statement for the resale of the 12 ^{3}/4% Senior Secured Notes if Gastar USA cannot consummate the exchange offer within 290 days of the date of the issuance of the 12 ^{3}/4% Senior Secured Notes, or September 12, 2008, and in certain other circumstances. In the event Gastar USA fails to meet its registration obligations as set forth above, Gastar USA has agreed to pay liquidated damages to the holders of the 12 ^{3}/4% Senior Secured Notes in the form of additional cash interest payments on the 12 ^{3}/4% Senior Secured Notes equal to 0.25% per annum for the first 90-day period, increasing to a maximum of 0.50% per annum for each subsequent 90-day period. We refer to this offer to exchange new notes for old notes in accordance with the terms set forth in this prospectus and the accompanying letter of transmittal as the exchange offer . You are entitled to exchange in the exchange offer your old notes for new notes.

You should read the discussion under the headings Description of the New Notes , The Exchange Offer and Description of the Notes for further information regarding the exchange offer and the new notes.

Our Company

We are a Houston, Texas-based independent natural gas and oil company engaged in the exploration, development and production of natural gas and oil in the United States and Australia. Our domestic drilling activities are focused on exploiting our multi-year inventory of drilling locations in the deep Bossier sands and Knowles Limestone plays of East Texas and in the Powder River Basin of Wyoming. Our operations in Australia are focused on the development of coal bed methane (CBM) rights in New South Wales and Victoria, Australia. We believe that our dual focus enables us to generate high initial production and long-lived producing wells with strong cash flow dynamics from our East Texas activities while also providing us with significant reserve upside through the development of our Australian resource plays. Gastar USA is a Michigan corporation. Our parent, Gastar Exploration Ltd., a Canadian corporation incorporated in Alberta (Parent), is a publicly traded company listed on the American Stock Exchange under the ticker symbol GST and on the Toronto Stock Exchange under the ticker symbol YGA with an equity market capitalization of $369 million and CDN$360 million, respectively, as of May 1, 2008.

Hilltop Area, East Texas. The majority of our activities has been in the deep Bossier play in the Hilltop area, located in East Texas approximately midway between Dallas and Houston in Leon and Robertson Counties. This exploration play has attracted some of the largest and most active operators in the U.S. Wells in this area target multiple potentially productive natural gas formations and are typically characterized by high initial production, significant decline rates and long-lived reserves.

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Our first successful operated well was spudded in 2003 and placed on production in September 2004. As of December 31, 2007, we had successfully completed 14 out of 15 deep Bossier wells and four out of four Knowles Limestone wells. During 2007, we drilled and successfully completed a total of five gross (3.0 net) Bossier wells and three gross (1.5 net) Knowles Limestone wells. For the three months ended March 31, 2008, net production from the Hilltop area averaged 20.9 MMcf per day. As of March 31, 2008, we held a total of approximately 37,500 gross (16,250 net) acres of oil and gas leaseholds in East Texas.

Southeastern Australia The exploration and development of our CBM assets in Australia has the potential for significant reserve and production growth. We own a 35% working interest in each of three petroleum exploration licenses, PEL 238, PEL 433 and PEL 434, in the Gunnedah Basin of New South Wales and a 75% working interest in an exploration license, EL 4416, in the Gippsland Basin in Victoria, Australia. These licenses include over 7.0 million gross (2.9 million net) acres. During 2008, we intend to expand our pilot production drilling program on the PEL 238 concession working with Eastern Star Gas Limited (ASX:ESG), our working interest partner and license operator. Through our planned development program in PEL 238, consisting of additional production pilot projects and core hole drilling, we intend to convert a portion of the significant resource potential into certifiable proved and probable reserves as we move towards commercial production. The certification of proved reserves and the growth of our probable reserves is necessary to support the development of infrastructure to service growing natural gas demand in New South Wales. Contracts for the construction of this infrastructure, as well as gas sales or use contracts, are not expected until late 2008 and will be required before recognition of proved reserves in PEL 238 under SEC guidelines. Eastern Star Gas Limited owns a 65% interest in PEL 238. On May 1, 2008, Eastern Star Gas Limited had an equity market capitalization of approximately USD $350 million.

Powder River Basin, Wyoming and Montana We own an approximate 40% average working interest in approximately 55,000 gross (21,900 net) acres in the Powder River Basin of Wyoming and Montana. The Powder River Basin has been an important natural gas producing area for nearly 100 years. Generally, CBM wells are shallow and less costly than conventional natural gas wells. Our primary areas of activity in the Powder River Basin are the Squaw Creek, Ring of Fire and adjacent fields, all of which are located north of Gillette, Wyoming in an active drilling area.

During 2007, we participated in the drilling of approximately 27 (12.5 net) CBM wells. As of December 31, 2007, we had an interest in 283 gross (125.2 net) productive CBM wells producing in the Basin. For the year ended December 31, 2007, our average net production from our CBM properties in the Powder River Basin was approximately 5.1 MMcf per day. We anticipate continuing our recompletion and drilling program in 2008. Our activity level will be influenced by regional natural gas prices, which remained lower than its historic prices relative to Gulf Coast Henry Hub natural gas prices during late 2007. Regional prices in early 2008 have rebounded to, or above, historic price levels. For the three months ended March 31, 2008, our average net production from our CBM properties in the Powder River Basin was approximately 5.6 MMcf per day.

Netherland Sewell & Associates, Inc. (NSA), our independent petroleum engineers, has estimated our total domestic proved reserves as of December 31, 2007, to be 54.9 Bcfe under SEC definition and guidelines, consisting almost entirely of natural gas.

Our executive offices are located at 1331 Lamar Street, Suite 1080, Houston, Texas 77010. Our telephone number is (713) 739-1800, and our website address is *http://www.gastar.com.* Information on our website does not constitute part of this prospectus.

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The Exchange Offer

On November 29, 2007, we completed a private offering of $100.0 million in aggregate principal of the old notes. As part of this private offering, we entered into a registration rights agreement with the initial purchasers of the old notes in which we agreed, among other things, to deliver this prospectus to you and to use our best efforts to complete the exchange offer. The following is a summary of the exchange offer.

Old Notes	12 $^{3}/4$ Senior Secured Notes due 2012, which were issued on November 29, 2007.
New Notes	12 $^{3}/4$ Senior Secured Notes due 2012. The terms of the new notes are substantially identical to those terms of the outstanding old notes, except that the transfer restrictions and registration rights relating to the old notes do not apply to the new notes.
Exchange Offer	We are offering to exchange up to $100.0 million aggregate principal amount of our new notes that have been registered under the Securities Act of 1933, as amended (the Securities Act), for an equal amount of our outstanding old notes that have not been registered under the Securities Act to satisfy our obligations under the registration rights agreement. The new notes will evidence the same debt as the old notes and will be issued under and will be entitled to the benefits of the same indenture that governs the old notes. Holders of the old notes do not have any appraisal or dissenter rights in connection with the exchange offer. Because the new notes will be registered, the new notes will not be subject to transfer restrictions, and holders of old notes that have tendered and had their old notes accepted in the exchange offer will have no registration rights.
Expiration Date	The exchange offer will expire at 5:00 p.m., New York City time, on , 2008, unless we decide to extend it.
Procedures for Tendering Old Notes	All of the old notes are held in book-entry form through the facilities of The Depository Trust Company, or DTC. To participate in the exchange offer, you must follow the automatic tender offer program, or ATOP, procedures established by DTC for tendering notes held in book-entry form. The ATOP procedures require that the exchange agent receive, prior to the expiration date of the exchange offer, a computer-generated message known as an agent s message that is transmitted through ATOP and that DTC confirm that DTC has received instructions to exchange your notes and you agree to be bound by the terms of the letter of transmittal in Annex A hereto. For more details, please read The Exchange Offer Terms of the Exchange and The Exchange Offer Procedures for Tendering .

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Guaranteed Delivery Procedures	None.
Withdrawal; Non-Acceptance	You may withdraw your tender of old notes at any time prior to the expiration date. To withdraw, you must submit a notice of withdrawal to the exchange agent using ATOP procedures before 5:00 p.m., New York City time, on the expiration date of the exchange offer. Please read The Exchange Offer Withdrawal Rights .
U.S. Federal Income Tax Considerations	The exchange of new notes for old notes in the exchange offer should not be a taxable event for U.S. federal income tax purposes. Please read the discussion under the caption Certain U.S. Federal Tax Considerations for more information regarding the tax consequences to you of the exchange offer.
Use of Proceeds	The issuance of the new notes will not provide us with any new proceeds. We are making this exchange offer solely to satisfy our obligations under the registration rights agreement.
Fees and Expenses	We will pay all of our expenses incident to the exchange offer.
Exchange Agent	We have appointed Wells Fargo Bank, National Association as exchange agent for the exchange offer. You can find the address, telephone number and fax number of the exchange agent under the caption The Exchange Offer Exchange Agent .

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Resales of New Notes	Based on interpretations by the staff of the SEC, as set forth in no-action letters issued to third parties that are not related to us, we believe that the new notes you receive in the exchange offer may be offered for resale, resold or otherwise transferred by you without compliance with the registration and prospectus delivery provisions of the Securities Act so long as: the new notes are being acquired in the ordinary course of business; you are not participating, do not intend to participate, and have no arrangement or understanding with any person to participate in the distribution of the new notes issued to you in the exchange offer; you are not our affiliate; and you are not a broker-dealer tendering old notes acquired directly from us for your account. The SEC has not considered this exchange offer in the context of a no-action letter, and we cannot assure you that the SEC would make similar determinations with respect to this exchange offer. If any of these conditions are not satisfied, or if our belief is not accurate, and you transfer any new notes issued to you in the exchange offer without delivering a resale prospectus meeting the requirements of the Securities Act or without an exemption from registration of your new notes from those requirements, you may incur liability under the Securities Act. We will not assume, nor will we indemnify you against, any such liability. Each broker-dealer that receives new notes for its own account in exchange for old notes, where the old notes were acquired by such broker-dealer as a result of market-making or other trading activities, must acknowledge that it will deliver a prospectus in connection with any resale of such new notes. Please read Plan of Distribution . Please read The Exchange Offer Resales of New Notes for more information regarding resales of the new notes.
Consequences of Not Exchanging Your Old Notes	If you do not exchange your old notes in this exchange offer, you will no longer be able to require us to register your old notes under the Securities Act, except in the limited circumstances provided under the registration rights agreement. In addition, you will not be able to resell, offer to resell or otherwise transfer your old notes unless we have registered the old notes under the Securities Act, or unless you resell, offer to resell or otherwise transfer them under an exemption from the registration requirements of, or in a transaction not subject to, the Securities Act. For information regarding the consequences of not tendering your old notes and our obligation to file a registration statement, please read The Exchange Offer Consequences of Failure to Exchange Outstanding Securities and Description of the Notes .

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Description of the New Notes

The terms of the new notes and those of the outstanding old notes are substantially identical, except that the transfer restrictions and registration rights relating to the old notes do not apply to the new notes. As a result, the new notes will not bear legends restricting their transfer and will not have the benefit of the registration rights and additional interest provisions contained in the old notes. The new notes represent the same debt as the old notes for which they are being exchanged. Both the old notes and the new notes are governed by the same indenture.

The following is a summary of the terms of the new notes. It may not contain all the information that is important to you. For a more detailed description of the new notes, please read Description of the Notes .

Issuer	Gastar Exploration USA, Inc.
Securities Offered	\$100.0 million aggregate principal amount of 12 $^{3}/4$% Senior Secured Notes due 2012. The new notes are being offered as additional debt securities under the indenture pursuant to which we previously issued the old notes.
Interest	Interest on the new notes will accrue at the rate of 12 $^{3}/4$% per year and will be payable semi-annually in arrears on each June 1 and December 1, commencing on June 1, 2008.
Maturity Date	The new notes will mature on December 1, 2012.
Guarantees	The notes will be fully and unconditionally guaranteed on a senior secured basis by each of our existing domestic subsidiaries and future material domestic subsidiaries and Gastar Exploration Ltd., our parent company.
Use of Proceeds	The issuance of the new notes will not provide us with any new proceeds. We are making this exchange offer solely to satisfy our obligations under our registration rights agreement.
Ranking	The new notes will be: equal in right of payment with all our existing and future senior indebtedness; and senior in right of payment to any future subordinated indebtedness. The guarantees of each guarantor will be: equal in right of payment with all of that guarantor s existing and future senior indebtedness, including guarantees; and senior in right of payment to all of that guarantor s future subordinated indebtedness.
Collateral	The new notes and the guarantees will be secured by a lien on our principal oil and gas properties and other assets that secure our revolving credit facility, subject to certain exceptions. Pursuant to the terms of an intercreditor agreement, the lien securing the new notes will be contractually subordinated to the liens that secure our revolving credit facility and certain hedging obligations. Consequently, the new notes and the guarantees will be effectively subordinated to our revolving credit facility to the extent of the value of such assets.
Optional Redemption	We may redeem the new notes, in whole or in part, at any time on and after June 1, 2010 at the redemption prices set forth herein, plus accrued and unpaid interest.

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We may redeem some or all of the new notes at any time prior to June 1, 2010 at the make-whole redemption price set forth in Description of the Notes .

In addition, prior to June 1, 2010, we may redeem up to 35% of the new notes with the net cash proceeds from specified equity offerings at a redemption price equal to 112.750% of the aggregate principal amount, plus accrued and unpaid interest to the date of redemption.

If a change of control, as defined in the indenture, occurs prior to December 1, 2008, the new notes may be redeemed at our option at a price of 112.750% of the principal amount, plus accrued and unpaid interest to the date of redemption. See Description of the Notes Optional Redemption .

Change of Control Offer

If a change of control, as defined in the indenture, occurs, each holder of new notes will have the right to require us to repurchase all or any part of its new notes at a price equal to 101% of their principal amount, plus accrued and unpaid interest.

Asset Sale Proceeds

If we engage in certain asset sales within a period of time we generally must use the net cash proceeds from such sales to repay outstanding senior debt, to acquire another company in our industry or to invest in our own business, or we must make an offer to purchase a principal amount of the new notes equal to the excess net cash proceeds. The purchase price of each new note so purchased will be 100% (or, in some cases, a higher percentage) of its principal amount, plus accrued and unpaid interest.

Certain Covenants

The indenture governing the new notes will, among other things, limit our ability and the ability of our Parent and our restricted subsidiaries to:

- transfer or sell assets;
- make investments;
- pay dividends, redeem subordinated indebtedness or make other restricted payments;
- incur or guarantee additional indebtedness or issue disqualified capital stock;
- create or incur liens;
- incur dividend or other payment restrictions affecting certain subsidiaries;
- consummate a merger, consolidation or sale of all or substantially all of our assets;
- enter into transactions with affiliates; and
- engage in businesses other than the oil and gas business.

Transfer Restrictions

The new notes generally will be freely transferable, but will also be new securities for which there will not initially be a market. There can be no assurance as to the development or liquidity of any market for the new notes.

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Risk Factors

Investing in the new notes involves substantial risk. Please read Risk Factors beginning on page 9 for a discussion of certain factors you should consider in evaluating an investment in the new notes.

In addition to the Risk Factors, you should be aware that we have had a significant deficiency in fixed change coverage in prior years. See Ratio of Earnings to Fixed Changes .

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RISK FACTORS

An investment in the new notes involves a significant degree of risk. You should consider carefully these risks together with all of the other information included in this prospectus and the documents to which we have referred you before deciding whether to invest in the new notes. All of the risks described below could materially and adversely affect our business prospects, financial condition, operating results and cash flows, which in turn could adversely affect our ability to satisfy our obligations under the new notes and the guarantees of the new notes.

Risks Relating to the New Notes and Our Other Indebtedness

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 $30.5 million, $84.8 million and $25.7 million for the years ended December 31, 2007, 2006 and 2005, respectively. 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 and 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.

We have a substantial amount of debt, which may adversely affect our cash flow and our ability to operate our business, to remain in compliance with debt covenants and make payments on our debt.

As March 31, 2008, we had total debt of $133.3 million of which $100.0 million consisted of the 12 $^{3}/4$% Senior Secured Notes, $30.0 million consisted of convertible senior debentures due 2009 and $3.3 million consisted of subordinated unsecured notes due 2009. Our level of indebtedness affects our operations in several ways, including the following:

- We may have difficulty borrowing money in the future for acquisitions, capital expenditures or to meet our operating expenses or other general corporate obligations;
- We will need to use a substantial portion of our cash flows to pay principal and interest on our debt, which will reduce the amount of money we have for operations, working capital, capital expenditures, expansion, acquisitions or general corporate or other business activities;
- We have substantial capital requirements, and we may be unable to obtain needed financing on satisfactory terms;
- We may be more vulnerable to economic downturns and adverse developments in our industry or the economy in general, especially declines in natural gas and oil prices;
- The covenants contained in the agreements governing our outstanding indebtedness limit our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments; and
- Our debt covenants may affect our flexibility in planning for and reacting to changes in the economy or in our industry.

We may incur substantially more debt, which may intensify the risks described above, including our ability to service our indebtedness.

We may need to incur substantially more debt in the future. Although the indenture governing the 12 $^{3}/4$% Senior Secured Notes and our revolving credit facility contain restrictions on our incurrence of additional indebtedness, these restrictions are subject to a number of qualifications and exceptions, and under certain circumstances, indebtedness incurred in compliance with these restrictions could be substantial. In addition, the indenture governing the new notes and our revolving credit facility will not prevent us from incurring obligations that do not constitute indebtedness. See Description of the Notes Certain Covenants Incurrence of Indebtedness and Issuance of Preferred Stock . To the extent new indebtedness is added to our current indebtedness levels, the risks described above could substantially intensify.

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To service our indebtedness, we will require a significant amount of cash. Our ability to generate cash depends on many factors beyond our control, and any failure to meet our debt obligations could harm our business, financial condition and results of operations.

Our ability to make interest payments on and to repay our indebtedness, including the new notes, and to fund planned capital expenditures will depend on our ability to generate cash from operations in the future. This, to a certain extent, is subject to general economic, financial, competitive, legislative, regulatory and other factors that are beyond our control, including the prices that we receive for natural gas and oil. We cannot assure you that our business will generate sufficient cash flow from operations or that future borrowings will be available to us under our revolving credit facility in an amount sufficient to enable us to make interest payments on and to repay our indebtedness, including the new notes, or to fund our other liquidity needs.

If our cash flow and capital resources are insufficient to fund our debt obligations, we may be forced to sell assets, seek additional equity or debt capital or restructure our debt. Our Australian joint ventures include a contractual priority over production to satisfy joint venture debts as against secured creditors. The indenture governing the old notes, the new notes and our revolving credit facility will restrict our ability to dispose of assets and use the proceeds from any such disposition. We cannot assure you that any of these remedies could, if necessary, be effected on commercially reasonable terms, or at all. In addition, any failure to make scheduled payments of interest and principal on our outstanding indebtedness, including our revolving credit facility, would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness on acceptable terms. If we fail to meet our payment obligations under our revolving credit facility, those lenders would be entitled to foreclose on substantially all of our assets and liquidate those assets. Under those circumstances, our cash flow and capital resources would be insufficient for payment of interest on and principal of our debt in the future, including interest payments on the new notes and the old notes, and any such alternative measures may be unsuccessful or may not permit us to meet scheduled debt service obligations, which could cause us to default on our obligations, impair our liquidity, or cause the holders of the new notes to lose a portion of or the entire value of their investment.

A default on our obligations could result in:

- Our debt holders declaring all outstanding principal and interest due and payable;
- The lenders under our revolving credit facility terminating their commitments to loan us money and foreclosing against the assets securing their loans to us; and
- Our bankruptcy or liquidation, which is likely to result in delays in the payment of the new notes and in the exercise of enforcement remedies under the new notes or the subsidiary guarantees.

In addition, provisions under the bankruptcy code or general principles of equity that could result in the impairment of your rights include the automatic stay, avoidance of preferential transfers by a trustee or a debtor-in-possession, limitations of collectibility of unmatured interest or attorneys fees and forced restructuring of the new notes.

Restrictive debt covenants in the indenture and our revolving credit facility will restrict our business in many ways.

The indenture governing the new notes will contain a number of significant covenants that, among other things, will restrict our ability to:

- Transfer or sell assets;
- Make investments;

Pay dividends, redeem subordinated indebtedness or make other restricted payments;

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- Incur or guarantee additional indebtedness or issue disqualified capital stock;
- Create or incur liens;
- Incur dividend or other payment restrictions affecting certain subsidiaries;
- Consummate a merger, consolidation or sale of all or substantially all of our assets;
- Enter into transactions with affiliates; and
- Engage in businesses other than the natural gas and oil business.

These covenants could limit our ability to obtain future financings, make needed capital expenditures, withstand a future downturn in our business or the economy in general or otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants impose on us. A breach of any of these covenants could result in a default under the new notes which, if not cured or waived, could result in acceleration of the new notes. See Description of the Notes Events of Default and Remedies .

In addition, our revolving credit facility contains restrictive covenants and requires us to maintain specified financial ratios and satisfy other financial condition tests. Our ability to meet those financial ratios and tests can be affected by events beyond our control, and we cannot assure you that we will meet those tests. A breach of any of these covenants could result in a default under the facility. Upon the occurrence of an event of default, the lenders could elect to declare all amounts outstanding to be immediately due and payable and terminate all commitments to extend further credit. If we were unable to repay those amounts, the lenders could proceed against the collateral granted to them to secure that indebtedness. We have pledged substantially all of our assets as collateral under the revolving credit facility, including our ownership interests in our subsidiaries. If the lenders accelerate our repayment of borrowings, we cannot assure you that we will have sufficient assets to repay our revolving credit facility and our other indebtedness, including the new notes.

Our borrowings under our revolving credit facility expose us to interest rate risk.

Our borrowings under our revolving credit facility are, and are expected to continue to be, at variable rates of interest and expose us to interest rate risk. If interest rates increase, our debt service obligations on the variable rate indebtedness would increase even though the amount borrowed remained the same, and our net loss would increase.

There may not be sufficient collateral to pay all or any of the new notes.

Indebtedness and other obligations under our revolving credit facility, the new notes and certain other senior secured indebtedness that we may incur in the future will be secured by a lien on substantially all of our tangible and intangible assets. Pursuant to the terms of an intercreditor agreement, the security interest in those assets that secure the new notes and guarantees of our current domestic subsidiaries and future material domestic subsidiaries will be contractually subordinated to a lien thereon that secures our revolving credit facility and certain other permitted indebtedness. Therefore, in the event of a bankruptcy, liquidation, dissolution, reorganization or similar proceeding involving us, or an acceleration of our first priority claims, such assets that secure these first priority claims and the new notes must be used first to pay first priority claims in full before any payments are made therewith on the new notes.

No fair market value appraisals of any collateral have been prepared in connection with this offering of the new notes. The value of the collateral at any time will depend on market and other economic conditions, including the availability of suitable buyers for the collateral. By its nature, some or all of the collateral may be illiquid and may have no readily ascertainable market value. The value of the assets pledged as collateral for the new notes could be impaired in the future as a result of changing economic conditions, competition or other future trends. In the event of a foreclosure, liquidation, bankruptcy or similar proceeding, no assurance can be given that the proceeds from any sale or liquidation of the collateral will be sufficient to pay our obligations under the new notes, in full or at all, after first satisfying our obligations in full under first priority claims. See the section entitled Description of the Notes Collateral . Accordingly, there may not be sufficient collateral to pay all or any of the amounts due on the new notes.

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To the extent that third parties enjoy prior liens, such third parties may have rights and remedies with respect to the property subject to such liens that, if exercised, could adversely affect the value of the collateral. Additionally, the terms of the indenture allow us to issue additional notes in certain circumstances. The indenture will not require that we maintain the current level of collateral value or maintain a specific ratio of indebtedness to asset values. Any additional notes issued pursuant to the indenture will rank pari passu with the new notes and be entitled to the same rights and priority with respect to the collateral. Thus, the issuance of additional notes pursuant to the indenture may have the effect of significantly diluting your ability to recover payment in full from the then existing pool of collateral. Releases of collateral from the liens securing the new notes will be permitted under some circumstances. See Description of the Notes Collateral .

The collateral is subject to casualty risks.

We will be obligated under the collateral arrangements to maintain adequate insurance or otherwise insure against hazards as is usually done by corporations operating properties of a similar nature in the same or similar localities. The Australian assets insurances are procured by the operator of the relevant joint venture (acting as a reasonable and prudent operator) to cover joint venture loss and include deductibles. There are, however, certain losses that may be either uninsurable or not economically insurable, in whole or in part. As a result, it is possible that the insurance proceeds will not compensate us fully for our losses. If there is a total or partial loss of any of the pledged collateral, we cannot assure you that any insurance proceeds received by us will be sufficient to satisfy all of our secured obligations, including the new notes.

Holders of new notes will not control decisions regarding collateral.

In connection with entering into our revolving credit facility, we entered into an intercreditor agreement with the agent under our revolving credit facility, which provides that, among other things, (1) the holders of the first priority claims and the agent under our revolving credit facility control substantially all matters related to the collateral that secures the first priority claims and the new notes; (2) the holders of first priority claims and the agent under our revolving credit facility may foreclose on or take other actions with respect to such collateral with which holders of the new notes may disagree or that may be contrary to the interests of holders of the new notes; (3) to the extent certain collateral is released from securing first priority claims to satisfy such claims, the liens securing the new notes will also automatically be released without any further action; and (4) the holders of the new notes will agree to waive certain of their rights in connection with a bankruptcy or insolvency proceeding involving us or any guarantor of the new notes. See Description of the Notes Collateral Intercreditor Agreement .

In the event of a bankruptcy, the ability of the noteholders to realize the collateral will be subject to certain bankruptcy law limitations.

The right of the collateral agent for the new notes to repossess and dispose of the collateral securing the new notes upon acceleration is likely to be significantly impaired by federal bankruptcy law if bankruptcy proceedings are commenced by or against us prior to or possibly even after the collateral agent has repossessed and disposed of the collateral. Under the U.S. Bankruptcy Code, a secured creditor, such as the collateral agent for the new notes, is prohibited from repossessing its security from a debtor in a bankruptcy case, or from disposing of security repossessed from a debtor, without bankruptcy court approval. Moreover, bankruptcy law permits the debtor to continue to retain and to use collateral, and the proceeds, products, rents, or profits of the collateral, even though the debtor is in default under the applicable debt instruments, provided that the secured creditor is given adequate protection . The meaning of the term adequate protection may vary according to circumstances, but it is intended in general to protect the value of the secured creditor s interest in the collateral and may include cash payments or the granting of additional security, if and at such time as the court in its discretion determines, for any diminution in the value of the collateral as a result of the stay of repossession or disposition or any use of the collateral by the debtor during the pendency of the bankruptcy case. In view of the broad discretionary powers of a bankruptcy court, it is impossible to predict how long payments under the new notes could be delayed following commencement of a bankruptcy case, whether or when the collateral agent would repossess or dispose of the collateral, or whether or to what extent holders of the new notes would be compensated for any delay in payment of loss of value of the collateral through the requirements of adequate protection . Furthermore, in the event the bankruptcy court

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determines that the value of the collateral is not sufficient to repay all amounts due on the new notes, the holders of the new notes would have undersecured claims as to the difference. Federal bankruptcy laws do not permit the payment or accrual of interest, costs, and attorneys fees for undersecured claims during the debtor s bankruptcy case.

Rights of noteholders in the collateral may be adversely affected by the failure to perfect security interests in certain collateral existing or acquired in the future.

The security interest in the collateral securing the new notes includes certain of our domestic assets, both tangible and intangible, whether now owned or acquired or arising in the future. Our Australian properties do not constitute any of the collateral securing the new notes. There can be no assurance that the trustee or the collateral agent will monitor, or that we will inform the trustee or the collateral agent of, the future acquisition of oil and gas property and rights that constitute collateral, and that the necessary action will be taken to properly perfect the security interest in such after acquired collateral. The failure to perfect a security interest in respect of such acquired collateral may result in the loss of the security interest therein or the priority of the security interest in favor of the new notes against third parties, subject to the priority order set out in joint venture agreements. If we or any guarantor were to become subject to a bankruptcy proceeding after the issue date of the new notes, any liens recorded or perfected after the issue date of the new notes would face a greater risk of being invalidated than if they had been recorded or perfected on the issue date. If a lien is recorded or perfected after the issue date, it may be treated under bankruptcy law as if it were delivered to secure previously existing debt. In bankruptcy proceedings commenced within 90 days of lien perfection, a lien given to secure previously existing debt is materially more likely to be avoided as a preference by the bankruptcy court than if delivered and promptly recorded on the issue date of the new notes. Accordingly, if we or a guarantor were to file for bankruptcy after the issue date of the new notes and the liens had been perfected less than 90 days before commencement of such bankruptcy proceeding, the liens securing the new notes may be especially subject to challenge as a result of having been delivered after the issue date of the new notes. To the extent that such challenge succeeded, you would lose the benefit of the security that the collateral was intended to provide.

A court could cancel the new notes or the guarantees of our current domestic subsidiaries and future material domestic subsidiaries, our Parent and security interests under fraudulent conveyance laws or certain other circumstances.

Our issuance of the new notes and the issuance of the guarantees by our current and future subsidiaries and our Parent may be subject to review under federal or state fraudulent transfer or similar laws.

All of our current domestic and future material domestic subsidiaries and our Parent will guarantee the new notes. If we, our Parent or such a subsidiary becomes a debtor in a case under the Bankruptcy Code or encounters other financial difficulty, under federal or state laws governing fraudulent conveyance, renewable transactions or preferential payments, a court in the relevant jurisdiction might avoid or cancel its guarantee and/or the liens created by the security interest. The court might do so if it found that, when the subsidiary or our Parent entered into its guarantee and security arrangement or, in some states, when payments become due thereunder, (a) it received less than reasonably equivalent value or fair consideration for such guarantee and/or security arrangement and (b) either (i) was or was rendered insolvent, (ii) was left with inadequate capital to conduct its business, (iii) or believed or should have believed that it would incur debts beyond its ability to pay. The court might also avoid such guarantee and/or security arrangement, without regard to the above factors, if it found that the subsidiary or our Parent entered into its guarantee and/or security arrangement with actual or deemed intent to hinder, delay, or defraud our creditors.

Similarly, if we become a debtor in a case under the Bankruptcy Code or encounter other financial difficulty, a court might cancel our obligations under the new notes, if it found that when we issued the new notes (or in some jurisdictions, when payments become due under the new notes), factors (a) and (b) above applied to us, or if it found that we issued the new notes with actual intent to hinder, delay or defraud our creditors.

A court would likely find that a subsidiary or our Parent did not receive reasonably equivalent value or fair consideration for its guarantee unless it benefited directly or indirectly from the issuance of the new notes. If a court avoided such guarantee, holders of the new notes would no longer have a claim against such subsidiary or our Parent. In addition, the court might direct holders of the new notes to repay any amounts already received from such subsidiary or our Parent. If the court were to avoid any guarantee, we cannot assure you that funds would be available to pay the new notes from another subsidiary or our Parent or from any other source.

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The indenture states that the liability of each subsidiary and our Parent on its guarantee and security arrangement is limited to the maximum amount that the subsidiary or our Parent can incur without risk that the guarantee or security arrangement will be subject to avoidance as a fraudulent conveyance. This limitation may not protect the guarantees and/or security arrangements from a fraudulent conveyance attack or, if it does, the guarantees and/or security arrangements may not be in amounts sufficient, if necessary, to pay obligations under the new notes when due.

The trading price of the new notes may be volatile.

Historically, the market for non-investment grade debt has been subject to disruptions that have caused substantial volatility in the prices of securities similar to the new notes. Any such disruptions could adversely affect the prices at which you may sell the new notes. In addition, the new notes may trade at a discount from the initial offering price of the old notes, depending on prevailing interest rates, the market for similar notes, our performance and other factors, many of which are beyond our control.

We may not have the ability to raise the funds necessary to finance any change of control offer required by the indenture governing the new notes.

Upon the occurrence of a change of control, as defined in the indenture governing the new notes, we will be required to offer to repurchase all outstanding new notes at a price equal to 101% of the principal amount of the new notes, together with accrued and unpaid interest, if any, to the date of repurchase.

However, it is possible that we will not have sufficient funds at the time of a change of control to make the required repurchase of the new notes or that restrictions in our revolving credit facility will not allow such repurchases. If the indebtedness under our revolving credit facility is not paid, the lenders thereunder may seek to enforce their security interests in the collateral securing such indebtedness thereby limiting our ability to raise cash to purchase the new notes and reducing the practical benefit of the offer to purchase provisions of the new notes. See Description of the Notes Repurchase at the Option of Holders .

One of the circumstances under which a change of control may occur is upon the sale or disposition of all or substantially all of our capital stock or assets. However, the phrase all or substantially all will likely be interpreted under applicable state law and will be dependent upon particular facts and circumstances. As a result, there may be a degree of uncertainty in ascertaining whether a sale or disposition of all or substantially all of our capital stock or assets has occurred, in which case, the ability of a holder of the new notes to obtain the benefit of an offer to repurchase all of a portion of the new notes held by such holder may be impaired.

The purchase requirements contained in our debt instruments could also delay or make it harder for others to effect a change of control. However, certain other corporate events, such as a leveraged recapitalization that would increase our level of indebtedness, would not necessarily constitute a change of control under the indenture governing the new notes. Upon the occurrence of a change of control we could seek to refinance the indebtedness under our new revolving credit facility and the new notes, obtain a waiver from the lenders and the holders of the new notes or seek third party financing to repurchase the new notes. We cannot assure you, however, that we would be able to obtain waivers or refinance our indebtedness or secure third party financing on commercially reasonable terms, if at all. See Description of the Notes Repurchase at the Option of Holders .

There may be no public market for the new notes.

The new notes will be new securities for which currently there is no trading market. We do not intend to apply for the new notes to be listed on any securities exchange or to arrange for any quotation system to quote them. The liquidity of any market for the new notes will depend on the number of holders of those new notes, the interest of securities dealers in making a market in those securities and other factors. Accordingly, we cannot assure you as to:

- The liquidity of any such market that may develop;

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- Your ability to sell your new notes; or

- The price at which you would be able to sell your new notes.

If such a market were to exist, the new notes could trade at prices that may be lower than the principal amount or purchase price, depending on many factors, including prevailing interest rates, the market for similar new notes and our financial performance. If an active market does not develop or is not maintained, the price and liquidity of the new notes may be adversely affected.

If you fail to exchange your old notes, the existing transfer restrictions will remain in effect and the market value of your old notes may be adversely affected because they may be more difficult to sell.

If you fail to exchange your old notes for new notes under the exchange offer, then you will continue to be subject to the existing transfer restrictions on your old notes. In general, the old notes may not be offered or sold unless they are registered or exempt from registration under the Securities Act and applicable state securities laws. Except in connection with this exchange offer or as required by the registration rights agreement, we do not intend to register resales of the old notes.

The tender of old notes under the exchange offer will reduce the principal amount of the old notes outstanding. Due to the corresponding reduction in liquidity, this may have an adverse effect upon, and increase the volatility of, the market price of any old notes that you continue to hold following completion of the exchange offer.

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 and results of operations.

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 have a material adverse 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. Natural gas and oil prices will likely 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, such as Venezuela;

- Domestic and foreign governmental regulations;

- The level of consumer product demand; and

The price and availability of alternative fuels.

Our success is influenced by 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 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. As of March 31, 2008, approximately 79% of our production is priced based on the Katy Hub (Katy) basis point, and the remainder is priced on the CIG basis point. Recently, natural gas prices on CIG

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have been extremely volatile, and spot sales of natural gas in the region traded at prices substantially below historic levels, when compared to prices in other primary natural gas sales points in the country. This has been attributed primarily to limitations in available pipeline capacity for natural gas deliveries out of the Rocky Mountain area. In 2007, spot prices for CIG Rocky Mountains on occasion dipped to less than $1.00 per MMBtu. While this volatility currently has been alleviated by completion of a major pipeline system in January 2008, this relief may be offset over time by the expected increase in supply of natural gas available in the Rocky Mountains. For the three months ended March 31, 2008, the Katy hub basis traded at approximately 3% less than Henry Hub, and CIG hub basis traded at approximately 11% less then Henry Hub. Low natural gas prices in any or all of the areas where we operate would negatively impact our financial condition and results of operations.

In Victoria and New South Wales the wholesale price for gas is determined by contract negotiations and is not related to a hub or spot market price. Prospective natural gas sales related to our pilot CBM project in New South Wales will be dependent on electricity prices in the area since the natural gas is being dedicated initially as fuel for an electric generation facility.

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

Our future natural gas and oil production depends on our success in finding or acquiring new reserves. If we fail to replace reserves, our level of production and cash flows would be adversely impacted. Production from natural gas and oil properties decline as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our total proved reserves will decline as reserves are produced unless we conduct successful exploration and development activities and/or acquire properties containing proved reserves. 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, which could have a material adverse effect on our financial condition, future cash flows and the results of operations.

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 have a material adverse affect our financial condition, 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.

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Disputes have arisen between GeoStar and us in connection with the POA, general operating and administrative activity, and purchase price adjustments relating to certain Texas properties.

Over the past years, we entered into various transactions or agreements with GeoStar, one of our former major shareholders and an affiliate of our former Chairman of the Board. In 2001, we entered into a Participation and Operating Agreement (the POA) with GeoStar that governed certain property acquisition, exploration and development activities of GeoStar and us. Various disputes have arisen, primarily over the past year, in connection with the POA and general operating and administrative activity between GeoStar and us. GeoStar claims that we have breached alleged agreements to reimburse it for various payments and services allegedly performed by GeoStar and its personnel and paid on our behalf by GeoStar. GeoStar claims that the amounts of the payments and the value of the services exceed $17.0 million. GeoStar alternatively alleges that if there was no contract covering those payments and services, it allegedly is entitled to reimbursement on equitable principles. We have also requested that GeoStar s Australian subsidiary provide a record title assignment of our 75% beneficial interests in EL 4416, the exploration license in the Gippsland Basin property in Victoria, Australia. GeoStar seeks a declaration that we do not own rights in EL 4416. Although we strongly contend that these additional GeoStar charges are without merit and that GeoStar owes us approximately $3.7 million at December 31, 2007, we may not prevail. Payment to GeoStar of the amounts asserted would have a material adverse effect on our financial condition, future cash flows and the result of operations.

In addition, a dispute has arisen regarding the Purchase and Sale Agreements (the PSAs) between GeoStar and us relating to certain East Texas properties acquired by us in 2005. The PSAs contain a provision whereby a Look Back Payment is calculated based in part on changes in proved and probable reserves attributable to certain of our East Texas leasehold interests over certain periods of time. Payments to GeoStar under the PSAs, if any, are to be effected through the issuance of our common shares. On November 7, 2007, GeoStar submitted a reserve report to us that reports substantially greater reserve estimates than the estimates we have obtained. GeoStar has also asserted that the Look Back analysis should be based on changes in reserves attributable to the entirety, or 8/8ths, of the leasehold interests with respect to the East Texas properties, rather than on changes in reserves attributable to GeoStar s net revenue interest in those properties as of the effectiveness of the PSAs, as we believe. We vigorously dispute that GeoStar s reserves report complies with the requirements of the PSAs and vigorously dispute GeoStar s contention as to the portion of reserves subject to the Look Back analysis. However, if GeoStar were to present both of these current assertions in litigation and obtain an outcome adverse to the Company on both issues, we could be required to issue a number of shares to GeoStar sufficient to cause a change in control of the ownership of Gastar.

In 2007, we recorded a $1.4 million litigation settlement expense accrual related to a proposed settlement with GeoStar regarding the various GeoStar arbitration and litigation matters. The settlement proposal was never finalized. Information about our legal proceedings is set forth in Note 16 Commitments and Contingencies Litigation to our consolidated financial statements, which begin on Page F-1.

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 drilling an exploration well, the operator of the well will typically obtain a preliminary title review of the drillsite lease 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. 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 and results of operations. Information about our legal proceedings is set forth in Note 16 Commitments and Contingencies Litigation to our consolidated financial statements, which begin on page F-1.

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A dispute between third parties affecting the ownership of undivided interests in certain East Texas oil and gas leases that we sold in 2005 may make it difficult for us, as operator of those leases, to obtain funds for some of our planned joint drilling operations until the dispute is resolved.

In 2005, we sold Chesapeake Energy Corporation a one-third undivided interest in various oil and gas leases, located in Leon and Robertson Counties, Texas together with shares of our common stock. Navasota Resources, L.P. filed a lawsuit against us and Chesapeake asserting a preferential right to purchase the undivided leasehold interest under an operating agreement. While this issue was resolved by the trial court in favor of Chesapeake, an appeals court has recently reversed and rendered judgment favoring Navasota s right to acquire the undivided interest. Together with Chesapeake, we filed a motion for rehearing and, if unsuccessful, may consider an appeal to the Texas Supreme Court. While ownership of this undivided leasehold interest remains unresolved, Chesapeake and Navasota are disputing responsibility for paying the proportionate share of joint capital and operating costs relating to this interest or approving authorizations for future joint drilling expenditures. Delays in determining ultimate ownership of this interest could lead to our paying a disproportionate share of costs at our own risk or result in a delay in drilling of wells planned on this acreage in East Texas, which could have a material adverse effect on our financial condition, future cash flows and the results of operations.

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

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

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

- Historical natural gas or oil production from that area, compared with production from other producing areas;
- The assumed effects of regulations by governmental agencies;
- Assumptions concerning future prices;
- Assumptions concerning future operating costs;
- Assumptions concerning severance and excise taxes; and
- Assumptions concerning development costs and workover and remedial costs.

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

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

The amount and timing of actual production;

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Supply and demand for natural gas or oil;

Actual prices received for natural gas in the future being different than those used in the estimate;

Curtailments or increases in consumption of natural gas or oil;

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, 2007, approximately 60% 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. Our estimate of proved reserves at December 31, 2007 assumes that we will spend significant development capital expenditures to develop these reserves, including an estimated $39.1 million and $9.5 million in 2008 and 2009, respectively. 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 adverse effect on our financial condition, future cash flows and the results of operations.

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 could intensify with 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 entered into contracts for the services of drilling rigs in North America and Australia, we may not be successful in doing so in the future. 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 have a material adverse effect on our financial condition, future cash flows and the results of operations.

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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.

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 obligations, 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 or subject to reinterpretation and may be 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 effect on our financial condition, future cash flows and the 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. Joint and several, strict liability may be incurred without regard to fault or the legality of the original conduct under certain of these laws and regulations for the remediation of contaminated areas. Private parties, including the owners of properties located near our storage facilities or through which our pipeline systems pass, also may have the right to pursue legal actions to enforce compliance, as well as seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. Consequently, the discharge or release of natural gas, oil or other substances into the air, soil or water, even by predecessor operators, could subject us to liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury, property and natural resource 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.

Native title, which is based on the traditional laws of Aboriginal groups, was recognized in Australia in 1992. Since 1994 there has been a process under the Native Title Act 1993 (Cth) through which indigenous groups claiming to hold native title can have their title formally recognized. Because native title, by definition, has existed uninterrupted since white settlement of Australia, claims with a reasonable prospect of success are registered and

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registered claimants have certain rights to participate in government land use decisions affecting land to which they may hold native title. Through the claims process, there are some areas in Australia where native title is now formally recognized. However, in New South Wales and Victoria, where we have our Australian operations, most native title claims are yet to be resolved.

Native title can and has been extinguished across much of Australia and cannot be revived. Native title may be wholly extinguished in relation to particular areas of land by a grant of an inconsistent title, such as freehold or a lease conferring exclusive possession. Where this has occurred it is possible to determine that native title has been extinguished irrespective of the formal resolution of a claim. Native title has no effect in relation to land use in such areas. Native title is also extinguished where the traditional Aboriginal owners have lost their traditional links to the land. This can usually only be determined through the claim resolution process.

Native title can impact our Australian operations in two important ways:

- Validity of interests: Where we are seeking to obtain an authority to prospect, develop resources or construct a pipeline over land subject to a registered native title claim or determination, in respect of which prior extinguishment cannot be demonstrated, it is necessary to follow the processes contained in the Commonwealth native title the Native Title Act 1993 (Cth) to ensure validity of the authority insofar as it affects native title.

- Costs and delays associated with procedural rights of registered native title claimants/holders when seeking government authorities: Under the Native Title Act 1993 (Cth), registered native title claimants or holders (native title parties) have certain procedural rights in relation to the grant of authorities by the state government in respect of land to which they may or do hold native title. We may be required to attempt to reach agreement with any native title parties as to the terms on which they will agree to the grant of the authority we seek. Such an agreement may include immediate payments, revenue sharing, or both. Payments are likely to apply even before the claim is formally resolved. An agreement may also restrict the area where prospecting or development can occur in order to ensure that areas of cultural heritage significance are preserved. Reaching agreement with a native title party can be costly and cause delay. Generally, the costs associated with the grant of pipeline licenses are less than those for production approvals. It is possible to request the National Native Title Tribunal to arbitrate a dispute regarding the terms on which a prospecting or production authority can be granted, if there has been no resolution after six months. Other processes are available for resolution of disputes regarding pipeline licensing approvals according to state laws.

There are registered native title claims in the Gunnedah Basin in New South Wales affecting PEL 238 and 433. EL 4416 in the Gippsland Basin in Victoria is not presently subject to a native title claim. However, a claim may be lodged which affects this property in the future.

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;

Pipeline ruptures or spills;

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- 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. 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 79% of our revenues for the three months ended March 31, 2008 was from the production of wells located in our Hilltop area play in East Texas. Any disruption in production or our ability to process and sell our natural gas production from this area would have a material adverse effect on our results of operations.

Production of the natural gas in East Texas could unexpectedly be disrupted or curtailed due to reservoir or mechanical problems. Our natural gas produced from this area contains levels of carbon dioxide and hydrogen sulfide that are above levels accepted by gas purchasers. This production must be treated by the purchaser. A majority of our East Texas production is processed by the purchaser. If the purchaser s facilities ceased to operate, were destroyed or otherwise needed replacement, it could require 60 to 90 days to replace or repair these facilities. A 60 to 90 day curtailment of our East Texas production could reduce current revenues by an estimated $9.3 million to $13.9 million, with a corresponding reduction in our cash flow.

The CBM which we produce in the Powder River Basin may be drained by offsetting production wells.

Our drilling locations in the Powder River Basin are spaced primarily using 80-acre spacing. Producing wells located on the 80-acre spacing units contiguous with our drilling locations may drain the acreage underlying our wells. If a substantial number of productive wells are drilled on spacing units adjacent to our properties, they may decrease our revenue and could have an adverse impact on the economically recoverable reserves of our properties that are susceptible to such drainage.

Our Powder River Basin CBM wells typically have a shorter reserve life and lower rates of production than conventional natural gas wells, which may adversely affect our profitability during periods of low natural gas prices.

The shallow coals from which we produce CBM in the Powder River Basin typically have a two to six year reserve life and have lower total reserves and produce at lower rates than most conventional natural gas wells. We depend on drilling a large number of wells each year to replace production and reserves in the Powder River Basin and to distribute operational expenses over a larger number of wells. A decline in natural gas prices could make certain wells uneconomical because production rates are lower on an individual well basis and may be insufficient to cover operational costs.

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There are a limited number of natural gas purchasers and transporters in the Hilltop area of our deep Bossier play in East Texas. The loss of our current purchaser and transporter and an inability to locate another purchaser and transporter would have a material adverse effect on our financial condition and results of operations.

There are a limited number of natural gas transporters in the Hilltop area in East Texas. For the year ended December 31, 2007, ETC accounted for substantially all of our revenues from this area. If ETC were to cease purchasing and transporting our natural gas and we were unable to contract with another transporter, it would have a material adverse effect on our financial condition, future cash flows and the results of operations.

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 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.

In recent years pipeline capacity for natural gas deliveries out of the Rocky Mountain area has been, at times, significantly constrained resulting in an oversupply and creating substantial discounts on spot natural gas prices received for regional production. This has had a substantial impact on the prices received for natural gas production from Wyoming and Montana, as compared to Gulf Coast natural gas prices. While a recently completed interstate pipeline currently has alleviated the problem by providing access to the Midwest interstate pipelines and markets, the relief may be offset over time by the expected increase in supply of natural gas available in the Rocky Mountains.

Australian natural gas markets and transmission infrastructure exists but they are not as developed or interconnected as the markets and infrastructure in the United States. Specifically, the PEL 238 concession is currently not served by natural gas transmission infrastructure. The initial gas market for PEL 238 natural gas is anticipated to be an electricity generation facility located near the town of Narrabri, New South Wales. A short transmission pipeline is required to be built to serve this initial market. Access to a larger electricity facility will require construction of a pipeline of approximately 300 kilometers to reach PEL 238 with an additional 150 kilometers of pipeline infrastructure required to access the natural gas markets in the Sydney-Newcastle-Wollongong markets. The capital costs for these projects, if deemed feasible, would be substantial in order to realize the value of any identified reserves and construction would require significant amounts of time.

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. At the time production commences, the existing pipelines may have constraints in the capacity available to transport natural gas from the EL 4416 license to markets in the area of Sydney, Melbourne and Tasmania.

Our exploration rights in Australia are subject to renewal at the discretion of the government.

Coal bed methane exploration in Victoria is conducted under an exploration license granted under the *Mineral Resources (Sustainable Development) Act 1990 (Victoria)* which is granted at the discretion of the Minister for Primary Industries. Each exploration license requires the expenditure of a set amount of exploration costs and is generally subject to renewal for five years after the initial term of five years. On renewal of an exploration license, the Minister may require reduction of the area to which the exploration license applies.

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Coal bed methane exploration in New South Wales is conducted under a Petroleum Exploration License (PEL) granted under the Petroleum (Onshore) Act 1991 (NSW), which is granted at the discretion of the Minister. Each PEL requires the expenditure of a set amount of exploration costs and is generally subject to renewal a term of up to six years after the initial term of up to six years. On renewal of a PEL, the Minister may require reduction of the area to which the PEL applies.

We cannot assure that our exploration licenses or PELs will be renewed. Non-renewal or loss of an exploration licenses or PELs could adversely affect our exploration and development plans, results of operations, financial condition or cash flows.

Competition in the natural gas and oil industry is intense. We are smaller and have less operating history than many 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 have a material adverse effect on our financial condition, future cash flows and the 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;

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- 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.

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 have a material adverse affect on 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, many 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. If one or more of the technologies that we currently use or may implement in the future were to become obsolete or if we are unable to use the most advanced commercially available technology, it could have a material adverse effect on our financial condition, future cash flows and the results of operations.

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 and maximize our business plan is dependent on our ability to obtain adequate financing.

Our 2008 capital expenditures under our current business plan are estimated to total approximately $65.4 million, of which $43.4 million is estimated to be spent on unconventional natural gas and oil exploration and development operations in East Texas, $7.4 million is estimated to be spent on CBM projects and additional projects in the United States and $14.6 million is estimated to be spent on CBM projects in Australia. Our business plan, which includes participation in 3-D seismic shoots, the drilling of exploration prospects and development projects

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and producing property acquisitions, has required and will continue to require substantial capital expenditures. We will require additional financing to fund our planned growth and scheduled debt maturities beyond the next 12 months. 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 credit agreements 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.

Disputes with GeoStar may make it difficult for us to raise capital through the sale of equity.

The 2005 Purchase and Sale Agreements, or 2005 PSAs, between GeoStar and the Company relating to certain East Texas properties acquired by the Company contain a look back contingent payment provision that is the subject of claims in certain litigation matters with GeoStar. The 2005 PSAs sets forth a formula by which the amount of the look back payment is based in large part upon estimates of proved and probable reserves attributable to the East Texas properties as of June 30 of 2006 and 2007. Under the 2005 PSAs, the look back payment is to be settled by the issuance of our common shares. GeoStar asserts that, under its calculations, it is entitled to a look back payment of approximately 1.7 billion shares of our common stock, which if issued would constitute approximately 89% of our outstanding common equity. We strongly dispute GeoStar s assertions. While these litigation matters remain pending, it will be difficult for us to raise equity capital through the sale of our common stock to fund future operations and capital needs. Information about our legal proceedings with GeoStar is set forth under the caption Litigation Arbitration and Litigation with GeoStar and its Affiliates in Note 16 Commitments and Contingencies to our consolidated financial statements, which begin on page F-1.

Hedging of our production may result in losses or prevent us from benefiting to the fullest extent possible from increases in prices for natural gas and oil.

In September 2007, we commenced hedging our natural gas production utilizing costless collars. Although these hedges may partially protect us from by declines in natural gas prices, the use of these arrangements may limit our ability to benefit from significant increases in the prices of natural gas.

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, chief financial officer and chief operating officer could negatively impact our future operations. We have employment agreements 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 financial condition, future cash flows and the results of operations.

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

As of March 31, 2008, Chesapeake Energy Corporation owned approximately 16.3% of our outstanding common shares. As a result, Chesapeake is in a position to heavily influence the outcome of matters requiring a shareholder vote, including the election of directors, the adoption of or amendment to provisions in our Amended and Restated Articles of Incorporation, 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. Chesapeake has the right to have an observer present at our board of directors meetings.

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Chesapeake and its subsidiaries are also engaged in the natural gas and oil business. Although we have entered into a joint operating agreement with Chesapeake, it is possible that we may in some circumstances be in direct or indirect competition with Chesapeake, including competition with respect to certain business strategies and transactions that we may propose to undertake. These conflicts of interest may have a material adverse affect our results of operations.

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

Two 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 will enforce judgments of United States courts obtained in actions against those directors predicated upon the civil liability provisions of the United States federal securities laws or the securities or blue sky laws of any state within the United States or 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.

A change of control of the Company could have a material adverse effect on us, and if GeoStar prevails in its look back claim, it could result in a change of control of the Company.

Under the terms or agreements for our 12 $^{3}/4$% Senior Secured Notes, our revolving credit facility and the convertible senior debentures, which collectively constitute substantially all of our indebtedness, upon the occurrence of specific types of changes of control in the Company, we will be required to either repay or make an offer to repurchase all outstanding debt under these agreements. If such a change of control were to occur, including as a result of payment of a disputed look back payment if GeoStar were to prevail in its assertion discussed elsewhere in this report, we may not have sufficient funds available to repay debt becoming due or repurchase debt tendered to us. In that event, we would need to seek waivers from lenders and debtholders, which may not be obtainable, or a refinancing, which may not be available or on terms as favorable as the refinanced debt. Such a required repayment, repurchase or refinancing could have a material adverse effect on our financial condition, future cash flows and the results of operations.

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RATIO OF EARNINGS TO FIXED CHARGES

We have computed our ratio of earnings to fixed charges for the three months ended March 31, 2008 and 2007 and for each of our fiscal years ended December 31, 2007, 2006, 2005, 2004 and 2003. As we reported losses (deficiency with fixed charges)in each of the periods reported, our ratio of earnings to fixed charges was less than zero. The computation of earnings to fixed charges is set forth on Exhibit 12.1 to the registration statement of which this prospectus forms a part.

Ratio of earnings to fixed charges is calculated by dividing earnings by fixed charges from operations for the periods indicated. For purposes of calculating the ratio of earnings to fixed charges, (a) earnings represents pre-tax income from continuing operations plus fixed charges and amortization of capitalized interest, less capitalized interest and (b) fixed charges represents interest expensed and capitalized, amortization of financing costs, early extinguishment of debt and the portion of rent expense deemed to be the equivalent of interest.

You should read the ratio information below in conjunction with the Management s Discussion and Analysis of Financial Condition and Results of Operations and the financial statements and the notes thereto included elsewhere in this prospectus.

	For the Three Months Ended March 31,		For the Years Ended December 31, (in thousands)				
	2008	2007	2007	2006	2005	2004	2003
Loss (deficiency with fixed charges)	$ (1,277)	$ (10,955)	$ (32,392)	$ (84,839)	$ (25,692)	$ (12,776)	$ (4,947)
Ratio of earnings to fixed charges							

USE OF PROCEEDS

The exchange offer is intended to satisfy our obligations under the registration rights agreement we entered into in connection with the issuance of the old notes. We will not receive any cash proceeds from the issuance of the new notes in the exchange offer. In consideration for issuing the new notes as contemplated in this prospectus, we will receive in exchange outstanding old notes in like principal amount. We will cancel all old notes surrendered in exchange for new notes in the exchange offer. As a result, the issuance of the new notes will not result in any increase or decrease in our indebtedness.

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THE EXCHANGE OFFER

Purpose and Effect of the Exchange Offer

We sold $100.0 million in aggregate principal amount at maturity of the old notes, which was completed on November 29, 2007. The old notes were sold to investors in a private placement in the United States in reliance on Section 4(2) and/or Regulation D of the Securities Act or to the initial purchasers who in turn resold the outstanding notes to offshore investors pursuant to Regulation S of the Securities Act.

We sold the old notes in transactions that were exempt from or not subject to the registration requirements under the Securities Act. Accordingly, the old notes are subject to transfer restrictions. In general, you may not offer or sell the old notes unless either the offer and sale thereof are registered under the Securities Act or are exempt from or not subject to registration under the Securities Act and applicable state securities laws.

In the registration rights agreement, we agreed to file an exchange offer registration statement no later than 150 days after the closing date following the offering of the old notes. We also agreed to use our commercially reasonable best efforts to cause the exchange offer registration statement for the new notes to become effective within 240 days after the closing date. Now, to satisfy our obligations under the registration rights agreement, we are offering holders of the old notes who are able to make certain representations described below the opportunity to exchange their notes for the new notes in the exchange offer. The exchange offer will be open for a period of at least 30 days. During the exchange offer period, we will issue the new notes in exchange for all old notes properly surrendered and not withdrawn before the expiration date. The new notes will be registered and the transfer restrictions, registration rights and provisions for additional interest relating to the old notes will not apply to the new notes.

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Terms of Exchange

Subject to the terms and conditions described in this prospectus and in the letter of transmittal, we will accept for exchange any old notes properly tendered and not withdrawn prior to 5:00 p.m., New York City time, on the expiration date of the exchange offer. We will issue new notes in principal amount equal to the principal amount of old notes surrendered in the exchange offer. Old notes may be tendered only for new notes and only in denominations of $2,000 and integral multiples of $1,000.

The exchange offer is not conditioned upon any minimum aggregate principal amount of old notes being tendered in the exchange offer.

As of the date of this prospectus, $100,000,000 in aggregate principal amount of 12¾% Senior Secured Notes due 2012 are outstanding. This prospectus is being sent to DTC, the sole registered holder of the old notes, and to all persons that we can identify as beneficial owners of the old notes. There will be no fixed record date for determining registered holders of old notes entitled to participate in the exchange offer.

We intend to conduct the exchange offer in accordance with the provisions of the registration rights agreement, the applicable requirements of the Securities Act and the Securities Exchange Act of 1934, as amended, or the Exchange Act, and the rules and regulations of the Commission. Old notes the holders of which do not tender for exchange in the exchange offer will remain outstanding and continue to accrue interest. These old notes will be entitled to the rights and benefits such holders have under the indenture relating to the old notes and the registration rights agreement.

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We will be deemed to have accepted for exchange properly tendered old notes when we have given oral or written notice of the acceptance to the exchange agent and complied with the applicable provisions of the registration rights agreement. The exchange agent will act as agent for the tendering holders for the purposes of receiving the new notes from us.

If you tender old notes in the exchange offer, you will not be required to pay brokerage commissions or fees or, except to the extent indicated by the instructions to the letter of transmittal, transfer taxes with respect to the exchange of old notes. We will pay all charges and expenses, other than certain applicable taxes described below, in connection with the exchange offer. Please read Fees and Expenses for more details regarding fees and expenses incurred in connection with the exchange offer. We will return any old notes that we do not accept for exchange for any reason without expense to their tendering holders promptly after the expiration or termination of the exchange offer.

Expiration, Extension and Amendment

The exchange offer will expire at 5:00 p.m., New York City time, on , 2008, unless, in our sole discretion, we extend it.

We expressly reserve the right, at any time or various times, to extend the period of time during which the exchange offer is open. We may delay acceptance of any old notes by giving oral or written notice of such extension to their holders at any time until the exchange offer expires or terminates. During any such extensions, all old notes previously tendered will remain subject to the exchange offer, and we may accept them for exchange.

To extend the exchange offer, we will notify the exchange agent orally or in writing of any extension. We will notify the registered holders of old notes of the extension no later than 9:00 a.m. New York City time on the business day after the previously scheduled expiration date.

Procedures for Tendering

To participate in the exchange offer, you must properly tender your old notes to the exchange agent as described below. We will only issue new notes in exchange for old notes that you timely and properly tender. Therefore, you should allow sufficient time to ensure timely delivery of the old notes, and you should follow carefully the instructions on how to tender your old notes. It is your responsibility to properly tender your old notes. We have the right to waive any defects. We are not, however, required to waive defects, and neither we nor the exchange agent is required to notify you of any defects in your tender.

If you have any questions or need help in exchanging your old notes, please call the exchange agent whose address and phone number are described in the letter of transmittal included as Annex A to this prospectus.

All of the old notes were issued in book entry form, and all of the old notes are currently represented by global certificates registered in the name of Cede & Co., the nominee of DTC. We have confirmed with DTC that the old notes may be tendered using ATOP. The exchange agent will establish an account with DTC for purposes of the exchange offer promptly after the commencement of the exchange offer, and DTC participants may electronically transmit their acceptance of the exchange offer by causing DTC to transfer their old notes to the exchange agent using the ATOP procedures. In connection with the transfer, DTC will send an agent s message to the exchange agent. The agent s message will state that DTC has received instructions from the participant to tender old notes and that the participant agrees to be bound by the terms of the letter of transmittal.

By using the ATOP procedures to exchange old notes, you will not be required to deliver a letter of transmittal to the exchange agent. You will, however, be bound by its terms just as if you had signed it.

There is no procedure for guaranteed late delivery of the old notes.

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Determinations Under the Exchange Offer. We will determine in our sole discretion all questions as to the validity, form, eligibility, time of receipt, acceptance of tendered old notes and withdrawal of tendered old notes. Our determination will be final and binding. We reserve the absolute right to reject any old notes not properly tendered or any old notes our acceptance of which would, in the opinion of our counsel, be unlawful. We also reserve the right to waive any defect, irregularities or conditions of tender as to particular old notes. Our interpretation of the terms and conditions of the exchange offer, including the instructions in the letter of transmittal, will be final and binding on all parties. Unless waived, all defects or irregularities in connection with tenders of old notes must be cured within such time as we shall determine. Although we intend to notify holders of defects or irregularities with respect to tenders of old notes, neither we, the exchange agent nor any other person will incur any liability for failure to give such notification. Tenders of old notes will not be deemed made until such defects or irregularities have been cured or waived. Any old notes received by the exchange agent that are not properly tendered and as to which the defects or irregularities have not been cured or waived will be returned to the tendering holder as soon as practicable following the expiration date of the exchange.

When We Will Issue New Notes. In all cases, we will issue new notes for old notes that we have accepted for exchange under the exchange offer only after the exchange agent receives, prior to 5:00 p.m., New York City time, on the expiration date,

- A book-entry confirmation of such old notes into the exchange agent s account at DTC; and

- A properly transmitted agent s message.

Return of Old notes Not Accepted or Exchanged. If we do not accept any tendered old notes for exchange or if old notes are submitted for a greater principal amount than the holder desires to exchange, the unaccepted or non exchanged old notes will be returned without expense to their tendering holder. Such non exchanged old notes will be credited to an account maintained with DTC. These actions will occur as promptly as practicable after the expiration or termination of the exchange offer.

Valid Tender. By agreeing to be bound by the letter of transmittal, you will represent to us that, among other things:

- Any new notes that you receive will be acquired in the ordinary course of your business;

- You have no arrangement or understanding with any person or entity to participate in the distribution of the new notes;

- You are not engaged in and do not intend to engage in the distribution of the new notes;

- If you are a broker-dealer that will receive new notes for your own account in exchange for old notes, you acquired those old notes as a result of market-making activities or other trading activities and you will deliver this prospectus, as required by law, in connection with any resale of the new notes; and

- You are not an affiliate, as defined in Rule 405 under the Securities Act, of us.

Withdrawal Rights

Except as otherwise provided in this prospectus, you may withdraw your tender at any time prior to 5:00 p.m., New York City time, on the expiration date of the exchange offer. For a withdrawal to be effective you must comply with the appropriate ATOP procedures. Any notice of withdrawal must specify the name and number of the account at DTC to be credited with withdrawn old notes and otherwise comply with the ATOP procedures.

We will determine all questions as to the validity, form, eligibility and time of receipt of a notice of withdrawal. Our determination shall be final and binding on all parties. We will deem any old notes so withdrawn not to have been validly tendered for exchange for purposes of the exchange offer.

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Any old notes that have been tendered for exchange but that are not exchanged for any reason will be credited to an account maintained with DTC for the old notes. This return or crediting will take place as soon as practicable after withdrawal, rejection of tender, expiration or termination of the exchange offer. You may retender properly withdrawn old notes by following the procedures described under Procedures for Tendering above at any time on or prior to the expiration date of the exchange offer.

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Resales of New Notes

Based on interpretations by the staff of the SEC, as described in no-action letters issued to third parties that are not related to us, we believe that new notes issued in the exchange offer in exchange for old notes may be offered for resale, resold or otherwise transferred by holders of the new notes without compliance with the registration and prospectus delivery provisions of the Securities Act, if:

- The new notes are acquired in the ordinary course of the holder s business;
- The holders have no arrangement or understanding with any person to participate in the distribution of the new notes;
- The holders are not affiliates of ours within the meaning of Rule 405 under the Securities Act; and
- The holders are not a broker-dealer who purchased old notes directly from us for resale pursuant to Rule 144A or any other available exemption under the Securities Act.

However, the SEC has not considered the exchange offer described in this prospectus in the context of a no-action letter. The staff of the SEC may not make a similar determination with respect to the exchange offer as in the other circumstances. Each holder who wishes to exchange old notes for new notes will be required to represent that it meets the above four requirements.

Any holder who is an affiliate of ours or who intends to participate in the exchange offer for the purpose of distributing new notes or any broker-dealer who purchased old notes directly from us for resale pursuant to Rule 144A or any other available exemption under the Securities Act:

- Cannot rely on the applicable interpretations of the staff of the SEC mentioned above;
- Will not be permitted or entitled to tender the old notes in the exchange offer; and
- Must comply with the registration and prospectus delivery requirements of the Securities Act in connection with any secondary resale transaction.

Each broker-dealer that receives new notes for its own account in exchange for old notes must acknowledge that the old notes were acquired by it as a result of market-making activities or other trading activities and agree that it will deliver a prospectus that meets the requirements of the Securities Act in connection with any resale of the new notes. The letter of transmittal states that by so acknowledging and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an underwriter within the meaning of the Securities Act. Please read Plan of Distribution . A broker-dealer may use this prospectus, as it may be amended or supplemented from time to time, in connection with the resales of new notes received in exchange for old notes that the broker-dealer acquired as a result of market-making or other trading activities. Any holder that is a broker-dealer participating in the exchange offer must notify the exchange agent at the telephone number set forth in the enclosed letter of transmittal and must comply with the procedures for broker-dealers participating in the exchange offer. We have not entered into any arrangement or understanding with any person to distribute the new notes to be received in the exchange offer.

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In addition, to comply with state securities laws, the new notes may not be offered or sold in any state unless they have been registered or qualified for sale in such state or an exemption from registration or qualification, with which there has been compliance, is available. The offer and sale of the new notes to qualified institutional buyers, as defined under Rule 144A of the Securities Act, is generally exempt from registration or qualification under the state securities laws. We currently do not intend to register or qualify the sale of new notes in any state where an exemption from registration or qualification is required and not available.

Exchange Agent

Wells Fargo Bank, National Association has been appointed as the exchange agent for the exchange offer. Questions and requests for assistance, requests for additional copies of this prospectus or of the letter of transmittal should be directed to the exchange agent addressed as follows:

Wells Fargo Bank, National Association

By Facsimile for Eligible Institutions:
(214) 777-4086
Attention: Patrick T. Giordano

By Registered and Certified Mail:
Wells Fargo Bank, NA
Corporate Trust Operations
MAC N9303-121
PO Box 1517
Minneapolis, MN 55480

By Regular Mail or Overnight Courier:
Wells Fargo Bank, NA
Corporate Trust Operations
MAC N9303-121
Sixth & Marquette Avenue

Minneapolis, MN 55479

In person by hand only:
Wells Fargo Bank, NA
12th Floor - Northstar East Building
Corporate Trust Operations
608 Second Avenue South

Minneapolis, MN

Confirm by Telephone:
(214) 740-1573

Fees and Expenses

We will bear the expenses of soliciting tenders. The principal solicitation is being made by mail; however, we may make additional solicitation by telegraph, telephone or in person by our officers and regular employees and those of our affiliates.

We have not retained any dealer manager in connection with the exchange offer and will not make any payments to broker dealers or others soliciting acceptances of the exchange offer. We will, however, pay the exchange agent reasonable and customary fees for its services and reimburse it for its related reasonable out of pocket expenses.

We will pay the cash expenses to be incurred in connection with the exchange offer. They include:

Commission registration fees;

Fees and expenses of the exchange agent and trustee;

Accounting and legal fees and printing costs; and

Related fees and expenses.

Transfer Taxes

We will pay all transfer taxes, if any, applicable to the exchange of old notes under the exchange offer. Each tendering holder, however, will be required to pay any transfer taxes, whether imposed on the registered holder or any other person, if a transfer tax is imposed for any reason other than the exchange of old notes under the exchange offer.

Consequences of Failure to Exchange Outstanding Securities

If you do not exchange your old notes for new notes under the exchange offer, the old notes you hold will continue to be subject to the existing restrictions on transfer. In general, you may not offer or sell the old notes except under an exemption from, or in a transaction not subject to, the Securities Act and applicable state securities laws. We do not intend to register old notes under the Securities Act unless the registration rights agreement requires us to do so.

Accounting Treatment

We will record the new notes in our accounting records at the same carrying value as the old notes. This carrying value is the aggregate principal amount of the old notes, as reflected in our accounting records on the date of exchange. Accordingly, we will not recognize any gain or loss for accounting purposes in connection with the exchange offer, other than the recognition of the fees and expenses of the offering as stated under Fees and Expenses.

Other

Participation in the exchange offer is voluntary, and you should consider carefully whether to accept. You are urged to consult your financial and tax advisors in making your own decision on what action to take.

We may in the future seek to acquire untendered old notes in open market or privately negotiated transactions, through subsequent exchange offers or otherwise. We have no present plans to acquire any old notes that are not tendered in the exchange offer or to file a registration statement to permit resales of any untendered old notes.

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CAUTIONARY STATEMENTS REGARDING FORWARD-LOOKING STATEMENTS

This prospectus and the documents incorporated contain or incorporate by reference forward-looking statements within the meaning of Section 27A of the Securities Act, and Section 21E of the Exchange Act. Forward-looking statements give our current expectations or forecasts of future events. 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 words. 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;
- Demand 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 inherent to the natural gas and oil business;

Down hole 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;

Adverse weather conditions;

Availability and cost of material and equipment, such as drilling rigs and transportation pipelines;

The number of well locations to be drilled and the time frame in which they will be drilled;

Delays in anticipated start-up dates;

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

Ability to find and retain skilled personnel;

Strength and financial resources of competitors;

Potential defects in title to our properties;

Federal and state regulatory developments and approvals;

Losses possible from pending or future litigation;

- Environmental risks;

- Worldwide political and economic conditions; and

- Operational and financial risks associated with foreign exploration and production.

For these and other reasons, actual results may differ materially from those projected or implied. We believe it is important to communicate our expectations of future performance to our investors. However, events may occur in the future that we are unable to accurately predict, or over which we have no control. We caution you against putting undue reliance on forward-looking statements or projecting any future results based on such statements.

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All subsequent written and oral forward-looking statements attributable to us or any person acting on our behalf are expressly qualified in their entirety by the cautionary statements contained or referred to in this section and any other cautionary statements that may accompany such forward-looking statements. We do not undertake any obligation to release publicly any revisions to these forward-looking statements to reflect events or circumstances after the date of this prospectus or to reflect the occurrence of unanticipated events, unless the securities laws require us to do so.

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SELECTED HISTORICAL CONSOLIDATED FINANCIAL DATA

The following tables set forth selected historical consolidated financial data for the three month ended March 31, 2008 and 2007 and for the years ended December 31, 2007, 2006, 2005, 2004 and 2003. The historical financial data as of December 31, 2007 and 2006 and for the years ended December 31, 2007, 2006 and 2005 are derived from our audited consolidated financial statements and the notes thereto included in this prospectus. The unaudited condensed consolidated balance sheet data and statement of operations data at March 31, 2007 and 2008 and for the three month periods ended March 31, 2007 and 2008 are derived from our unaudited condensed combined financial statements and the notes thereto included in this prospectus. The historical financial data as of December 31, 2005, 2004 and 2003 and for the years ended December 31, 2004 and 2003 are derived from our audited consolidated financial statements which are not included in this prospectus. The selected financial data should be read in conjunction with, and is qualified in its entirety by reference to, Management s Discussion and Analysis of Financial Condition and Results of Operations and our financial statements and the notes thereto included elsewhere in this prospectus.

	For the Three Months Ended March 31,		For the Years Ended December 31,				
	2008	2007	2007	2006	2005	2004	2003
	(unaudited)		(in thousands, except per share and share amounts)				
Revenues:							
Natural gas and oil revenues	$ 16,846	$ 7,515	$ 34,565	$ 26,765	$ 27,442	$ 6,059	$ 1,461
Unrealized natural gas hedge loss	(1,413)						
Expenses:	15,433	7,515	34,565	26,765	27,442	6,059	1,461
Lease operating expenses, production taxes and transportation and treating	2,270	2,312	8,690	8,584	6,910	2,000	712
Depreciation, depletion and amortization	6,409	4,341	21,456	16,332	13,914	3,233	572
Impairment of natural gas and oil properties			28,514	56,280	8,697	6,306	552
Accretion of asset retirement obligation	82	66	281	234	109	52	54
Mineral resource properties		13	(133)	450	65	32	30
General and administrative expenses	4,275	6,792	16,906	13,548	8,710	4,023	1,909
Litigation and settlement expenses		1,365	1,365	2,407			
Total expenses	13,036	14,889	77,079	97,835	38,405	15,646	3,829
Income (loss) from operations	2,397	(7,374)	(42,514)	(71,070)	(10,963)	(9,587)	(2,368)
Other (expenses) income:							
Interest expense	(2,096)	(3,943)	(14,079)	(15,599)	(13,905)	(3,248)	(2,567)
Early extinguishment of debt			(15,684)		(1,356)		
Investment income and other	823	363	3,196	1,836	492	56	18
Gain on sale of assets			38,536				
Foreign transaction gain (loss)	(37)	(1)	5	(6)	40	3	91
INCOME (LOSS) BEFORE INCOME TAXES	1,087	(10,955)	(30,540)	(84,839)	(25,692)	(12,776)	(4,826)
Provision for income taxes							
NET INCOME (LOSS) BEFORE CUMULATIVE EFFECT OF A CHANGE IN ACCOUNTING PRINCIPLE	1,087	(10,955)	(30,540)	(84,839)	(25,692)	(12,776)	(4,826)

Cumulative effect of a change in accounting principle							(121)
NET INCOME (LOSS)	$ 1,087	$ (10,955)	$ (30,540)	$ (84,839)	$ (25,692)	$ (12,776)	$ (4,947)
NET INCOME (LOSS) PER SHARE:							
Basic and diluted	$ 0.01	$ (0.06)	$ (0.15)	$ (0.50)	$ (0.20)	$ (0.12)	$ (0.05)
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:							
Basic and diluted	207,098,570	195,015,561	202,828,792	170,014,733	129,398,548	111,374,446	104,958,180

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	As of and for the Three Months Ended March 31, 2008	2007	As of and for the Years Ended December 31, 2007	2006	2005	2004	2003
	(unaudited)			(in thousands)			
Statements of Cash Flow Data:							
Capital expenditures	$ 19,957	$ 18,389	$ 64,841	$ 50,215	$ 33,287	$ 34,221	$ 4,763
Net cash provided by (used in):							
Operating activities	14,292	281	7,442	(1,281)	3,380	(1,122)	(2,447)
Investing activities	(21,183)	(18,404)	(3,467)	(66,949)	(77,833)	(36,062)	2,585
Financing activities	5	(1)	41,146	47,819	119,755	52,345	283
Balance Sheet Data:							
Cash and cash equivalents	$ 78,968	$ 22,609	$ 85,854	$ 40,733	$ 61,144	$ 15,842	$ 681
Property, plant and equipment, net	167,358	180,607	157,120	160,826	165,347	56,564	35,799
Total assets	268,285	226,608	261,750	228,889	240,128	84,442	38,757
Total debt	132,715	94,607	132,685	93,803	90,631	57,878	6,562
Shareholders equity	93,160	89,230	95,269	98,342	120,776	21,976	23,669

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MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL

CONDITION AND RESULTS OF OPERATIONS

You should read this discussion in conjunction with our audited and unaudited consolidated financial statements and the related notes beginning on page F-1 of this prospectus. Management s discussion and analysis may contain forward looking statements that are provided to assist in the understanding of anticipated future financial performance. However, this performance involves risks and uncertainties that may cause actual results to differ materially from these expressed in the forward looking statements. Some of the important factors that could cause our actual results or outcomes to differ from those discussed are listed under Cautionary Statements Regarding Forward-Looking Statements .

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 CBM. We are also pursuing unconventional natural gas exploration in the deep Bossier play in the Hilltop area in East Texas. Our primary CBM properties are in the United States in the Powder River Basin in Wyoming and Montana and in the Gunnedah and Gippsland Basins of Australia.

Our major domestic asset is approximately 35,400 gross (16,300 net) acres in the Bossier play in the Hilltop area of East Texas. During the past three years, we spent approximately $196.6 million in acreage, seismic and reserve acquisition and exploratory and development drilling on this acreage. While we have not attained positive net income from operations in the past three years, and there can be no assurance that operating income and net earnings will be achieved in future periods, our recent efforts have resulted in significant growth in production over the past three-year period. As we continue the exploitation and development drilling in the Hilltop area, we expect to show further improvement in our operations.

Our international activities are focused on CBM development in Australia on over 6.0 million gross (2.1 million net) acres in New South Wales. We are in the early stages of development of this potentially significant asset, which could have a material and positive long-term impact on our financial results. Although we currently have no commercial production, we and our joint venture partner have been approached by potential buyers with an interest in potentially contracting for future deliveries of natural gas from PEL 238 for use in the generation of electricity. In September 2007, NSA certified a quantity of proved and probable reserves under guidelines established by the Society of Petroleum Engineers (SPE), as a result of the success of one of our pilot production projects on PEL 238. These reserves, however, are not yet established as proved reserves under SEC guidelines nor can we assure that other unevaluated acreage will contain similar reserves.

Our financial results depend upon many factors which significantly affect our results of operations including the following:

- The level and success of exploration and development activity;
- The sales prices of natural gas and crude oil;
- The level of total sales volumes of natural gas and crude oil; and
- The availability of and our ability to raise the capital necessary to meet our cash flow and liquidity needs.

We plan our activities and budget based on conservative sales price assumptions, given the inherent volatility of natural gas and oil prices that are influenced by many factors beyond our control. We focus our efforts on increasing natural gas and oil reserves and production and strive to control costs at an appropriate level. Our future earnings and cash flows are dependent on our ability to manage our overall cost structure to a level that allows for profitable production. Our future earnings will also be impacted by the changes in the fair market value of hedges we executed to mitigate the volatility in the changes of natural gas and oil prices in future periods. These instruments meet the criteria to be accounted for as cash flow hedges, and until settlement, the changes in fair

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market value of our hedges will be included as a component of stockholder s equity to the extent effective in periods of rising prices, these transactions will mitigate future earnings and in periods of declining prices will increase future earnings in the respective period the positions are settled.

Like other natural gas and oil exploration and production companies, we face the fact of natural production declines. As initial reservoir pressures are depleted, natural gas and oil production from a given well will decrease. Thus, a natural gas and oil exploration and production company depletes part of its asset base with each unit of natural gas and oil it produces. We attempt to overcome this natural decline by adding reserves in excess of what we produce through successful drilling or acquisition. Our future growth will depend on our ability to continue to add reserves in excess of our production. We will maintain our focus on adding reserves through drilling and acquisitions, while placing a clear priority on lowering our cost of replacing reserves. Consistent with our stated strategies, we will emphasize maintaining a high-quality inventory of drilling locations, while also focusing on improving our capital and cost efficiency.

Results of Operations

The following is a comparative discussion of the results of operations for the periods indicated. It should be read in conjunction with the consolidated financial statements and the related notes to the consolidated financial statements.

The following table gives information about production volumes and prices of natural gas and oil for the periods indicated:

	For the Three Months Ended March 31,		For the Years Ended December 31,		
	2008	2007	2007	2006	2005
Production:					
Natural gas (MMcf)	2,406	1,253	6,577	4,646	3,810
Oil (MBbl)	1	3	7	12	2
Total (MMcfe)	2,413	1,272	6,621	4,716	3,822
Total (MMcfed)	26.5	14.1	18.1	12.9	10.5
Average sales prices:					
Natural gas (per Mcf)	$ 6.96	$ 5.86	$ 5.18	$ 5.60	$ 7.18
Oil (per Bbl)	$ 96.84	$ 55.05	$ 66.17	$ 64.66	$ 50.85

Three Months Ended March 31, 2008 compared to the Three Months Ended March 31, 2007

Revenues. Substantially all of our revenues are derived from the production of natural gas in the United States. Natural gas and oil revenues were $16.8 million for the three months ended March 31, 2008, up 124% from $7.5 million for the three months ended March 31, 2007. Of the increase in revenues, 72% was the result of a 88% increase in natural gas production volumes, primarily in East Texas, and 28% was due to a 19% increase in prices. During the three months ended March 31, 2008, approximately 44% of our natural gas production was hedged. The realized effect of hedging on natural gas sales was a decrease of $232,000 in revenues resulting in a decrease in total price received from $7.05 per Mcf to $6.96 per Mcf.

Unrealized natural gas hedge loss of $1.4 million is comprised of $169,000 of ineffectiveness and $1.2 million related to the time value of the costless collars. For the remainder of 2008, we have approximately 50% of our estimated gas production hedged.

Production taxes. We reported production taxes of $269,000 for the three months ended March 31, 2008, compared to $294,000 for the three months ended March 31, 2007. The lower overall production tax level is the result of refunds and abatements of severance taxes due to tight sands production on certain of our Hilltop wells.

Lease operating expenses. We reported lease operating expenses of $1.5 million for the three months ended March 31, 2008, down from $1.7 million for the three months ended March 31, 2007. Our lease operating expenses were $0.64 per Mcfe for the three months ended March 31, 2008, compared to $1.33 per Mcfe for the comparable period in 2007. This decrease was due to lower ad valorem taxes, workover expense and the elimination of lease costs associated with natural gas treatment plants in East Texas. This decrease was partially offset by an increased number of producing wells and increased production.

Transportation and treating. We reported transportation expenses of $459,000 for the three months ended March 31, 2008, up from 323,000 for the three months ended March 31, 2007. This increase was primarily due to increased production and prices in Wyoming.

Depreciation, depletion and amortization. We reported depreciation, depletion and amortization (DD&A) of $6.4 million for the three months ended March 31, 2008, up from $4.3 million for the three months ended March 31, 2007. The increase in DD&A expense was the result of a 90% increase in production, primarily attributable to new East Texas wells drilled during 2007. The DD&A rate for the three months ended March 31, 2008 was $2.66 per Mcfe, as compared to $3.41 for the comparable period in 2007.

General and administrative. We reported general and administrative expenses of $4.3 million for the three months ended March 31, 2008, down from $6.8 million for the three months ended March 31, 2007. This decrease in general and administrative expenses was primarily due to an allowance for doubtful accounts of $3.6 million recorded in the three months ended March 31, 2007, which was partially offset by an increase in professional service charges, including legal costs and personnel costs. Non-cash stock-based compensation expense pursuant to the SFAS 123R, which is included in general and administrative expenses, was $856,000 and $1.2 million for the three months ended March 31, 2008 and 2007, respectively.

Litigation settlement expense. The $1.4 million litigation settlement expense incurred in the three months ended March 31, 2007 was primarily the result of an accrual related to a proposed settlement with GeoStar on certain matters, which has not been settled. There was no litigation settlement expense for the three months ended March 31, 2008.

Interest expense. We reported interest expense of $2.1 million for the three months ended March 31, 2008, compared to $3.9 million for the three months ended March 31, 2007. The decrease in interest expense was primarily the result of $2.4 million of interest being capitalized during the three months ended March 31, 2008, resulting from capital activity expansion in Texas and Australia, which was partially offset by higher interest expense on the new 12¾% senior secured notes. There was no capitalized interest recorded in the 2007 period.

Year Ended December 31, 2007 compared to Year Ended December 31, 2006

Revenues. Substantially all of our revenues are derived from the production of natural gas in the United States. Revenues were $34.6 million for the year ended December 31, 2007, up 29% from $26.8 million for the year ended December 31, 2006. The increase in revenues was the result of a 42% increase in natural gas production primarily in East Texas, which was partially offset by an 8% decrease in natural gas prices.

Production taxes. We reported production taxes of $765,000 for the year ended December 31, 2007, down from $1.5 million for the year ended December 31, 2006. This decrease was the result of tight sand credit refunds on our Texas natural gas sales and lower Wyoming taxes due to gas price declines.

Lease operating expenses. We reported lease operating expenses of $6.3 million for the year ended December 31, 2007, up from $5.5 million for the year ended December 31, 2006. This increase was due to an increased number of producing wells and increased production. Our lease operating expenses were $0.95 per Mcfe for the year ended December 31, 2007, compared to $1.18 per Mcfe for the comparable period in 2006.

Transportation and treating. We reported transportation expenses of $1.6 million for the years ended December 31, 2007 and 2006. Transportation and treating expense was constant as it relates to our Powder River Basin CBM production, which did not change significantly from 2006.

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Depreciation, depletion and amortization. Depreciation, depletion and amortization was $21.5 million for the year ended December 31, 2007, up from $16.3 million for the year ended December 31, 2006. The increase in DD&A expense was the result of a 40% increase in production, primarily attributable to new East Texas wells drilled during 2007. The DD&A rate for the year ended December 31, 2007 was $3.22 per Mcfe, as compared to $3.44 for the comparable period in 2006.

Impairment of natural gas and oil properties. Impairment of U.S. natural gas and oil properties was $28.5 million for the year ended December 31, 2007, compared to $56.3 million for the comparable period ended December 31, 2006. The 2007 impairment is the result of net natural gas and oil property costs, as adjusted for related deferred income taxes, if any, and other adjustments, exceeding the sum of estimated future net revenues using weighted average after basis adjustment prices in effect at June 30, 2007, the date of the impairment, held constant at $5.72 per Mcf for natural gas, discounted at 10%, and unproven properties at historical costs of $43.6 million. The 2006 impairment was 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 post end of period weighted average after basis adjustment prices held constant of $6.11 per Mcf for natural gas, discounted at 10%, and unproven property at historical cost of $81.5 million, as adjusted for related income taxes and other adjustments.

General and administrative. We reported general and administrative expenses of $16.9 million for the year ended December 31, 2007, up from $13.5 million for the year ended December 31, 2006. This increase in general and administrative expenses was primarily due to an increase in allowance for doubtful accounts and professional service charges, including Sarbanes-Oxley compliance costs, partially offset by a decline in contract personnel costs. The allowance for doubtful accounts was increased by $3.7 million to fully reserve the GeoStar receivable due to current litigation. Non-cash stock-based compensation expense pursuant to the SFAS 123R, which is included in general and administrative expenses, was $3.9 million for both years ended December 31, 2007 and 2006.

Litigation settlement expense. The $1.4 million litigation settlement expense incurred in 2007 was primarily the result of an accrual of a settlement payment related to a proposed settlement with GeoStar on certain matters. The settlement proposal was never finalized (Note 16 Commitments and Contingencies Litigation Arbitration and Litigation with GeoStar Corporation and Affiliates). The $2.4 million litigation settlement expense incurred in 2006 was primarily the result of a settlement payment regarding Western Gas Resources, Inc., *et. al*. litigation involving a gas gathering agreement and its applicability to properties we exchanged in 2002 and settlement of the Burning Rock Energy LLC, *et. al.* litigation by assigning our interest in certain disputed properties.

Interest expense. We reported interest expense of $14.1 million for the year ended December 31, 2006, compared to $15.6 million for the year ended December 31, 2006. The decrease in interest expense was primarily the result of $1.9 million of capitalized interest in 2007, resulting from capital activity expansion in Texas and Australia. Interest expense includes deferred cost and debt discount amortization of $4.2 million for 2007, a decrease of $100,000 from the comparable 2006 period. There was no capitalized interest in 2006

Debt extinguishment expense. We reported debt extinguishment expense of $15.7 million for the year ended December 31, 2007. This resulted from the expensing of a prepayment penalty of $3.7 million and deferred financing and debt discount costs of $12.0 million incurred related to $73.0 million of senior secured notes. The senior secured notes were repaid prior to maturity with the proceeds from the sale of $100.0 million of 12 $^{3}/4$% Senior Secured Notes in November 2007. There was no debt extinguishment expense in 2006.

Year Ended December 31, 2006 compared to Year Ended December 31, 2005

Revenues. Substantially all of our revenues are derived from the production of natural gas in the United States. Revenues were $26.8 million for the year ended December 31, 2006, down from $27.4 million for the year ended December 31, 2005. The decrease in revenues was the result of a 21% decrease in natural gas prices, which was partially offset by a 23% increase in production.

Production taxes. We reported production taxes of $1.5 million for the year ended December 31, 2006, up from $1.1 million for the year ended December 31, 2005. This increase was the result of increased production from new wells and a $350,000 tight sands gas tax refund in 2005.

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Lease operating expenses. We reported lease operating expenses of $5.5 million for the year ended December 31, 2006, up from $3.9 million for the year ended December 31, 2005. This increase was due to an increase in the number of producing wells. Our lease operating expenses were $1.18 per Mcfe for the year ended December 31, 2006, compared to $1.01 per Mcfe for the comparable period in 2005.

Transportation and treating. We reported transportation expenses of $1.6 million for the year ended December 31, 2006, down from $2.0 million for the year ended December 31, 2005. The decrease in expense was primarily the result of lower Powder River Basin transportation costs. This decrease was the result of a decrease in per Mcf cost from $1.43 per Mcf in 2005 to $0.88 per Mcf in 2006.

Depreciation, depletion and amortization. Depreciation, depletion and amortization was $16.3 million for the year ended December 31, 2006, up from $13.9 million for the year ended December 31, 2005. This increase primarily was attributable to new East Texas wells drilled and placed into production during 2006 and additional production from new CBM wells drilled in the Powder River Basin. The increase in DD&A expense was the result of a 23% increase in production, which was partially offset by a 5% decrease in the DD&A rate per unit of production. The DD&A rate for the year ended December 31, 2006 was $3.44 per Mcfe, as compared to $3.63 for the comparable period in 2005.

Impairment of natural gas and oil properties. Impairment of U.S. natural gas and oil properties was $56.3 million for the year ended December 31, 2006, compared to $8.7 million for the comparable period ended 2005. The 2006 impairment was 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 post end of period weighted average after basis adjustment prices held constant of $6.11 per Mcf for natural gas, discounted at 10%, and unproven property at historical cost of $81.5 million, which was lower than the estimated fair market value, as adjusted for related income taxes and other adjustments. The 2005 impairment was the result of net natural gas and oil property costs, as adjusted for related deferred income taxes, if any, and other adjustments, exceeding the sum of estimated future net revenues using prices in effect at June 30, 2005, the date of the impairment, held constant at $5.32 per Mcf for natural gas, discounted at 10%, and unproven properties at historical costs of $93.3 million, as adjusted for related deferred income taxes and other adjustments.

General and administrative. We reported general and administrative expenses of $13.5 million for the year ended December 31, 2006, up from $8.7 million for the year ended December 31, 2005. This increase in general and administrative expenses was primarily due to increases in staff, contract personnel and professional service charges, and the recording of non-cash compensation expense due to the granting of stock options. Non-cash stock-based compensation expense for 2006 pursuant to the SFAS 123R, which is included in general and administrative expenses, was $3.9 million, up from $2.3 million in 2005.

Litigation settlement expense. The $2.4 million litigation settlement expense incurred in 2006 was primarily the result of a settlement payment regarding Western Gas Resources, Inc., *et. al*., of a lawsuit involving a gas gathering agreement and its applicability to properties we exchanged in 2002 and settlement of the Burning Rock Energy LLC, *et. al.* litigation by assigning our interest in certain disputed properties. There was no litigation settlement expense in 2005.

Interest expense. We reported interest expense of $15.6 million for the year ended December 31, 2006, compared to $13.9 million for the year ended December 31, 2005. The increase in interest expense was the result of higher average debt outstanding and higher interest rates. Interest expense includes deferred financing cost and debt discount amortization of $4.3 million for 2006, a decrease of $500,000 from 2005.

Debt extinguishment expense. In June 2005, in conjunction with the issuance of the senior secured notes, the Company retired certain senior secured notes, resulting in a debt extinguishment expense of $1.4 million, comprised of $662,000 of early prepayment penalty and $694,000 of unamortized deferred financing costs.

Liquidity and Capital Resources

At March 31, 2008, we had cash and cash equivalents of $79.0 million and $16.9 million of borrowing availability under our bank revolving credit facility. For the three months ended March 31, 2008, we reported cash flow from operations of $14.3 million, up from $281,000 of cash flow from operations for the three months ended March 31, 2007. This increase resulted primarily from a 88% increase in production volumes and a 19% increase in prices. Capital expenditures on natural gas and oil properties totaled $20.0 million for the three months ended March 31, 2008.

Covenants in our 12¾% Senior Secured Notes Indenture, our indenture governing our 9.75% convertible senior unsecured subordinated debentures and our Revolving Credit Facility agreement require us to make an offer to repurchase or repay all of the outstanding indebtedness thereunder in the event of a change of control of the Company, as defined in the respective agreements. Each of the indentures provides that if there is a change of control of the Company, as defined in the respective indenture, we are required to make an offer to each holder to repurchase all or any part of the 12¾% Senior Secured Notes or the 9.75% convertible senior unsecured subordinated debentures, as the case may be, at 101% of the aggregate principal amount of the notes or debentures tendered for repurchase, plus accrued and unpaid interest. In the event of a change of control, as defined under the Revolving Credit Facility Agreement, all obligations under the Revolving Credit Facility will become immediately due and payable. If the change of control event occurs in one or more of these agreements, we may not have adequate financing available to meet the resulting payment obligations.

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 and Australia, additional funds will be needed for acreage acquisition, seismic and other geologic analysis, drilling, undertaking completion activities and for general corporate purposes. 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, corporate overhead and expenditures associated with our projected drilling and development activities. We expect to fund these expenditures from internally generated cash flow, cash on hand, sales of assets and the issuance of additional debt or equity. We may also attempt to balance future capital expenditures through joint venture development of certain properties with industry partners. We cannot be certain that future funds will be available to fully execute our current business plan.

Our 2008 capital expenditures under our business plan are estimated to total approximately $65.4 million, of which $43.4 million is estimated to be spent on unconventional natural gas and oil exploration and development operations in East Texas, $7.4 million is estimated to be spent on CBM projects and additional projects in the United States and $14.6 million is estimated to be spent on CBM projects in Australia. Based on our current budget, we have sufficient capital, together with internally generated cash flow, to fund our exploration and development activities in East Texas and Australia for 2008 and a significant portion of our 2009 projected capital needs.

Our cash flow and ability to raise capital are highly dependent upon natural gas pricing. A material decrease in current and projected natural gas prices could impact our ability to fund future activities, impair our ability to raise additional capital on acceptable terms and result in a financial covenant default under the 12¾% Senior Secured Notes, resulting in mandatory principal reduction under certain conditions. It may be difficult for us to raise capital through the issuance of common shares due to the pending GeoStar litigation.

In the fourth quarter of 2007 and the first quarter of 2008, we entered into various costless collar transactions with counterparties. The volumes currently hedged represents approximately 50% of 2008 and 15% of 2009 projected production.

Covenants in our 12¾% Senior Secured Notes Indenture and our Revolving Credit Facility Agreement restrict us from hedging more than 75% of the projected production from proved developed producing reserves.

At March 31, 2008, we were in compliance with all debt covenants.

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Contractual Obligations

The following table summarizes our future contractual obligations under these arrangements as of December 31, 2007:

	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
			(in thousands)		
Maturities on long-term debt, including related current portion (1)	$ 133,250	$	$ 33,250	$ 100,000	$
Interest on long-term debt	67,934	16,008	28,540	23,386	$
Office lease (2)	582	205	377		$
Drilling contract (3)	12,060	6,300	5,760		$
Operating leases and other (4)	25	8	17		$
Total	$ 213,851	$ 22,521	$ 67,944	$ 123,386	$

(1) These amounts represent the principal balances that will become due on our 12 $^{3}/4$% Senior Secured Notes, subordinated unsecured notes payable and convertible senior debenture.
(2) Office lease obligation expires October 31, 2010.
(3) Represents minimum rates under a three year drilling contract commitment requiring minimum fees per year, net of advance payments.
(4) Represents operating lease payments for various office equipment.

We maintain a reserve for cost associated with the retirement of tangible long-lived assets. At December 31, 2007, our reserve for these obligations totaled $4.4 million for which no contractual commitment exists. Information about this reserve is set forth in Note 2 Summary of Significant Accounting Policies Asset Retirement Obligation to our consolidated financial statements, which begin on page F-1.

We have employment agreements with our Chief Executive Officer, Chief Financial Officer and Chief operating Officer, which obligate us to pay a specified level of salary, target bonus and certain other payments and reimbursements to them during their employment and in the event of termination or change of control. Information about such payments is set forth in Executive Compensation .

Commitments

During 2006, we entered into an agreement with a drilling contractor to provide contracted drilling services in the Hilltop area of East Texas for a three-year period at agreed upon day rates. The Company made advance payments totaling $2.0 million prior to drilling rig delivery in November 2006. The advance payments are being amortized over the three-year term of the agreement. The Company is required to pay the drilling contractor a minimum of $6.3 million per year in drilling day rate fees, net of the amortization of the advance payments, during the three-year term of the agreement commencing November 2006.

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In March 2008, we entered into formal agreements with ETC Texas Pipeline, Ltd. (ETC) for the gathering, treating, purchase and transportation of our natural gas production from Hilltop area of East Texas. These agreements are effective September 1, 2007 and have a term of 10 years. ETC currently provides us 50 MMcfd of treating capacity and 120 MMcfd of gathering capacity. We have the right to request ETC build, at their cost, up to 150 MMcfd of treating and gathering capacity during the term of the agreement, provided that our production equals 85% of the then existing treating and gathering capacity for a 30 day period. We may at any time elect to have our treating and gathering capacity increased subject to cost indemnifications to ETC. Additional treating and gathering capacity requests must be in at least 25 MMcfd and 5 MMcfd increments, respectively. In addition, we must furnish to ETC information that reasonably demonstrates that our projected production for the five years after expansion is sufficient to warrant the costs to create the expanded treating and gathering capacity. The incremental volume increases in treating and gathering capacity shall be subject to marginal increases in treating fees. Pursuant to the agreements, we have access up to 150 MMcfd of firm transportation on ETC s system or the pipelines of its affiliates or subsidiaries from the tailgate of the treating facility to Katy Hub. We have the option to sell and ETC has the obligation to buy, up to 150 MMcfd of our Hilltop production at delivery points upstream of ETC s gathering and treating facilities. We do not have an obligation to deliver to ETC volumes in excess of 150 MMcfd, but should ETC elect to purchase such excess volumes, purchases will be subject to the treating and gathering expansion terms set forth in the agreements.

Registration Obligation and Penalties

On November 29, 2007, Gastar USA, a wholly owned subsidiary of Gastar Exploration Ltd., sold $100.0 million aggregate principal amount of 12 3/4% Senior Secured Notes at an issue price of 99.50%. Gastar USA is obligated to prepare and file with the SEC within 150 days of the issue date of the 12 3/4% Senior Secured Notes, or April 27, 2008, a registration statement to exchange the 12 3/4% Senior Secured Notes for registered, publicly tradable notes that have substantially identical terms as the 12 3/4% Senior Secured Notes. Gastar USA is to use its best efforts to cause the registration statement to be declared effective within 240 day of the issue date of the 12 3/4% Senior Secured Notes, or July 24, 2008. Gastar USA has agreed to offer new notes in exchange for the 12 3/4% Senior Secured Notes as soon as is practicable after the registration statement has become effective, unless prohibited by law or SEC policy, and to file a shelf registration statement for the resale of the 12 3/4% Senior Secured Notes if Gastar USA cannot consummate the exchange offer within 290 days of the date of the issuance of the 12 3/4% Senior Secured Notes, or September 12, 2008, and in certain other circumstances. In the event Gastar USA fails to meet its registration obligations as set forth above, Gastar USA has agreed to pay liquidated damages to the holders of the 12 3/4% Senior Secured Notes in the form of additional cash interest payments on the 12 3/4% Senior Secured Notes equal to 0.25% per annum for the first 90-day period, increasing to a maximum of 0.50% per annum for each subsequent 90-day period.

New Accounting Pronouncements

Fair Value Measurements. In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157*,* Fair Value Measurements (SFAS No. 157), which addresses how companies should measure fair value when companies are required to use a fair value measure for recognition or disclosure purposes under US GAAP. As a result of SFAS No. 157 there is now a common definition of fair value to be used throughout US GAAP. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those years. The FASB also has issued Staff Position FAS 157-2 (FSP No. 157-2), which delays the effective date of SFAS No. 157 for nonfinancial assets and liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until fiscal years beginning after November 15, 2008. Effective January 1, 2008, the Company adopted SFAS 157 and has chosen to defer the implementation of nonfinancial assets and liabilities in accordance with FSP FAS No. 157-2. The effect of adoption in January 1, 2008 was immaterial to the Company s financial position. The adoption of FSP FAS No. 157-2 is not expected to have a material impact on the Company s results of operations, cash flows or financial positions. See Note 10, Fair Value Measurements for additional information regarding the adoption of SFAS No. 157.

Non-controlling Interests in Consolidated Financial Statements. In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements, an amendment of Accounting Research Bulletin No. 51 (SFAS No. 160), which improves the relevance, comparability and transparency of the

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financial information that a reporting entity provides in its consolidated financial statements by establishing accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. This statement is effective for fiscal years beginning after December 15, 2008. The Company does not expect the adoption of SFAS No. 160 to have a material impact on the Company s consolidated financial position, results of operations or cash flows.

Business Combinations. In December 2007, FASB issued SFAS No. 141, Business Combinations (SFAS No. 141R), which creates greater consistency in the accounting and financial reporting of business combinations. This statement is effective for fiscal years beginning after December 15, 2008. The Company does not expect the adoption of SFAS No. 141R to have a material impact on the Company s consolidated financial position, results of operations or cash flows.

The Fair Value Option for Financial Assets and Financial Liabilities. In February 2007, FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115 (SFAS No159), which permits an entity to choose to measure certain financial assets and liabilities at fair value. SFAS No. 159 also revises provisions of SFAS No. 115 that apply to available-for-sale and trading securities. This statement is effective for fiscal years beginning after November 15, 2007. The Company does not expect the adoption of SFAS No. 159 to have a material impact on the Company s consolidated financial position, results of operations or cash flows.

Commodity Price 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. We have entered into hedge transactions to mitigate our commodity pricing risk. For the three months ended March 31, 2008, a 10% change in the prices received for natural gas production would have had an approximate $1.7 million impact on our revenues before mitigating factors that might result from having hedge transactions in place. See Note 5 to our condensed consolidated financial statements for additional information on our hedging activities.

Interest Rate Risk

The carrying value of our debt approximates fair value. At March 31, 2008, we had approximately $133.3 million in principal amount of long-term debt, all of which was at a fixed interest rate. A 10% fluctuation in interest rates would have no impact on annual interest expense.

Currency Translation Risk

Our revenues and expenses and the majority of our capital expenditures are primarily in U.S. dollars, thus limiting our exposure to currency translation risk. During the three months ended March 31, 2008, we spent approximately $860,000 of capital expenditures on our Australian activities. We have no plans in the foreseeable future to implement hedges or financial instruments to manage international currency changes.

Management s Report on Internal Control over Financial Reporting

The Company s management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Under the supervision and with the participation of management, including the principal executive officer and principal financial officer, the Company conducted an evaluation of the effectiveness of the Company s internal control over financial reporting based on the framework in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Our internal control over financial reporting includes policies and procedures that (1) pertain to maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures are being made only in accordance with authorizations of our management and board of directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of assets that could have a material effect on the financial statements.

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Due to its inherent limitations, internal control over financial reporting may not prevent or detect misstatements and, even when determined to be effective, can only provide reasonable, not absolute, assurance with respect to financial statement preparation and presentation. Projections of any evaluation of effectiveness to future periods are subject to risk that controls may become inadequate as a result of changes in conditions or deterioration in the degree of compliance.

Based on the assessment, our management has concluded that our internal control over financial reporting was effective as of December 31, 2007 and provides reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes in accordance with generally accepted accounting principles. The results of management s assessment were reviewed with the Audit Committee of our Board of Directors.

Our internal control over financial reporting has been audited by BDO Seidman, LLP, an independent registered public accounting firm, as stated in their report which is included herein.

/s/ J. RUSSELL PORTER
J. Russell Porter
Chairman, President and Chief Executive Officer
March 17, 2008

/s/ MICHAEL A. GERLICH
Michael A. Gerlich
Vice President and Chief Financial Officer
March 17, 2008

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Report of Independent Registered Public Accounting Firm

Board of Directors and Shareholders

Gastar Exploration Ltd.

Houston, Texas

We have audited Gastar Exploration Ltd. s (the Company) internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO Criteria). The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Item 9A, Management s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the effectiveness of internal control over financial reporting of the Company based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Gastar Exploration Ltd. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the COSO Criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Gastar Exploration Ltd. and subsidiaries as of December 31, 2007 and 2006 and the related consolidated statements of operations, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2007 and our report dated March 14, 2008 expressed an unqualified opinion thereon.

/s/ BDO Seidman, LLP

Dallas, Texas
March 14, 2008

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Off-Balance Sheet Arrangements

As of December 31, 2007, we had no off-balance sheet arrangements. We have no plans to enter into any off-balance sheet arrangements in the foreseeable future.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America (US GAAP) 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 consolidated 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 are uncertain at the time the estimate is 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.

Full Cost Method of Accounting

We follow the full cost method of accounting for natural gas and oil operations, whereby all costs incurred in the acquisition, exploration and development of natural gas and oil reserves are initially capitalized into cost centers on a country-by-country basis. Our current cost centers are located in the United States and Australia. Such costs include land acquisition costs, geological and geophysical expenditures, carrying charges on non-producing properties, costs of drilling and overhead charges directly related to acquisition, exploration and development activities.

Costs capitalized, together with the costs of production equipment, are depleted and amortized on the unit-of-production method based on the estimated net proved reserves, as determined by independent petroleum engineers. The percentage of total reserve volumes produced during the year is multiplied by the net capitalized investment plus future estimated development costs in those reserves.

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

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

Natural Gas and Oil Reserves

Nature of Critical Estimate Item. Our estimate of proved reserves is based on the quantities of natural gas and oil 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

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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.

Ceiling Limitation Test The full cost method of accounting for natural gas and oil 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 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 natural gas and oil properties is not reversible at a later date even if natural gas and oil prices increase. Impairments were required at December 31, 2006 and at June 30, 2007. 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, but subsequent period end prices may be used if such prices would reduce the ceiling impairment. 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 at the time of evaluation. The weighted average natural gas after basis adjustments used in the reserve valuations as of December 31, 2006 and June 30,2007 were $6.12 per Mcf and $5.72 per Mcf, respectively.

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 December 31, 2007, we had a ceiling impairment cushion of $45.2 million. A 10% decrease in prices would have resulted in a decrease in the cushion of approximately $24.1 million. A 10% increase in prices used would have resulted in an increase in the cushion approximately $20.7 million.

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

Effect if different assumptions used. A 10% increase in reserves would have decreased our depletion expense for the year ended December 31, 2007 by approximately 2%, while a 10% decrease in reserves would have increased our depletion expense by approximately 3%.

Unproved Property Impairment

Nature of Critical Estimate Item. We have elected to use the full cost method to account for our natural gas and oil 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 natural gas and oil property costs to be amortized.

Assumptions/Approach Used. At December 31, 2007, we had $46.5 million allocated to unproved United States property costs which was comprised primarily of unevaluated acreage costs. 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 decreased or increased our depletion expense by approximately 1% for the year ended December 31, 2007.

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Asset Retirement Obligation

Nature of Critical Estimate Item. We have certain obligations to remove tangible equipment and restore land at the end of natural gas and oil production operations. Our removal and restoration obligations are primarily associated with plugging and abandoning wells. Under Statement of Financial Accounting Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations , as discussed in Note 2 to our consolidated financial statements, we 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 asset retirement obligation, or ARO, liability in that amount with a corresponding addition to our capitalized cost. 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 independent petroleum engineers, who have consented to the use of their name and reports in this Prospectus, to evaluate our properties annually. We primarily 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 as an estimate based on field or industry practices. We expect to see our calculations impacted significantly if interest rates move from their current levels, 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.

Capitalized Interest

We capitalize interest for two purposes: (1) capitalized interest on funds borrowed for specific projects, such as our long-term development of our CBM assets in New South Wales and Victoria, Australia and (2) capitalized interest on borrowed funds used to invest in unproven natural gas and oil properties not being amortized. The methodology for capitalizing interest on general funds, consistent with SFAS No. 34, Capitalization of Interest Cost, begins with a determination of the borrowings applicable to our qualifying assets. The basis of this approach is the assumption that the portion of the interest costs that are capitalized on expenditures during an asset s acquisition period could have been avoided if the expenditures had not been made. This methodology takes the view that if funds are not required for construction then they would have been used to pay off other debt. We use our best judgment in determining which borrowings represent the cost of financing the acquisition of the assets. The primary debt instruments included in the rate calculation of interest incurred on the funds is our 12 $^{3}/4$% Senior Secured Notes. The interest to be capitalized for any period is derived by multiplying this fixed rate of interest times the average qualifying assets during the period. To qualify for interest capitalization, we must continue to make progress on the development of the assets.

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Stock-Based Compensation

Nature of Critical Estimate Item. Effective January 1, 2003, we adopted the provisions of SFAS No. 123, Accounting for Stock-Based Compensation (SFAS No. 123), using the prospective application method of SFAS No. 148, Accounting for Stock-Based Compensation Transition and Disclosure . This statement required us to record compensation costs for options granted under our stock option plan in accordance with the fair value method prescribed in SFAS No. 123.

Effective January 1, 2006, we adopted the fair value recognition provisions of SFAS 123R, Share-Based Payment , using the modified-prospective method. Under that method, compensation cost for 2007 and 2006 includes: (a) compensation cost for all share-based payments granted prior to, but not yet vested as of, January 1, 2006, based on the grant date fair value estimated in accordance with the original provisions of SFAS No. 123, and (b) compensation cost for all share-based payments granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS 123R.

The Company reports compensation expense for stock options and restricted common shares granted to officers, directors and employees using the fair value method in accordance with SFAS 123R. Stock-based compensation costs are recorded over the requisite service period, which approximates the vesting period.

The fair value of each stock option grant is estimated on the date of grant using the Black-Scholes-Merton valuation pricing model. The fair value of all awards is expensed using the graded-vesting method , which recognizes compensation costs over the requisite service period for each separately vesting tranche of an award as though the award were, in substance, multiple awards.

Assumption/Approach Used. The Black-Scholes-Merton model requires various highly judgmental assumptions including volatility, expected option life and forfeiture rate. If any of the assumptions used in the Black-Scholes-Merton model change significantly, stock-based compensation expense may differ materially in the future from that recorded in the current period. The table below summarizes the key assumptions for the stock options granted for the periods indicated:

	For the Years Ended December 31,	
	2007	**2006**
Expected volatility	44.4-44.7%	45.7%
Expected life (in years)	6.25	6.5
Expected forfeitures	5.0%	5.0%

Effect if different assumptions used. A 10% increase or decrease in the volatility rate would increase or decrease our stock based compensation for the year ended December 31, 2007 by approximately 6.4% and 6.6%, respectively. A 10% increase or decrease in expected life would increase or decrease our stock based compensation expense for the year ended December 31, 2007 by approximately 4.6% and 4.9%, respectively. A 10% increase or decrease in forfeiture rate would have a corresponding impact on our stock based compensation expense for the year ended December 31, 2007.

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BUSINESS

Our Company

We are a Houston, Texas-based independent natural gas and oil company engaged in the exploration, development and production of natural gas and oil in the United States and Australia. Our domestic drilling activities are focused on exploiting our multi-year inventory of drilling locations in the deep Bossier sands and Knowles Limestone plays of East Texas and in the Powder River Basin of Wyoming. Our operations in Australia are focused on the development of CBM rights in New South Wales and Victoria, Australia. We believe that our dual focus enables us to generate high initial production and long-lived producing wells with strong cash flow dynamics from our East Texas activities while also providing us with significant reserve upside through the development of our Australian resource plays. Gastar USA is a Michigan corporation. Our parent, Gastar Exploration Ltd., a Canadian corporation incorporated in Alberta, is a publicly traded company listed on the American Stock Exchange under the ticker symbol GST and on the Toronto Stock Exchange under the ticker symbol YGA with an equity market capitalization of $369 million and CDN $360 million, respectively, as of May 1, 2008.

The majority of our domestic portfolio is located on acreage in established geological trends where we utilize our engineering, operating, geologic and geophysical expertise to provide significant proved reserve and production growth with attractive returns on investment. The current focus of these activities is in the Hilltop area of East Texas, where we currently hold a total of approximately 37,500 gross (16,500 net) acres of oil and gas leaseholds. Our production in East Texas is characterized by prolific initial production rates that decline in the first year into a more stable long-term productive profile. Typically wells in the deep Bossier generate approximately 25 to 35% of their production in the first 12 months and have a reserve life ranging from 8 to 12 years. To date, we have drilled and completed 16 of 17 East Texas wells, including the successful completion of all 10 wells drilled since the end of 2005.

Our ability to apply information learned with the drilling of each of our wells to the drilling of subsequent wells has enabled us to significantly improve the drilling and completion costs of our newer East Texas wells. Based on estimates from our independent petroleum engineers, our eight deep Bossier wells completed in 2006 and 2007 have improved average proved reserves over their economic lives to 4.3 Bcf gross (2.3 Bcf net) from 2.0 Bcf gross (1.5 Bcf net) for all of our previous drilling. During these same periods our average per well drilling and completion costs improved to $14.3 million gross from $15.6 million gross. As a result of our early drilling we recognized that the deep Bossier series of sands is productive in high structural positions with favorable porosity and permeability characteristics within the reservoir. We then recognized that the deposition of slightly younger Bossier sands is dependent upon their position relative to faulting within the Bossier section. As a result of these and other derived information, we drilled the Donelson #3 well (our most recent Bossier completion) which generated peak production of 24.0 MMcfc/d and which our engineers estimate will produce approximately 10.9 Bcf gross (5.5 Bcf net) of proved reserves over its economic life. Our cost to drill and complete the Donelson #3 was $12.6 million gross ($8.4 million net). Following the spudding of the Donelson #3, we completed the processing and interpretation of the new 3-D seismic data which covers 100% of our East Texas acreage. We believe that our increased understanding of the depositional geologic model for the Bossier, combined with the new 3-D seismic data and a drilling strategy over the next two years focusing on offset locations to the Donelson #3, will enhance our ability to find optimal drilling locations. We have identified 115 additional drilling locations (64 net) across our acreage for this formation.

Since early 2006, we drilled three wells in the Knowles Limestone, which NSA estimates will average 1.9 Bcf gross (0.7 Bcf net) of proved reserves over their economic life. We believe that production and ultimate recoveries from existing and future Knowles Limestone wells may be enhanced through the use of a relatively inexpensive well stimulation process. We believe we can further improve our well economics by using our recently acquired 3-D seismic survey, covering 100% of our Knowles Limestone acreage. We have identified 20 additional drilling locations (11 net) across our acreage for this formation.

In addition to our exploitation and production activities in East Texas, the exploration and development of our CBM assets in Australia has the potential for significant reserve and production growth. We own a 35% working interest in each of three petroleum exploration licenses, PEL 238, PEL 433 and PEL 434, in the Gunnedah Basin of New South Wales and a 75% working interest in an exploration license, EL 4416, in the Gippsland Basin in Victoria, Australia. These licenses include over 7.0 million gross (2.9 million net) acres. During 2008, we intend to

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expand our pilot production drilling program on the PEL 238 concession working with Eastern Star Gas Limited (ASX:ESG), our working interest partner and license operator. Through our planned development program in PEL 238, consisting of additional production pilot projects and core hole drilling, we intend to convert a portion of the significant resource potential into certifiable proved and probable reserves as we move towards commercial production. The certification of proved reserves and the growth of our probable reserves is necessary to support the development of infrastructure to service growing natural gas demand in New South Wales. Contracts for the construction of this infrastructure, as well as gas sales or use contracts, are not expected until late 2008 and will be required before recognition of significant proved reserves in PEL 238 under SEC guidelines. Eastern Star Gas Limited owns a 65% interest in PEL 238. On December 31, 2007, Eastern Star Gas Limited had an equity market capitalization of approximately USD $350 million.

In the United States, our CBM activities are located in the Powder River Basin in Wyoming where our development and recompletion activities provide us with a stable base of production. At December 31, 2007, we held an approximate 40% average working interest in approximately 55,000 gross (21,900 net) leasehold acres and an ownership interest in 283 gross (125.2 net) productive economic CBM wells.

NSA has estimated our total domestic proved reserves as of December 31, 2007, to be 54.9 Bcfe under SEC definition and guidelines, consisting almost entirely of natural gas.

Natural Gas and Oil Activities

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

Hilltop Area, East Texas

Hilltop Area, East Texas. The majority of our activities has been in the deep Bossier play in the Hilltop area, located in East Texas approximately midway between Dallas and Houston in Leon and Robertson Counties. This exploration play has attracted some of the largest and most active operators in the U.S. Wells in this area target multiple potentially productive natural gas formations and are typically characterized by high initial production, significant decline rates and long-lived reserves.

Our first successful operated well was spudded in 2003 and placed on production in September 2004. As of December 31, 2007, we had successfully completed 14 out of 15 deep Bossier wells and four out of four Knowles Limestone wells. During 2007, we drilled and successfully completed a total of five gross (3.0 net) Bossier wells and three gross (1.5 net) Knowles Limestone wells.

In May 2007, we sold a portion of our undeveloped natural gas and oil acreage in the Hilltop area of East Texas for approximately $66.5 million, net of transaction costs of approximately $1.2 million, resulting in a gain on sale of $38.5 million. We currently have a total of approximately 35,400 gross (16,300 net) acres in the Bossier play. In July 2007, we completed the processing of a 3-D seismic survey purchased earlier in the year. This survey covered all of our retained undeveloped acreage position and is being interpreted and used in the selection of our drilling locations. For 2008, we plan to drill up to three deep Bossier wells and four Knowles Limestone wells.

In early 2008, we drilled the Holmes #1 well to a total depth of 18,700 feet and, based on drilling, core and log analysis, encountered one Bossier sand that will be completed for production. The well is scheduled to be completed and placed on production in mid-May 2008. The Holmes #1 is an immediate offset to the successful F-K #1 well.

We are drilling the Lone Oak Ranch #6 well (LOR #6) to target middle Bossier sands. The LOR #6 is currently drilling at 13,774 feet and is expected to reach total depth in early June. The LOR #6 is being drilled using slim-hole casing design at an estimated cost of $8.0 million to drill and complete the well. We are also side-tracking the LOR #4 well horizontal section in order to re-complete the well using a strata-pack system that will allow for multiple acid fracture stimulations of the Knowles Limestone pay zones. The LOR #4 was originally completed as an open-hole well with no acid fracture stimulation.

We drilled the Brunette #1, a horizontal Knowles Limestone well, to a total measured depth of 15,251 feet (total vertical depth of 13,341 feet). The well encountered approximately 640 feet of reservoir quality formation within the 1,367-foot horizontal section of the wellbore. The Brunette #1 was stimulated and placed on production in mid-April 2008 and is flowing at a gross stabilized rate of 1.0 MMcf per day. Several mechanical issues were encountered in the completion of the Brunette #1 well that appear to be restricting the sales rate. We will monitor well performance for approximately 60 days before implementing any remedial operations to further enhance production.

For the year ended December 31, 2007, net production from the Hilltop area averaged 13.0 MMcf per day, For the three months ended March 31, 2008, net production from the Hilltop area averaged 20.9 MMcf per day, up approximately 40% from 15.0 MMcf per day for the fourth quarter on 2007 and up approximately 121% from 9.5 MMcf per day for the three months ended March 31, 2007.

For the balance of 2008, Gastar anticipates a two-rig drilling program in East Texas with one rig dedicated to drilling deep Bossier wells and the second rig dedicated to drilling horizontal Knowles Limestone wells.

Coalbed Methane Powder River Basin, Wyoming and Montana

We own an approximate 40% average working interest in approximately 55,000 gross (21,900 net) acres in the Powder River Basin of Wyoming and Montana. The Powder River Basin has been an important natural gas producing area for nearly 100 years. Generally, CBM wells are shallow and less costly than conventional natural gas wells. Our primary areas of activity in the Powder River Basin are the Squaw Creek, Ring of Fire and adjacent fields, all of which are located north of Gillette, Wyoming in an active drilling area.

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During 2007, we participated in the drilling of approximately 27 (12.5 net) CBM wells. As of December 31, 2007, we had an interest in 283 gross (125.2 net) productive CBM wells producing in the Basin. For the year ended December 31, 2007, our average net production from our CBM properties in the Powder River Basin was approximately 5.1 MMcf per day. We anticipate continuing our recompletion and drilling program in 2008. Our activity level will be influenced by regional natural gas prices, which remained lower than its historic prices relative to Gulf Coast Henry Hub natural gas prices during late 2007. Regional prices in early 2008 have rebounded to, or above, historic price levels.

For the three months ended March 31, 2008, our average net production form our CBM properties in the Powder River Basin was approximately 5.6 MMcf per day.

Coalbed Methane   PEL 238, Gunnedah Basin, New South Wales, Australia

We have a 35% interest in PEL 238, a CBM exploratory property covering approximately 2.2 million gross (786,000 net) acres, located in the Gunnedah Basin of New South Wales, approximately 250 miles northwest of Sydney, Australia, near the town of Narrabri. We believe that the strategic location of the properties and potential CBM reserves near the large natural gas markets in the Sydney-Newcastle-Wollongong area and the concession s location relative to other developing gas markets should create a competitive marketing advantage for the natural gas reserves that may be developed on PEL 238.

Extensive coring of the coal on PEL 238 by the Australian government has provided a thorough understanding of the coal resources and potential CBM resource in place on our license. Two primary coal seams are found on the PEL 238 license, the Late Permian aged Hoskisson coal formation and the Early Permian aged Maules Creek coal formation.

During 2006, we participated with our joint venture partner and license operator, Eastern Star Gas Limited, in the drilling of eight new vertical coal seam natural gas wells on approximately 40-acre spacing in close proximity to an existing well within the Bohena Project Area of PEL 238 and one additional monitoring well. The results from the pilot production phase of the program have been positive, with the results confirming the high measured permeability of the coal and the presence of natural gas in the coal.

During 2007, we and our joint venture partner were approached by potential buyers with an interest in potentially contracting for up to 1 Tcf of natural gas from PEL 238. In March 2007, we announced that we and our joint venture partner had executed a Memorandum of Understanding (MOU) with Macquarie Generation, a New South Wales government-owned electricity generator, for the potential future supply of natural gas for its Bayswater power station. Macquarie Generation is Australia s largest electricity producer and owns and operates two coal fired power stations in the Hunter Valley-Bayswater and Liddell. A long-term natural gas supply and purchase agreement with Macquarie Generation could include up to 500 Bcf to be delivered over a 15 to 20 year period commencing in late 2010, though there is no assurance that such an agreement will ultimately be reached or that such volumes will ultimately be produced from PEL 238. In addition, a potential gas supply and purchase agreement with Macquarie Generation would serve to underpin the development of the approximately 300 kilometers of pipeline infrastructure necessary to transport gas from the PEL 238 concession to Bayswater. An additional 150 kilometers of pipeline infrastructure would be required to access the natural gas markets of Sydney-Newcastle-Wollongong area.

In November 2007, we announced that we and our joint venture partner had entered into a second MOU with Babcock & Brown (Babcock & Brown MOU) to supply gas from the PEL 238 and PEL 433 concessions for use in the generation of electricity. The Babcock & Brown MOU envisions the supply of up to 30 Bcf per year of natural gas from the Gunnedah Gas Project to be delivered over multiple years for use in a gas fueled power station to be developed by Babcock & Brown in northern New South Wales, Australia commencing in late 2010. Natural gas sales under the anticipated agreements could be expanded to meet requirements for power station developments at other locations, though there is no assurance that such an agreement will ultimately be reached or that such volumes will ultimately be produced from the PEL 238 and PEL 433 concessions.

In September 2007, NSA certified a quantity of proved and probable reserves under guidelines established by the Society of Petroleum Engineers (SPE), as a result of the success of one of our pilot production projects on PEL 238. These reserves, however, are not yet established as proved reserves under SEC guidelines nor can we assure that other unevaluated acreage will contain similar reserves.

Petroleum Assessment Lease 2, or PAL 2, was issued by the New South Wales Department of Primary Industries on October 30, 2007. PAL 2, in which Gastar holds a 35% interest, lies within PEL 238 and covers the

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existing Bohena Project Area of approximately 65,000 gross acres including the Bibblewindi and Bohena Production Pilots, with umbilical areas connecting to the Wilga Park Power Station. The assessment lease, which is intended for the area to be assessed for an eventual production lease, allows gas production from the two production pilots to ultimately be transported by a dedicated gas gathering system to the power station for electricity production and sale. We and our joint venture partner are in the permitting phase for the construction of the gathering system and pipeline, which is anticipated to be completed by late 2008.

Beginning in 2008, we and our joint venture partner have expanded our pilot production drilling program on the PEL 238 concession and recently successfully completed the drilling of the first test corehole, the Dewhurst #2, in a 20-well exploration and appraisal corehole drilling program on PEL 238. The results of the Dewhurst #2 confirmed the presence of a thick Bohena coal seam developed to the south and east of the Bibblewindi pilot production area. The Dewhurst #2 encountered approximately 39 meters of coal within the Black Jack and Maules Creek coal formations, including approximately 18.2 meters in the targeted Bohena seam of which 14.7 meters was found in a single coal zone. We have commenced drilling the second test corehole of the 2008 gas reserves upgrade program, the Dewhurst #3, which is located approximately 2.2 miles east of the Dewhurst #2.

The area on which PEL 238 is located is subject to a native title claim lodged in March 2007 by the Gomeroi Narrabri People (NSD437/07). See Governmental Regulation-Australian Governmental Regulation-Native Title .

Coal Bed Methane PEL 433-434, Gunnedah Basin, New South Wales, Australia

PEL 433 is located south of PEL 238 where Gastar and our joint venture partner, Eastern Star Gas Limited, are developing the Gunnedah Basin Gas Project (Coal Seam Gas Joint Venture). Coal evaluation core-hole drilling completed during the 1970s and 1980s by the New South Wales government identified the distribution and thickness of the coal measures within a portion of PEL 433. The Hoskissons Coal Seam is believed to be approximately 4 to 6 meters thick and widely distributed within the eastern part of PEL 433. There has been no previous coal seam gas exploration and evaluation work in the area, and there is no information on gas content, gas composition or coal permeability.

In July 2007, we entered into a Farm-In Agreement with Eastern Star Gas Limited under which we have earned a 35% working interest in the PEL 433 and adjoining PEL 434 properties. Under the terms of the Farm-In Agreement, we paid the costs of a two core-hole program and the related costs of the evaluation of the coal reservoirs intersected by the core-holes. The two corehole drilling program commenced during July 2007 and evaluated the coal seam gas potential of the Hoskissons Coal Seam within the Late Permian Black Jack Coal Measures. Additional coring may be undertaken on PEL 433 to provide additional data on coal depth, thickness, permeability, gas contents and composition.

The area believed to be the most prospective for coal seam gas within PEL 433 underlies and is in close proximity to the Central Ranges Natural Gas Pipeline that links Dubbo with Tamworth and joins with the larger Moomba-Sydney Gas Pipeline. This gas pipeline would enable gas sales within the region and potentially in Sydney and surrounding markets.

The area on which PEL 433 is located is subject to a native title claim lodged in June 2002 by the Tubba-Gah People (NSD6010/02). See Governmental Regulation-Australian Governmental Regulation-Native Title .

Coalbed Methane EL 4416, Gippsland Basin, Victoria, Australia

We have a 75% interest in the CBM rights in EL 4416, an approximate 1.0 million gross (750,000 net) acre property covering a substantial part of the onshore portion of the Gippsland Basin of Victoria, Australia, located approximately 130 miles east of Melbourne. The EL 4416 property is well situated with three existing natural gas transmission lines running through the license area from productive offshore fields to a large natural gas processing facility and then to markets near Sydney, Melbourne and in Tasmania. The EL 4416 coal is classified as low-rank brown coal. The Victorian government has extensively evaluated the potential coal resources through detailed coal resource studies. Due to our large acreage position and the fact that this thick coal is present over a large percentage of the license area, the CBM resource potential is believed to be significant.

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During 2006, we began initial long-term testing of the first of two wells completed on EL 4416. Before a pump failure, early water production had been significant, indicating permeability in the targeted coal seam. In late 2006, we pre-funded $6.5 million for a 10-well drilling program, which commenced drilling operations in late 2006. The program included the establishment of two five-spot pilots, one incorporating two existing wells and two wells designed to test for the presence and production potential of the coal at additional locations within the license area. In one of the two previously drilled wells, we have installed larger capacity pumps to facilitate de-watering operations.

Prior to the completion of the 10-well program mentioned above, Gastar and the operator of EL 4416, a subsidiary of GeoStar Corporation (GeoStar), became involved in a number of disputes concerning Gastar s right to an assignment of its interest in EL 4416 and other jointly-owned properties. As a result, the operator has not provided Gastar with information concerning the results of the 10-well drilling program nor an accounting for the use of the funds provided for the drilling of the 10 CBM wells. While we believe we have good beneficial title to our interest in EL 4416, the subsidiary of GeoStar has not delivered to us a title assignment of our interest in a form to be recorded with Australian government officials. We have sent a letter to GeoStar demanding the arbitration of these issues. See Legal Proceedings Arbitration and Litigation with GeoStar Corporation and Affiliates .

No native title claims have been lodged at this time in relation to the area on which EL 4416 is located. See Governmental Regulation Australian Governmental Regulation Native Title .

Production, Prices and Operating Expenses

The following table presents information regarding the production volumes, average sales prices received and average production costs associated with our sales of natural gas and oil for the years ended December 31, 2007 and 2006. Oil and condensate are compared with natural gas in terms of cubic feet of natural gas equivalents. One barrel of oil or condensate is the energy equivalent of six Mcf of natural gas.

	For the Three Months Ended		For the Years Ended December 31,	
	2008	**2007**	**2007**	**2006**
Production:				
Natural gas (MMcf)	2,406	1,253	6,576	4,646
Oil (MBbl)	1	3	8	12
Total (MMcfe)	2,413	1,272	6,621	4,716
Total (MMcfed)	26.5	14.1	18.1	12.9
Average sales prices:				
Natural gas (per Mcf), including impact of realized hedging activities	$ 6.96	$ 5.86	$ 5.18	$ 5.60
Oil (per Bbl)	$ 96.84	$ 55.05	$ 66.17	$ 64.66
Selected data per Mcfe:				
Lease operating, transportation and selling expenses	$ 0.94	$ 1.81	$ 1.32	$ 1.82
General and administrative expenses	$ 1.77	$ 2.50	$ 2.13	$ 2.87
Depreciation, depletion and amortization of natural gas and oil properties	$ 2.66	$ 3.41	$ 3.24	$ 3.46

Drilling Activity

The following table shows our drilling activity for the periods indicated. In the table, gross wells refer to wells in which we have a working interest, and net wells refer to gross wells multiplied by our working interest in such wells. Undecided wells are CBM 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.

	For the Years Ended December 31,			
	2007		**2006**	
	Gross	**Net**	**Gross**	**Net**
Exploratory wells:				
Productive	4	2.2	4	2.3

Non-productive	1	0.3	1	0.3
Under evaluation	10	7.5	9	3.2
Total	15	10.0	14	5.8
Development wells:				
Productive	31	14.8	43	19.5
Non-productive				
Total	31	14.8	43	19.5

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Exploration and Development Acreage

The following table sets forth our ownership interest in undeveloped and developed acreage in the areas indicated where we own a working interest as of December 31, 2007. Gross represents the total number of acres in which we own a working interest. Net represents our proportionate working interest resulting from our ownership in gross acres.

	Undeveloped Acreage		Developed Acreage	
	Gross	Net	Gross	Net
Hilltop area, East Texas	28,494	12,144	6,942	4,106
Powder River Basin, Wyoming and Montana	33,917	11,992	21,049	9,862
Other	7,017	5,782		
Total United States	69,428	29,918	27,991	13,968
Gunnedah Basin, New South Wales	6,047,150	2,116,503	2,200	770
Gippsland Basin, Victoria	1,000,000	750,000		
Total Australia	7,047,150	2,866,503	2,200	770

Productive Wells

The following table sets forth our working interest ownership in productive economic wells in the areas indicated as of December 31, 2007, based on our third party reservoir engineering report. Gross represents the total number of wells in which we own a working interest. Net represents our proportionate working interest resulting from our ownership in gross wells. Productive wells are wells that are capable of producing natural gas or oil in economic quantities. Wells that are completed in more than one producing horizon are counted as one well.

	Productive Wells					
	Natural Gas		Oil		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Hilltop area, East Texas	17	12.0			17	12.0
Powder River Basin, Wyoming and Montana	283	125.2			283	125.2
Total United States	300	137.2			300	137.2

As of December 31, 2007, we had no commercially productive wells in Australia.

Natural Gas and Oil Reserves

Our estimated total net proved reserves of natural gas and oil as of December 31, 2007 and the present values of estimated future net revenues attributable to those reserves as of those dates are presented in the following table. These estimates were prepared by NSAI and are part of their reserve reports on our natural gas and oil properties. The estimates of NSAI were based on a review of geologic, economic, ownership and engineering data that we provided.

In accordance with SEC regulations, estimates of our proved reserves and future net revenues are made using sales prices in effect as of the date of the 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 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.

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	Total Proved Reserves as of December 31, 2007			
	Producing	Non-producing	Undeveloped	Total
Natural gas (MMcf)	$ 21,778	12,280	20,764	54,822
Oil (MBbls)	9			9
Total proved reserves (MMcfe)	21,831	12,280	20,764	54,875
Standardized measure of discounted future net cash flow (000)	$ 70,374	$ 40,160	$ 21,698	$ 132,232

Pricing Assumptions

SEC regulations require that the natural gas and oil prices used in the NSA reserve reports are the period-end prices for natural gas and oil at December 31, 2007. These prices are held constant in accordance with SEC guidelines for the life of the wells included in the reserve reports but are adjusted by lease for energy content, quality, transportation, compression and gathering fees, and regional price differentials. The pricing assumptions are listed below:

	As of December 31, 2007	
	Gas ($/MMBtu)	Oil ($/Bbl)
Production:		
Hilltop Area	$ 6.795	$ 92.50
Powder River Basin	$ 6.040	$

The weighted average natural gas and oil prices after basis adjustments used in our reserve valuation as of December 31, 2007 were $6.08 per Mcf and $93.88 per barrel.

The prices used in calculating the estimated future net revenue attributable to proved reserves do not reflect market prices for natural gas and oil production sold subsequent to December 31, 2007. There can be no assurance that all of the estimated proved reserves will be produced and sold at the assumed prices. Accordingly, the foregoing prices should not be interpreted as a prediction of future prices.

For additional information concerning our estimated proved reserves, the standardized measure of discounted future net cash flows of the proved reserves at December 31, 2007, 2006 and 2005 and the changes in quantities and standardized measure of such reserves for each of the three years then ended, see Note 21 Supplemental Oil & Gas Disclosures Unaudited to our annual consolidated financial statements, which begin on page F-27.

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 natural gas from our properties with spot market contracts that vary with market forces on a monthly basis. While overall natural 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 natural gas production. Powder River Basin natural gas is sold under spot market contracts to major pipeline and natural gas marketing companies.

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Australian natural gas markets and 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 any natural gas infrastructure. The initial gas market for PEL 238 natural gas is anticipated to be an electricity generation facility owned and operated by Eastern Star Gas Ltd. and located near the town of Narrabri, New South Wales, Australia. Although there currently is no pipeline from the existing and planned CBM project areas, we and our joint venture partner are in the permitting phase for the construction of the gathering system and pipeline, which is anticipated to be completed by late 2008.

The longer term 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-Newcastle-Wollongong areas of New South Wales. Recent announcements of planned LNG facilities in southern Queensland are to be sourced from coalbed methane projects, which could potentially lead to the possibility of a portion of future PEL 238 production being sold to LNG export facilities. In March 2007, we announced that we had executed, along with our joint venture partner, a MOU with Macquarie Generation, a government-owned electricity generator in the state of New South Wales, Australia. The MOU sets the framework for negotiation of a potential long-term agreement to supply natural gas for Macquarie Generation s Bayswater power station. In November 2007, we announced that we and our joint venture partner had entered into a second MOU with Babcock & Brown (Babcock & Brown MOU) to supply gas from the PEL 238 and PEL 433 concessions for use in the generation of electricity. The Babcock & Brown MOU envisions the supply of up to 38 Bcf per year of natural gas from the Gunnedah Gas Project over multiple years for use in a gas fueled power station to be developed by Babcock & Brown in northern New South Wales, Australia commencing in late 2010. Natural gas sales under the anticipated agreements could be expanded to meet requirements for power station developments at other locations, though there is no assurance that such an agreement will ultimately be reached or that such volumes will ultimately be produced from the PEL 238 and PEL 433 concessions. In addition, a potential gas supply and purchase agreement with Macquarie Generation would serve to underpin the development of the approximately 300 kilometers of pipeline infrastructure necessary to transport gas from the PEL 238 concession to Bayswater. An additional 150 kilometers of pipeline infrastructure would be required to access the natural gas markets of Sydney-Newcastle-Wollongong area.

The area on which PEL 433 is located is subject to a native title claim lodged in June 2002 by the Tubba-Gah People (NSD6010/02). See Governmental Regulation Australian Governmental Regulation-Native Title .

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 our efforts result in commercial CBM production from this license, minimal infrastructure expenditures would be necessary to connect to existing pipelines. Victoria has both a spot market for natural gas and a developed market for contract sales of natural gas.

Our very limited oil production in Texas and the Appalachian Basin 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.

In March 2008, we entered into formal agreements with ETC Texas Pipeline, Ltd. (ETC) for the gathering, treating, purchase and transportation of our natural gas production from the Hilltop area of East Texas. These agreements are effective September 1, 2007 and have a term of 10 years. ETC currently provides us 50 MMcfd of treating capacity and 120 MMcfd of gathering capacity. We have the right to request ETC build, at their cost, up to 150 MMcfd of treating and gathering capacity during the term of the agreement, provided that our production equals 85% of the then existing treating and gathering capacity for a 30 day period. We may at any time elect to have our treating and gathering capacity increased subject to cost indemnifications to ETC. Additional treating and gathering capacity requests must be in at least 25 MMcfd and 5 MMcfd increments, respectively. In addition, we must furnish to ETC information that reasonably demonstrates that our projected production for the five years after expansion is sufficient to warrant the costs to create the expanded treating and gathering capacity. The incremental volume increases in treating and gathering capacity shall be subject to marginal increases in treating fees. Pursuant to the agreements, we have access up to 150 MMcfd of firm transportation on ETC s system or the pipelines of its affiliates or subsidiaries from the tailgate of the treating facility to Katy Hub. We have the option to sell and ETC has the obligation to buy, up to 150 MMcfd of our Hilltop production at delivery points upstream of ETC s gathering and treating facilities. We do not have an obligation to deliver to ETC volumes in excess of 150 MMcfd, but should ETC elect to purchase such excess volumes, purchases will be subject to the treating and gathering expansion terms set forth in the agreements.

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During 2007, ETC and Enserco Energy, Inc. (Enserco) accounted for 78% and 20% of our natural gas and oil revenues, respectively. During 2006, sales to ETC and Enserco accounted for 63% and 25% of our natural gas and oil revenues, respectively. During 2005, ETC and Enserco accounted for 65% and 26%, respectively, of our natural gas and oil revenues. Although ETC is the major natural gas purchaser and transporter in the area of our deep Bossier play and only limited natural gas purchaser and transporter alternatives are currently available in this area, management believes that other natural gas purchasers and transporters could ultimately be located and would minimize any long-term material adverse impact on our financial condition or results of operations. Management believes that the loss of Enserco in the Powder River Basin would not have a long-term material adverse impact on our financial position or results of operations, as there are numerous other purchasers operating in the Powder River Basin.

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, many of whom have greater financial resources and in many instances, have been engaged in the exploration and production business for a much longer time than we have. Many of our competitors also have substantially larger operating staffs than we do. Many of these competitors not only explore for and produce natural gas and oil but also market natural gas and oil and other products on a regional, national or worldwide basis. These competitors may be able to pay more for productive natural gas and oil properties and exploratory prospects and define, evaluate, bid for and purchase a greater number of properties and prospects than us. In addition, these competitors may have a greater ability to continue exploration activities during periods of low market prices. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment.

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 smaller and have a more limited operating history than most of our competitors 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 providing the manpower to operate them and provide related services.

Governmental Regulation

In addition to the environmental regulations discussed below, our natural gas and oil exploration, production and related operations are subject to extensive rules and regulations promulgated in the United States and Australia. 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; ongoing obligations for licensing; 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 prospect or acreage.

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.

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

Additional proposals and proceedings that might affect the natural gas industry are considered from time to time by Congress, 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 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 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 natural gas and oil industry. Many departments and agencies, both federal and state are authorized by statute to issue, and have issued, rules and regulations binding on the natural gas and oil industry and its individual participants. The failure to comply with such rules and regulations can result in substantial penalties. The regulatory burden on the natural gas and oil 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 natural gas and oil 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. The states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of the natural gas and oil properties; the establishment of maximum rates of production from natural gas and oil wells; the spacing of wells; and the plugging and abandonment of wells and removal of related production equipment. These regulations can limit the amount of the natural gas and oil 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 Governmental Regulation

Commonwealth and State Laws and Regulations. The regulation of the activities of participants in 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, petroleum industry licensing, foreign investment, cultural heritage and native title restrictions on accessing resources in Australia. These regulations are in addition to any state level regulations.

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Foreign Investment Regulation. 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 Treasurer 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, investment in or formation of a new business, or acquisition of urban land will require review and approval under the commonwealth foreign investment policy and regulations.

Native Title. In a landmark Australian High Court decision in 1992, it was recognized that the native title to land of Indigenous Australians survived the acquisition of sovereignty by the British Crown. However native title to any particular area will only survive to the present if it has not been extinguished subsequently. Native title may be extinguished by the action of government, such as the creation of an interest that is inconsistent with native title. In particular, the grant of the right to exclusive possession through freehold title or a lease will wholly extinguish native title. Native title may also be extinguished if the connection between the land and the group of Aboriginal people claiming native title has been lost. The *Native Title Act 1993 (Cth)* 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 how dealings affecting native title can be conducted in the future. Native title claims by Aboriginal groups can cover existing and potential natural gas and oil exploration and development areas. If we apply to the relevant state or territory for an onshore exploration permit or production license over Crown land or Aboriginal land which has a registered native title claimant or a registered native title holder, we will have to go through a mandatory negotiation process, followed by an arbitration conducted by the National Native Title Tribunal if no agreement can be reached through negotiation. The results of the negotiation may impose significant financial obligations on us. Each application for an exploration permit, production license or a pipeline license must be examined individually in order to determine the existence of native title claims or determinations. To validly affect native title, permits and licenses must be granted in compliance with the *Native Title Act 1993 (Cth).*

Australian Petroleum Regulation and Gas Markets. All petroleum tenements in which we hold an interest are subject to specific licensing regulation in the relevant states. Each exploration permit or production license will (depending on the nature of the license and the state in which the project is located) be issued subject to various obligations. These may include obligations as to expenditure, payment of rent, consultation with occupiers and rehabilitation. These obligations must be met to maintain the good standing of the tenement. Licenses may be cancelled or revoked for non compliance. In Australia, the ownership of minerals (including petroleum) is vested in the government and ownership only passes to the license holder once the relevant mineral is extracted. We are required to pay Government royalties of 10% of the wellhead value of petroleum extracted. 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 on our operations but believe it could benefit us.

Environmental Regulation

Our U.S. natural gas and oil exploration and production operations and similar operations that we do not operate but in which we own a working interest 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

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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 may result in the issuance of injunctions limiting or prohibiting operations, as well as administrative, civil and even criminal penalties. The effects of these laws and regulations, as well as the assessment of 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 and regulations or the modification or more stringent enforcement of existing laws and 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 significant resources in order to satisfy existing applicable environmental laws and regulations. However, there is no assurance that costs to comply with existing, and any new environmental laws and regulations in the future will not be 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.

U.S. Environmental Regulations

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 transported, 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

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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. In the past, proposals have been made to amend RCRA to rescind this exemption. Repeal or modification of the exception or similar exemptions in state law could increase the amount of hazardous waste we are required to manage and dispose of and could cause us to incur increased operating cost, which could have a significant impact on us as well as the natural gas and oil 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 or recycling. In addition, many of these properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons was not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes (including substances disposed of or released by prior owners or operators), remediate contaminated property or perform remedial plugging or pit closure operations to prevent future contamination.

Water Discharges. Our operations and other operations in which we own a working interest are subject to the Clean Water Act, or CWA, as well as the Oil Pollution Act, or OPA, and analogous state laws and regulations. These laws and regulations impose detailed requirements and strict controls regarding the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States, including wetlands. Under the CWA and OPA, any unpermitted release of pollutants from operations could cause us to become subject to the costs of remediating a release; administrative, civil or criminal fines or penalties; or OPA specified damages, such as damages for loss of use and natural resource damages. In addition, in the event that spills or releases of produced water from natural gas and oil production operations were to occur, we would be subject to spill notification and response requirements under the CWA or the equivalent state regulatory program. Depending on the nature and location of these operations, spill response plans may also have to be prepared.

Our natural gas and oil exploration and production operations and other operations in which we own an interest generate produced water as a waste material, which is subject to the disposal requirements of the CWA, Safe Drinking Water Act, or SDWA, or an equivalent state regulatory program. Naturally occurring groundwater is also typically produced by CBM production in our operations or in other operations in which we own an interest. This produced water is disposed of by re-injection into the subsurface through disposal wells, discharge to the surface, or in evaporation ponds. Whichever disposal method is used, produced water must be disposed of in compliance with permits issued by regulatory agencies and in compliance with applicable environmental regulations. This water can sometimes be disposed of by discharging it under discharge permits issued pursuant to the CWA or an equivalent state program. Another common method of produced water disposal is subsurface injection in disposal wells. Such disposal wells are permitted under the SDWA or an equivalent state regulatory program. To date, we believe that all necessary surface discharge or disposal well permits have been obtained and that the produced water has been discharged into the produced water disposal wells in substantial compliance with such obtained permits and applicable laws. Nonetheless, in connection with CBM production in the Powder River Basin, a concern common to many operators in the Basin is the potential for opposition by individuals or groups to the issuance of a permit for the discharge or disposal of water generated by production activities. Such opposition could result in delays, limitations or denials with respect to environmental or other approvals necessary to develop our acreage in the Powder River Basin, which could adversely affect our financial condition or results of operations.

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 CAA or equivalent state and local regulatory programs, although many small air emission sources are expressly exempt from such regulations. To the extent that these air emissions are regulated, they are generally regulated by permits issued by state regulatory agencies. To date, we believe that no unusual difficulties have been encountered in obtaining air permits. However, there is no assurance in the future, we will not be required to incur capital expenditures in connection with maintaining or obtaining operating permits and approvals addressing air emission-related issues.

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

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

In response to recent studies suggesting that emissions of certain gases including carbon dioxide, may be contributing to warming of the Earth s atmosphere, many foreign nations have agreed to limit emissions of these gases, generally referred to as greenhouse gases , pursuant to the United Nations Framework Convention on Climate Change, also known as the Kyoto Protocol . Although the United States is not participating in the Kyoto Protocol, the current session of Congress is considering climate change legislation, with multiple bills having already been introduced in the Senate that propose to restrict greenhouse gas emissions. One bill recently approved by the U.S. Senate Environment and Public Works Committee, known as the Lieberman-Warner Climate Security Act or S.2191, would require a 70% reduction in emissions of greenhouse gases from sources within the United States between 2012 and 2050. The Lieberman-Warner bill proposes a cap and trade scheme of regulation of greenhouse gas emissions or a ban on emissions above a defined reducing annual cap. Covered parties will be authorized to emit greenhouse emissions through the acquisition and subsequent surrender of emission allowances that may be traded or acquired on the open market. A vote on this bill by the full Senate is expected to occur before mid-year 2008. In addition, at least 17 states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs require either major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries or gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year until the overall greenhouse gas emission reduction goal is achieved. Depending on the particular program, we could be required to purchase and surrender allowances, either for greenhouse gas emissions resulting from our operations or from combustion of fuels (such as natural gas or oil) we produce. Although we would not be impacted to a greater degree than other similarly situated producers of natural gas and oil, a stringent greenhouse gas control program could have an adverse effect on our cost of doing business and could reduce demand for the natural gas and oil we produce.

Also, as a result of the U.S. Supreme Court s decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA may be required to regulate carbon dioxide and other greenhouse gas emissions from mobile sources, such as cars and trucks even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The EPA has indicated that it will issue a rulemaking notice to address carbon dioxide and other greenhouse gas emissions from vehicles and automobile fuels, although the date for issuance of this notice has not been finalized. The Supreme Court s holding in *Massachusetts* that greenhouse gases including carbon dioxide fall under the federal Clean Air Act s definition of air pollutant may also result in future regulation of carbon dioxide and other greenhouse gas emissions from stationary sources under certain Clean Air Act programs. New federal or state restrictions on emissions of carbon dioxide that may be imposed in areas of the United States in which we conduct business could also adversely affect our cost of doing business and demand for the natural gas and oil we produce.

Finally, legislation continues to be introduced in Congress and development of regulations continues in the Department of Homeland Security, or DHS, and other agencies concerning the security of industrial facilities,

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including natural gas and oil facilities. Our operations and the operations of the natural gas and oil industry in general may be subject to such laws and regulations. The federal Department of Homeland Security Appropriations Act of 2007 required the DHS to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including natural gas and oil facilities that are deemed to present high levels of security risk . The DHS issued an interim final rule, known as the Chemical Facility Anti-Terrorism Standards Interim Final Rule, in April 2007 regarding risk-based performance standards to be attained pursuant to the Act and, on November 20, 2007, further issued an Appendix A to the interim rule that establish chemicals of interest and their respective threshold quantities that trigger compliance with this rule. Facilities that possess the threshold quantities of chemicals of interest must submit to an initial screening process for DHS to determine if they present a high level of security risk. Facilities that are deemed to pose a high level of security risk will be required to prepare and submit Security Vulnerability Assessments and Site Security Plans and comply with other regulatory requirements including those regarding inspections, audits, recordkeeping and protection of Chemical-terrorism Vulnerability Information. We have not yet determined the extent to which our facilities are subject to the interim rules or the associated costs to comply, but it is possible that such costs could be substantial.

Australian Environmental Regulations

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

Australia ratified the Kyoto Protocol on December 3, 2007, and officially committed to meeting its Kyoto Protocol target. Australia set a target to reduce greenhouse gas emissions by 60% on 2000 levels by 2050 and committed to actively participate in negotiations working towards a post 2012 agreement involving developed and developing countries. Australia has introduced a *National Greenhouse and Energy Reporting Act 2007*, which establishes a single national system for reporting greenhouse gas emissions, abatement actions and energy consumption and production by corporations from July 1, 2008. Data reported through the system will underpin the Australian Emissions Trading Scheme, or AETS, which is to be introduced by 2010. The consultation stage and detailed design of the AETS is to be finalized by the end of 2008. The government has made it clear that it plans to introduce a cap and trade scheme in which total emissions are capped, permits allocated up to the cap and trading allowed to let the market find the cheapest way to meet any necessary emission reductions. As the details of the AETS are not yet finalized, we are unable at this stage to assess the likely impact of the AETS on our operations in Australia.

The legislation regulating environmental assessment at a commonwealth level is the *Environmental Protection and Biodiversity Conservation Act 1999 (Cth.)*. This Commonwealth Act establishes a regime for protecting the environment, flora and fauna biodiversity and Australian national heritage. It requires any person taking an action which could have a significant impact on one of these values to refer it to the commonwealth Minister for the Environment for consideration and potential assessment. The Act only applies to matters of national environmental or heritage significance. These are matters which impact on a world heritage site, Ramsar wetlands, species which are listed as threatened under the Act, migratory species, nuclear actions and commonwealth marine areas or places listed on the commonwealth heritage list. Operators are required to assess their projects to determine whether an action is likely to have a significant impact on matters of national environmental significance and make a decision respecting submission of that assessment to a public referral process. The referral is expected to add time to the existing approval process but its effect on a project will depend on the significance of the impact identified. In addition, see the discussion in Business-Gunnedah Basin, New South Wales, Australia for a discussion of the New South Wales government s bioregion study involving PEL 238.

Environmental protection and planning issues are also regulated in each state and territory by specific legislation enacted by each state or territory. The governments of New South Wales and Victoria both have a suite of legislation regulating environmental matters in their states. Generally speaking, onshore natural gas and oil projects in New South Wales and Victoria require an environmental approval from the state (and sometimes commonwealth) government, land use planning approval from local government and an approval under the relevant petroleum regime (as referred to above). Legislation provides for the integrated assessment of these issues. The environmental regulators in both New South Wales and Victoria have the ability to require a project operator to prepare and implement a plan to improve the environmental performance of a project and may also amend the conditions on an existing environmental approval. As such, the environmental regulation of a project may not be assumed to remain static following approval and may become more onerous over time. The legislation imposes a licensing approval and contamination management scheme which may impact on our operations and impose a liability which may extend beyond the time period during which properties are operated, occupied or owned. The laws and regulations also restrict emissions to air, land and water and may control or regulate substances which can be released into the environment and the manner in which they are transported and disposed of. Approvals will usually include terms which require remediation and reinstatement obligations for the site during the course of operations and following closure of the project.

Australian laws and regulations protecting archeological relics, cultural, natural and built heritage as well as native flora and fauna can also impact on our operations and impose obligations in respect of restitution or replacement, as well as liability in respect of damage. In particular, indigenous cultural heritage protection laws are becoming increasingly stringent and in many states and the Northern Territory the specialist indigenous heritage protection laws require a proponent to negotiate directly with indigenous groups with respect to a major project.

Industry Segment and Geographic Information

We operate in one industry segment, which is the exploration, development and production of natural gas and oil. Our operational activities are conducted in the United States and Australia with only the United States currently having revenue generating operating results.

Employees

As of May 1, 2008, we had 24 employees, all of whom are full time. We use the services of independent consultants and contractors to perform various professional services, including reservoir engineering, land, legal, regulatory reporting, environmental and tax services. On those properties where we are not the operator, we rely on outside operators to drill, produce and market our natural gas and oil. Our employees do not belong to a union or have a collective bargaining organization. Management considers its relationship with employees to be good.

Corporate Offices

Our parent leases corporate offices at 1331 Lamar Street, Suite 1080, Houston, Texas 77010. Our office space covers 9,332 square feet at a monthly rental of $17,100 through October 2010. We maintained an office in Miami, Florida (our Chief Executive Officer s city of residence) through April 2007 at a monthly rental of $2,700 per month.

Internet Website Access

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange are made available free of charge on our internet website at www.gastar.com as soon as reasonably practicable after we have electronically filed the material with, or furnished it to, the SEC. The public may read and copy any materials we have filed with the SEC at the SEC s Public Reference Room at 100 F Street, NE, Room 1580, Washington, DC 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. The SEC maintains an internet website that contains our reports, proxy and information statements and our other SEC filings. The address of that site is www.sec.gov. Information is also available at www.sedar.com for our filings required by Canadian securities regulators and the Toronto Stock Exchange. None of the information on our internet website or filed by us on www.sedar.com should be considered incorporated into, or considered a part of, this report.

We also make available free of charge on our internet website at www.gastar.com our:

- Code of Ethics;
- Terms of Reference of our Audit Committee;
- Terms of Reference of our Reserves Review Committee;

Terms of Reference of our Governance Committee;

Terms of Reference of our Remuneration Committee;

Terms of Reference of our Nominating Committee; and

Whistleblower Procedure.

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LEGAL PROCEEDINGS

The Company is a party to various litigation matters arising out of the normal course of business. The ultimate outcome of the matters discussed below cannot presently be determined, nor can the liability that could potentially result from an adverse outcome be reasonably estimated at this time. The more significant litigation matters are summarized below.

Navasota Resources L.P. (Navasota) vs. First Source Texas, Inc. (now Gastar Exploration Texas, Inc.), First Source Gas L.P. (now Gastar Exploration Texas LP) and Gastar Exploration Ltd. (Cause No. 0-05-451) District Court of Leon County, Texas 12th Judicial District. This lawsuit, dated October 31, 2005, contends that the Company breached Navasota s preferential right to purchase 33.33% of the Company s interest in certain natural gas and oil leases located in Leon and Robertson Counties and sold to Chesapeake Energy Corporation pursuant to a transaction closed November 4, 2005. The preferential right claimed is under an operating agreement dated July 7, 2000. The Company contends, among other things, that Navasota neither properly nor timely exercised any preferential right election it may have had with respect to the inter-dependent Chesapeake transaction. In July 2006, the District Court of Leon County, Texas issued a summary judgment in favor of the Company and Chesapeake. Navasota filed a Notice of Appeal to the Tenth Court of Appeals in Waco. Oral argument was heard on September 26, 2007 and the Court of Appeals issued its opinion on January 9, 2008 reversing the trial court s rulings and rendering judgment in favor of Navasota on all counts. The Company and Chesapeake filed a motion for rehearing on February 6, 2008, and if unsuccessful, will consider filing a petition for review to the Texas Supreme Court. Pursuant to an agreement between the Company and Chesapeake, any adverse result in this matter should impact only Chesapeake s assigned leasehold interests. While this matter is pending, it is possible that expenditures incurred, or authorizations for proposed expenditures, for drilling activities on leases which include the disputed interest may remain unpaid or not be authorized by the non-operators asserting competing ownership rights, which could require the Company to either fund a disproportionate amount of drilling costs at its own risk or postpone its drilling program on affected leases.

Gastar Exploration Texas LP v. John E. McFarlane, et al (Cause No. 0-06-161) 87th Judicial District Court of Leon County, Texas. This suit is to quiet title to an undivided 25% mineral interest under an oil and gas lease dated December 4, 2003, covering approximately 2,598 gross acres (the Lease). John E. McFarlane and certain other family members contend that an undivided 25% mineral interest in the lands covered by the Lease are owned in trust by the grandchildren of Fay W. McFarlane and are not covered by the Lease as Gastar claims. McFarlane, et. al., has filed an answer to the Company s petition and also filed several different motions for summary judgment, which were denied by the District Court. A day long mediation of this lawsuit occurred on August 24, 2007, but the parties were unable to settle this matter at that time. The lawsuit is currently in the discovery phase and is currently set for a non-jury trial in October 2008. The existence of unleased mineral interests in this Lease could adversely impact the future development of the Lease. The Company will continue to vigorously pursue this claim.

Spencer D. Plummer, III v. GeoStar Corporation, Classic Star LLC, Gastar Exploration, Ltd., Thom Robinson, Tony Ferguson, and John W. Parrott; In the United States District Court of Utah, Central Division (Case No. 2:07-CV-00409). This lawsuit was filed on May 24, 2007 initially in Utah state court by Spencer Plummer, or the Plaintiff, in which he asserts breaches of his Employment Agreement and subsequent Termination Agreement (the Agreements) with his employer, Classic Star, a subsidiary of GeoStar. The Plaintiff claims that he has not received benefits promised under such Agreements, including 699,249 shares of Company stock. The Company is not a party to the Agreements on which Plaintiff s claims are expressly based; however, the Company and Plaintiff are parties to a Stock Option Agreement on which Plaintiff claim to Company stock is partially based. The Company filed an Answer and Motion to Dismiss for lack of personal jurisdiction in Utah and for Plaintiff s failure to state a claim upon which relief can be granted. Plaintiff filed a Motion to Remand to state court, and on September 5, 2007, the Court denied Plaintiff s Motion to Remand. Thereafter, the Company s co-defendant, Classic Star LLC, moved to transfer and consolidate the case in a United States Judicial Panel on Multi District Litigation (MDL Panel) in Kentucky with other cases in which Classic Star LLC is a named defendant. On October 22, 2007, the MDL Panel granted the motion to transfer. The Company is awaiting the Kentucky court s ruling on its Motion to Dismiss.

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Arbitration and Litigation with GeoStar Corporation and Affiliates

Arbitration against GeoStar Corporation and Affiliates. On October 18, 2006, in connection with 10 wells to be drilled in Victoria, Australia on the jointly owned EL 4416 exploration license operated by GeoStar Corporation, the Company sent a letter to GeoStar demanding the arbitration of certain disputed issues and interpretations under a Participation and Operating Agreement (POA) with GeoStar and its subsidiaries. Among other items, the claims the Company presented for resolution in arbitration include claims relating to GeoStar s demands for cash calls under the POA while simultaneously asserting that certain provisions of the POA, including overhead reimbursement rates, need to be renegotiated on terms that the Company believes are not reasonable or within industry standards. The Company has also requested that GeoStar s Australian subsidiary provide a record title assignment of the Company s beneficial interests in EL 4416, the exploration license in the Gippsland Basin property in Victoria, Australia. The Company has approximately $9.9 million invested in EL 4416 as of December 31, 2007. GeoStar contends that the Company is not entitled to the record title assignment notwithstanding the Company s significant investment. The Company s former Chairman of the Board is a major shareholder and President of GeoStar. GeoStar has voluntarily dismissed its efforts to enjoin the arbitration from proceeding and has answered and asserted counterclaims. Those counterclaims include (a) a request for a declaration that the Company has no rights to participate in brown coal projects in EL 4416, (b) a request for a declaration that the Company did not earn an interest under the POA as to certain wells the Company drilled in East Texas, (c) breach of contract for failure to pay certain bills and expenses and (d) breach of contract to pay for employee expenses and services. The Company, which denies and intends to vigorously defend each of these counterclaims, contends that it has participation rights to the full scope of EL 4416 under the terms of the POA and that the Texas wells were drilled on lands to which the Company obtained rights under separate 2005 Purchase and Sale Agreements. The three-member arbitration panel has been appointed. The date of the arbitration has been postponed and a new date has not been determined.

Gastar Exploration, Ltd., Gastar Exploration Texas, Inc., f/k/a First Texas Development, Inc., Gastar Exploration Texas LLC, f/k/a Bossier Basin, LLC, and Gastar Exploration Texas LP, f/k/a First Source Gas, LP v. GeoStar Corporation, First Source Texas, Inc., First Source Bossier, LLC, and First Texas Gas, LP. In July 2007, the Company filed a lawsuit in Robertson County, Texas against GeoStar and affiliates seeking relief in connection with the failure by GeoStar and its affiliates to execute formal assignments of certain leases that were omitted from the schedule of leases attached to the assignments executed by GeoStar affiliates in June 2005 pursuant to Purchase and Sale Agreements covering Texas properties of GeoStar and its affiliates. The lawsuit asks the court to decree that in the transaction evidenced by the Purchase and Sale Agreements, affiliates of the Company acquired title to all properties in Texas in which GeoStar and its affiliates owned an interest and that GeoStar and its affiliates are obligated to execute formal assignments with regard to all such leases. GeoStar and one of its affiliates have filed a challenge to the Texas court s jurisdiction. Additionally, GeoStar and certain of its affiliates have also filed counterclaims in this litigation, which are described below and in the section below entitled GeoStar Look Back Developments .

Gastar Exploration Ltd., Gastar Exploration USA, Inc. f/k/a First Sourcenergy Wyoming Inc., Gastar Exploration New South Wales, Inc., f/k/a First Sourcenergy Group, Inc., Gastar Exploration Victoria, Inc. f/k/a First Sourcenergy Victoria, Inc.,, Gastar Exploration Texas, Inc., f/k/a First Texas Development, Inc., Gastar Exploration Texas LLC, f/k/a Bossier Basin, LLC, and Gastar Exploration Texas LP, f/k/a First Source Gas, LP v. GeoStar Corporation. In July 2007, the Company and affiliates filed a lawsuit in the District Court of Harris County, Texas against GeoStar in connection with GeoStar s failure to deliver to the Company and its affiliates the corporate records of the Company and to its affiliates that have been retained by GeoStar. Representatives of the Company and its affiliates previously demanded return of the corporate records retained by GeoStar, but GeoStar failed to return the records. The lawsuit asks the court to decree that the Company and its affiliates are entitled to possession of the corporate records and order their return to the Company and its affiliates. The lawsuit also seeks recovery of actual and punitive damages, costs, and attorney s fees. GeoStar has now delivered some of the requested records that are the subject of this litigation to the Company, and the Company has requested that GeoStar deliver additional records.

Gastar Exploration, Ltd., Gastar Exploration Texas, Inc., f/k/a First Texas Development, Inc., Gastar Exploration Texas LLC, f/k/a Bossier Basin, LLC, and Gastar Exploration Texas LP, f/k/a First Source Gas, LP v. GeoStar Corporation, First Source Texas, Inc., First Source Bossier, LLC, and First Texas Gas, LP. In

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August 2007, the Company and certain affiliates filed a second lawsuit in Robertson County, Texas, seeking a declaratory judgment that the Company and its affiliates have complied with the Look-Back provisions of the Texas Purchase and Sale Agreements that are the subject of the other Robertson County, Texas lawsuit referenced above, that the Company and its affiliates have complied with the provisions of the Texas Purchase and Sale Agreements relating to the drilling of wells, and that GeoStar and its affiliates hold no farm-in interest in properties owned by the Company s affiliates. GeoStar and one of its affiliates have filed a challenge to the Texas court s jurisdiction. The defendants also have generally denied the allegations made in the lawsuit. Additionally, GeoStar and certain of its affiliates have also filed counterclaims in this litigation, which are described in the following paragraph and in the section below entitled GeoStar Look Back Developments .

Although it previously contested jurisdiction in Texas, GeoStar (together with certain of its affiliates) has as of January and February 2008 asserted counterclaims in all three Texas lawsuits similar to claims GeoStar had previously asserted and dismissed in the Michigan lawsuit described below. The counterclaims relate to Texas properties that were the subject of Purchase and Sale Agreements entered into in 2005, under which the Company acquired the interests of GeoStar-affiliated entities in properties in Texas. Specifically, GeoStar claims that the Company breached the Purchase and Sale Agreements by failing to provide information in connection with contingent Look Back payments under provisions of the Purchase and Sale Agreements, and by failing to make payments allegedly due to GeoStar under the Look-Back provisions, arising out of alleged changes in reserves following the sale of the Texas properties in June 2005. Although requesting only damages in an unspecified amount, GeoStar contends in the counterclaim that it would have been entitled under the Purchase and Sale Agreements to approximately 1.7 billion shares of Gastar stock. GeoStar also claims that the Company failed to timely comply with provisions of the Purchase and Sale Agreements relating to the drilling of 20 wells on the properties conveyed under the Purchase and Sale Agreements and by failing to drill and test at least two wells in the Travis Peak formation in Texas, allegedly entitling GeoStar to unspecified damages related to a farm-in interest under which it was allegedly entitled to the right to drill, complete, and operate wells in the Travis Peak formation on certain acreage. The Company intends to vigorously defend the counterclaims. The Company has moved to abate the Harris County proceedings with respect the counterclaims in favor of the earlier-filed Robertson County proceedings. Certain information that may be relevant to this matter is set forth below in the section below entitled GeoStar Look Back Developments .

GeoStar Corporation and West Virginia Gas Corporation v. Gastar Exploration Ltd. and J. Russell Porter. On July 27, 2007, the Company was served with a lawsuit filed by GeoStar and one of its affiliates, West Virginia Gas Corporation, in federal court in Saginaw, Michigan. GeoStar asserted a broad range of claims against the Company and its current chief executive officer, J. Russell Porter.

GeoStar initially sought in the Michigan suit to enjoin the Company s arbitration against GeoStar and its affiliates. GeoStar has now voluntarily dismissed that request with prejudice.

GeoStar also claims in the Michigan suit that the POA was cancelled effective January 1, 2005, and that the parties have operated under oral contracts since that date. GeoStar asserts that the Company has breached the alleged oral contracts by allegedly failing to pay joint interest billings, authorizations for expenditures, and cash calls relating to operations or proposed operations on EL 4416 in Australia and West Virginia properties, in an unspecified amount exceeding $75,000. GeoStar also claims that the Company has breached alleged agreements to reimburse GeoStar for various payments and services allegedly performed by GeoStar and its personnel and paid on behalf of the Company by GeoStar. GeoStar claims that the amounts of the payments and the value of the services exceed $10.0 million. GeoStar alternatively alleges that if there was no contract covering those payments and services, it allegedly is entitled to reimbursement on equitable principles. On January 15, 2008, the federal court granted the Company s motion to dismiss these claims for failure to state a claim on which relief could be granted. GeoStar filed a motion asking that the Court reconsider that ruling or permit it to replead the claims. On February 8, 2008, the federal court denied the motion to reconsider but granted GeoStar permission to replead those claims, which it did on February 22, 2008. In repleading those claims, GeoStar has restated the prior claims for oral agreement to reimburse certain expenses or equitable entitlement to reimbursement of certain expenses, and it specifies a number of items for which GeoStar is allegedly entitled to reimbursement from the Company. Pursuant to these claims, which are substantially duplicated by certain of the counterclaims GeoStar pursues in the arbitration, GeoStar seeks approximately $17.0 million. The Company filed a response to these claims on March 7, 2008.

GeoStar also asserted claims in the Michigan lawsuit relating to Texas properties that were the subject of Purchase and Sale Agreements entered into in 2005. GeoStar has voluntarily dismissed those claims without prejudice from the Michigan lawsuit and re-asserted similar claims in pending litigation in Harris and Robertson Counties, Texas as discussed above and below under GeoStar Look Back Developments .

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West Virginia Gas Corporation (WVGC), an affiliate of GeoStar, also asserts claims against the Company s current chief executive officer, alleging that the Company and its current chief executive officer tortiously interfered with an alleged contract between WVGC and certain West Virginia individuals and entities. According to the lawsuit, these individuals and entities allegedly promised to give their oil, gas, and coalbed methane opportunities in West Virginia and Pennsylvania to WVGC. WVGC alleged that Gastar and its chief executive officer caused those individuals and entities to establish and use new business entities to allegedly conceal opportunities from West Virginia Gas Corporation and to funnel them to the Company, the Company s chief executive officer and the West Virginia individuals and entities. On January 15, 2008, the federal court dismissed these claims to the extent they were brought by GeoStar and to the extent they were brought against the Company. The court denied our chief executive s motions to dismiss WVGC s claim and a motion to reconsider that denial. Our chief executive intends to vigorously defend the claim.

GeoStar Look Back Developments. The Purchase and Sale Agreements between GeoStar and the Company relating to certain East Texas properties acquired by the Company in 2005 (the PSAs) contain a Look Back provision that is the subject of claims in three of the previously described lawsuits with GeoStar. Under the 2005 PSAs, GeoStar conveyed interests in certain Texas properties to the Company and was paid an agreed $43.5 million in consideration for the properties (including cash, 8.6 million shares of Company common stock and promissory notes), subject to certain purchase price adjustments relating to the period prior to closing. The interests conveyed by the PSAs comprise a portion of the security for the notes and the Guarantees.

Under the Look Back provision, two Look Back payments are to be calculated based in part on changes in proved and probable reserves attributable to certain of the Company s leasehold interests over certain periods of time ending June 30, 2006 and 2007. If a Look Back payment is due to GeoStar under the PSAs, the PSAs require the payment to be effected through the issuance of the Company s stock.

The PSAs provide that the calculation of the Look Back payment shall be based upon reserve estimates reported by Netherland Sewell & Associates, Inc. (NSA), or in certain circumstances, based upon an average of the NSA estimates and estimates obtained by GeoStar from an independent, professionally certified reservoir engineering firm utilizing the same regulatory requirements and reserve calculation guidelines as those employed by NSA in its estimates. Based on the NSA reserves estimate and the Look Back calculations set forth in the PSAs, the Company believes that no additional issuance of Company common shares is due GeoStar under the Look Back provision.

On November 1, 2007, GeoStar informed the board of directors of our Parent that it intended to submit a reserve report for purposes of the June 30, 2006 and 2007 Look Back analyses showing that the gross reserves attributable to the Company s leasehold interests are substantially greater than those reflected in the NSA reserve reports on which the Company s Look Back analyses were based. On November 7, 2007, GeoStar submitted a reserve report to the Company that reported a substantially greater reserve estimate than the estimates in the NSA reserve report.

On November 14, 2007, the Company received a reserve report of T.J. Smith & Company, Inc. (T.J. Smith) as well as a demand letter from GeoStar s counsel (the Demand Letter) in which GeoStar asserted a purported right under the PSAs to receive additional shares of Gastar stock as a Look Back payment. In the Demand Letter, GeoStar asserts that T.J. Smith has estimated that the total proved and probable reserves in the Company s Texas properties attributable to 100% of the working interest amount to 2.15 trillion cubic feet of gas, a number which is approximately fourteen times more than the proved and probable reserves estimated by NSA, the engineering firm selected by the parties in the PSAs. On the basis of that reserves estimate, GeoStar asserts in the Demand Letter that it is entitled to a Look Back payment of approximately 1.7 billion shares of Gastar common stock, which if issued would constitute approximately 89% of the Company s common equity and would result in a change in control of the Company under the Company s debt agreements. In the Demand Letter, GeoStar further asserts that if its demand is not met, it will pursue remedies that may include reclaiming operatorship over certain of the Company s Texas properties, rescission of the PSAs resulting in return of the properties covered by the PSAs and consideration paid, and unspecified injunctive relief. The Company does not believe that GeoStar is entitled to these remedies.

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The Company believes that GeoStar s assertions are without merit. The Company believes that the T.J. Smith reserve report was submitted in bad faith and does not meet the requirements of the PSAs because, among other things, it does not follow the same regulatory requirements and reserve calculation guidelines as those employed by NSA, as required by the terms of the PSAs. In addition, GeoStar has asserted that the Look Back analysis should be based on changes in reserves attributable to the entirety, or 8/8ths, of the Company s leasehold interests with respect to its Texas properties, rather than on changes in reserves attributable to GeoStar s net revenue interest in those properties as of the effectiveness of the PSAs, as the Company believes. The Company is pursuing discovery of data pertinent to the T.J. Smith report and GeoStar s contentions relating thereto and will continue to evaluate the Company s legal positions and options based on such discovery.

The Company intends to vigorously defend itself against GeoStar s assertions. However, an unfavorable outcome in litigation relating to the Look Back could have a material adverse effect on the Company were GeoStar to obtain issuance of the requested shares and obtain control of the Company, rescission of the PSAs, or other relief to which it asserted it was entitled in the November demand letter. A change in control of the Company as a result of an issuance of shares to GeoStar may require the Company to refinance substantially all of its indebtedness under its existing debt agreements, which refinancing may not be obtainable or may not be on terms as favorable as under current debt agreements. Although the Company does not currently anticipate the need to access the equity capital markets through 2008 or early 2009 to continue its business plan, until these issues are resolved in whole or in significant part, it will be difficult for the Company to raise capital through the sale of equity.

In 2007, the Company recorded a $1.4 million litigation settlement expense accrual related to a proposed settlement with GeoStar regarding the various GeoStar arbitration and litigation matters. The settlement proposal was never finalized. At March 31, 2008, the Company had a receivable from GeoStar of approximately $3.7 million that was fully reserved due to the various litigation matters.

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SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth certain information about the beneficial ownership of our Parent s common shares by:

- Each of our Parent s directors;
- Named executive officers listed in the Summary Compensation Table set forth under the caption Compensation of Executive Officers and Directors below;
- All of our Parent s named executive officers and directors as a group; and
- Each person known to the Company to be the beneficial owner of more than 5% of our Parent s outstanding common shares.

Unless otherwise indicated and subject to community property laws where applicable, management believes that all persons named in the following table have sole voting and investment power over all common shares reported as beneficially owned by them.

The following table is based upon information supplied by officers, directors, certain named individuals, principal shareholders and from documents filed with the SEC. Applicable percentages are based on 208,204,570 common shares outstanding on May 1, 2008, subject to adjustment for each beneficial owner as described above. To the knowledge of our Parent s directors and executive officers, as of May 1, 2008, no person, firm or corporation own, directly or indirectly, or exercise control or direction over voting securities carrying more than 5% of the voting rights attached to any class of our Parent s voting securities, except as indicated in the below.

Name and Address of Beneficial Owner (1)	**Amount and Nature of Beneficial Ownership**	**Percent Common Shares Outstanding**
Our greater than 5% shareholders:		
Chesapeake Energy Corporation (2) 6100 North Western Avenue, Oklahoma City, OK 73118	33,908,836	16.3%
Palo Alto Investors, LLC (2) 470 University Avenue, Palo Alto, CA 94301	23,876,100	11.5%
Ospraie Management, LLC (2) 320 Park Avenue, 27th Floor, New York, NY 10022	18,308,100	8.8%
GeoStar Corporation (3) 2480 W. Campus Drive, Building C, Mt. Pleasant, MI 48858	15,767,524	7.6%
Parent Directors, who are not employees: (4)		
Abby F. Badwi (5)	441,667	*
Robert D. Penner		*
John M. Selser Sr. (6)	50,000	*
Parent named executive officers: (4)		
J. Russell Porter, Chairman, President, Chief Executive Officer and Chief Operating Officer (7)	3,605,000	1.7%
Michael A. Gerlich, Vice President and Chief Financial Officer (8)	425,000	*
Jeffery C. Pettit, Vice President, Chief Operating Officer		*
Directors and named executive officers, as a group (6 persons)	4,521,667	2.1%

* Less than 1%.

(1) Unless otherwise indicated and subject to community property laws where applicable, management believes that all persons named in the following table have sole voting and investment power over all common shares reported as beneficially owned by them.

(2) Consists of common shares owned directly.

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(3) The number of common shares shown as beneficially owned by GeoStar is based on its most recent Form 13D filing with the SEC dated July 24, 2006. We have reasons to believe that GeoStar beneficially owns significantly less than 5% of our Parent s outstanding common shares.

(4) The contact address for our Parent s directors and named executive officers is 1331 Lamar Street, Suite 1080, Houston, Texas 77010.

(5) Consists of 441,667 common shares underlying stock options that currently are vested or will vest or be exercisable within 60 days of March 10, 2008 regardless of price.

(6) Consists of 50,000 common shares underlying stock options that currently are vested or will vest or be exercisable within 60 days of March 10, 2008 regardless of price.

(7) Consists of 2,280,000 common shares owned directly and 1,325,000 common shares underlying stock options that currently are vested or will vest or be exercisable within 60 days of March 10, 2008 regardless of price.

(8) Consists of 25,000 common shares owned directly and 400,000 common shares underlying stock options that currently are vested or will vest or be exercisable within 60 days of March 10, 2008 regardless of price.

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MANAGEMENT

Parent

Our Parent s directors, executive officers, who are also referred to as named executive officers, and certain other significant employees and their ages as of May 1, 2008 are as follows:

Name	Age	Position
J. Russell Porter*	46	Chairman, President, Chief Executive Officer and Director
Michael A. Gerlich*	54	Vice President and Chief Financial Officer
Jeffery C. Pettit*	50	Vice President and Chief Operating Officer
Henry J. Hansen	52	Vice President of Land
Frederick E. Beck, PhD	48	Vice President of Drilling
R. David Rhodes	49	Vice President of Completion and Production
Sara-Lane Sirey	40	General Corporate Canadian Counsel and Corporate Secretary
Abby F. Badwi	61	Director
Robert D. Penner	63	Director
John M. Selser Sr.	49	Director

* Named executive officer.

J. Russell Porter has been a member of our Parent s Board of Directors and has served as our Parent s President and Chief Executive Officer since February 2004 and was appointed Chairman of the Board in August 2006. From September 2000 to February 2004, he served as Chief Operating Officer and as an officer of GeoStar Corporation. Mr. Porter has an energy focused background, with approximately 17 years of natural gas and oil exploration and production experience and five years of banking and investment experience specializing in the energy sector. From April 1994 to September 2000, Mr. Porter served as an Executive Vice President of Forcenergy, Inc., a publicly traded exploration and production company, where he was responsible for the acquisition and financing of the majority of its assets across the United States and Australia. He currently is a director of Caza Oil & Gas, Inc., a publicly traded exploration and development company listed on the Toronto Stock Exchange and the London AIM exchange. Mr. Porter holds a Bachelor of Science degree in Petroleum Land Management from Louisiana State University and a MBA from the Kenan-Flagler School of Business at the University of North Carolina at Chapel Hill.

Michael A. Gerlich joined our Parent in May 2005, as Vice President and Chief Financial Officer. Mr. Gerlich has over 27 years of natural gas and oil accounting and finance experience. From 1994 until joining our Parent, Mr. Gerlich served as Senior Vice President Accounting and Finance for Calpine Natural Gas L.P., formerly known as Sheridan Energy, Inc., where he served as Vice President and Chief Financial Officer. Over a 10-year period prior to joining Sheridan Energy, Mr. Gerlich held various accounting and finance positions with Trinity Resources, Ltd., with his last position being Executive Vice President and Chief Financial Officer. Mr. Gerlich was also with a Big Four accounting firm, where the focus of his practice was with energy related clients. Mr. Gerlich is a Certified Public Accountant and graduated with honors from Texas A&M University with a Bachelor of Business Administration degree in Accounting.

Jeffery C. Pettit joined our Parent in August 2007, as Vice President and Chief Operating Officer. Mr. Pettit has over 28 years of natural gas and oil operational experience. Prior to joining our Parent, Mr. Pettit was General Manager-Gulf Coast Operations and Engineering with Dominion E&P. He joined Dominion in 2001 and held positions as Joint Interest Manager and General Manager Coalbed Methane. Previous to his service at Dominion, Mr. Pettit worked as a private engineering consultant for several independent oil and gas companies. During the twenty year period from 1979 until 1999, his employment included various operations, acquisitions, and reservoir engineering management positions with Burlington Resources, LL&E, Inexco Oil Company and Pennzoil. Mr. Pettit holds a Bachelor of Science degree in Petroleum Engineering from Mississippi State University.

Henry J. Hansen joined our Parent in September 2005, as Vice President of Land. Mr. Hansen has over 28 years of land management experience. Prior to joining our Parent, Mr. Hansen was Rocky Mountain Land Manager with El Paso Corporation from 1999 until January 2003. He returned to El Paso Corporation in June 2004, where he was senior landman until joining Gastar in September 2005. Mr. Hansen graduated from the University of Texas at Austin, Texas with a Bachelor of Business Administration in Petroleum Management.

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Frederick E. Beck, PhD joined our Parent in April 2002, as Vice President of Drilling. Dr. Beck has over 25 years of diversified experience in the natural gas and oil business. He has held positions with a major operator as a drilling engineer, drilling supervisor and as an assistant professor of petroleum engineering at the New Mexico School of Mines. From 1996 and prior to joining our Parent as Vice President of Operations, Dr. Beck was Vice President of the turnkey drilling division of Nabors Drilling USA LP. Dr. Beck holds a Bachelor of Science degree in Geology, Master of Science degree in Petroleum Engineering and Doctor of Philosophy Degree in Petroleum Engineering, all from Louisiana State University in Baton Rouge, Louisiana.

R. David Rhodes joined our Parent in March 2006, as Vice President of Completion and Production. Mr. Rhodes has over 25 years of petroleum engineering experience, focused primarily in the supervision and management of completion and production operations. Prior to joining our Parent, he managed Oil & Gas Operations and Consulting, Inc., an independent consulting firm he established in May 2001, where he worked as a petroleum engineering consultant for numerous natural gas and oil operators including our Parent. Mr. Rhodes continues to maintain his relationship with Oil & Gas Operations and Consulting, Inc. From 1981 to 2001, Mr. Rhodes held various engineering and management/supervisory positions at Getty Oil Company and Marathon Oil Company (formerly Texas Oil & Gas Company). His last position was Operations Manager for East Texas and Northern Louisiana. Mr. Rhodes holds a Bachelor of Science degree in Petroleum Engineering from Louisiana Tech University.

Sara-Lane Sirey, LLB is an attorney in private practice, who has served as the Corporate Secretary of our Parent and General Corporate Canadian Counsel since May 2000. From July 1993 to April 2001, she served as an attorney at the law firm of Armstrong Perkins Hudson LLP (formerly Ogilvie and Company) in Calgary, Alberta, Canada, becoming a partner in 1999. Specializing in corporate/securities law, she has acted for issuers, in all industry segments, in Canada, the United States and internationally, focusing on corporate reorganizations, commercial transactions and initial public offerings of junior emerging companies as well as equity and debt financings, mergers and acquisitions and commercial transactions of senior established companies. Ms. Sirey obtained her Bachelor of Laws degree at the University of Saskatchewan.

Abby F. Badwi has been a member of our Parent s Board of Directors since February 2004. Mr. Badwi is an international energy executive with more than 30 years of experience in the exploration, development and production of natural gas and oil fields in North America, South America, Asia, Europe and the Middle East. He currently is Chief Executive and Director of Bankers Petroleum, a Canadian public exploration and production company listed on the TSX and London AIM Exchange with operations in Europe and the USA. From July 2005 to September 2007, he was President, Chief Executive Officer and director of Rally Energy Corp., a public Canadian natural gas and oil company listed on the TSX and the Frankfurt Stock Exchange with operations in Egypt, Pakistan and Canada. Prior to joining Rally Energy, he was the President of Corrundum Energy Ltd, a private natural gas and oil investment and advisory firm from 2003 until 2005. From 2000 until 2003, he was President and CEO of Geodyne Energy Inc., a natural gas and oil venture publicly traded on Canada s TSX Venture Exchange. Mr. Badwi has been an officer of several Canadian public and private companies, including President and Chief Operating Officer of Carmanah Resources Ltd., a Calgary, Alberta-based company with oil holdings in Canada, Indonesia and Venezuela, and Vice President International Exploration of Sceptre Resources Limited, an natural gas and oil exploration and production company. He is currently a director of Sustainable Energy Technologies Ltd. and Fairmount Energy Inc., both listed on Canada s TSX Venture Exchange. Mr. Badwi holds a Bachelor of Science degree in petroleum geology from the University of Alexandria, Egypt.

Robert D. Penner became a member of our Parent s Board of Directors effective July 16, 2007. Mr. Penner retired from his position as a senior partner with KPMG in 2004, after a career of advising public and private clients on tax and accounting matters for almost 40 years. He currently serves on the Board of Directors for Corridor Resources Ltd, Storm Cat Energy Corporation, Sustainable Energy Technologies Ltd., Terra Energy Corp. and Unbridled Energy Corporation as well as serving on the Board of Directors or as Executor/Trustee for several private companies and family trusts.

John M. Selser Sr. became a member of our Parent s Board of Directors effective March 30, 2007. He has been a partner at Maple Leaf Partners, a Baton Rouge, Louisiana based hedge fund since 2003. From 1992 to 2003, Mr. Selser was an energy equity analyst for several sell-side firms. From 1984 to 1991, Mr. Selser was a petroleum engineer for major oil companies in various domestic drilling, production and reservoir engineering assignments. Mr. Selser holds a Bachelor of Science in both Civil Engineering and Petroleum Engineering from Louisiana State University, Baton Rouge, Louisiana and a Masters of Business Administration from Tulane University, New Orleans, Louisiana.

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Each of our Parent s directors holds office until the next annual meeting of shareholders or until the director resigns or is removed by actions of the board. Of our Parent s directors, Messrs. Porter and Selser are citizens of the United States, while Messrs. Badwi and Penner are citizens of Canada. There are no family relationships between any of our Parent s directors or executive officers.

Code of Ethics

Our Parent adopted a Code of Ethics on December 15, 2005. A copy of our Code of Ethics for all employees was filed as an exhibit to our Registration Statement on Form S-1/A on December 22, 2005 and is available on our website at **www.gastar.com**. A copy of our Parent s Code of Ethics will be provided to any person without charge, upon request. Such requests should be directed to J. Russell Porter, President and Chief Executive Officer, 1331 Lamar Street, Suite 1080, Houston, Texas 77010.

Shareholders or other interested parties may send communications to the Board of Directors by writing through the Secretary of the Company at 1331 Lamar Street, Suite 1080, Houston, Texas 77010. The Secretary will forward to the directors all communications that, in his or her judgment, are appropriate for consideration by the directors. Comments or complaints relating to our accounting, internal accounting controls or auditing matters will also be referred to members of the Audit Committee. The Audit Committee has procedures for (a) receipt, retention and treatment of complaints received by us regarding accounting, internal accounting controls, or auditing matters and (b) the confidential, anonymous submission by our employees of concerns regarding questionable accounting or auditing matters. The Whistleblower procedure adopted by the Audit Committee is available on our website at www.gastar.com.

Audit Committee

Our Parent has a separately-designated standing Audit Committee, which currently is comprised of Messrs. Badwi, Penner (chairman) and Selser. After reviewing the qualifications of the current members of the Audit Committee, our Parent s Board of Directors has determined that all current Audit Committee members are independent , as that concept is defined in Section 10A of the Exchange Act, and the applicable rules of the American Stock Exchange. Our Parent s Board of Directors also determined that all current Audit Committee members are financially literate and that Mr. Penner is a financial expert under the applicable rules of the Exchange Act. In accordance with its Terms of Reference, the Audit Committee examines and reviews on behalf of the Board of Directors, internal financial controls, financial and accounting policies and practices, related party transactions and the form and content of financial reports and statements. The Audit Committee is responsible for the hiring, overseeing and terminating the independent accountants engaged to prepare any audit or issue any audit report, and the work of the external auditors. The Chief Financial Officer attends the meetings of the Audit Committee by invitation.

On March 15, 2007, our Parent notified the American Stock Exchange that we were not in compliance with the American Stock Exchange Company Guide Rule 121(B)(2)(a), which requires that each listed company must have, and certify that it has and will continue to have, an audit committee of at least three independent members. As a result of an independent member of our Audit Committee not standing for reelection at our 2006 annual meeting of shareholders, the Audit Committee was left with two independent members, one of whom remains designated as its financial expert . On July 16, 2007, our Parent announced that Mr. Robert D. Penner had been appointed a director and a member of the Audit Committee, bringing our Parent into compliance with the American Stock Exchange Company Guide Rule.

Notwithstanding our Parent s temporary non-compliance with the American Stock Exchange rule regarding the number of independent directors serving on the Audit Committee, at all times since January 4, 2006, the date our Parent first became listed and subject to the reporting requirements of the Exchange Act, as amended, our Parent s Audit Committee has consisted solely of directors meeting the independence requirements of the American Stock Exchange and Section 10A of the Exchange Act.

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The Compensation Committee

The compensation committee of our Parent s Board of Directors, which we refer to as the Remuneration Committee, is currently comprised of Messrs. Badwi (Chairman), Crow, Penner and Selser.

None of our Parent s executive officers serves as a member of the board of directors or compensation committee (or committee performing similar functions) of any other entity, one or more of whose executive officers serve on our Parent s Board of Directors or Remuneration Committee.

Issuer

Issuer s board of directors is comprised of a sole director, J. Russell Porter who is reelected annually. Members of Issuer s board of directors receive no compensation for their board duties. Issuer s executive officers are J. Russell Porter (President) and Michael A. Gerlich (Secretary and Treasurer).

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COMPENSATION DISCUSSION AND ANALYSIS

The following Compensation Discussion and Analysis explains the compensation objectives, philosophy and practices of our Parent, with respect to its Chief Executive Officer, Chief Financial Officer and Chief Operating Officer, who are referred to as named executive officers. These individuals are our Parent s only executive officers. For purposes of this discussion, the terms we, us , our and the Company refer to our Parent, Gastar Exploration Ltd.

Compensation Philosophy

Our compensation programs for our named executive officers are designed to achieve the following objectives:

- Attract and retain highly talented individuals who will engage in behavior essential to our success;
- Motivate and reward employee performance that is critical to our success;
- Align the interests of our named executive officers and our shareholders by motivating our named executive officers to increase shareholder value and rewarding them based on operational and financial success and when shareholder value increases; and
- Balance annual cash payments and longer term equity compensation.

Our executive compensation is structured to achieve these goals through our mix of short-term cash payments and long-term equity compensation.

Elements of Executive Compensation and Rationale

There are three key elements to our compensation: base salary, annual cash bonus awards and stock-based compensation. We believe that a combination of these three elements balances rewards for current performance and longer term corporate objectives as measured, among other things, by operational successes, common share performance and creation of shareholder value. The terms of the named executive officers employment, including their compensation and other benefits, are set forth in employment agreements, described below.

Role of the Remuneration Committee, its Consultant and Management

Executive compensation is the responsibility of the Remuneration Committee (for purposes of this analysis, the Committee). The Committee operates under a written charter, or the Terms of Reference , adopted by the Board of Directors. Abby F. Badwi, Robert D. Penner and John M. Selser Sr. are members of the Board of Directors and members of the Committee. Mr. Badwi is the Committee Chairman. Each member of the Committee qualifies as an independent director under the American Stock Exchange listing standards and under the Exchange Act.

The aim of the Committee is to award and compensate officers and employees in a manner which provides incentives for the enhancement of shareholder value, for the successful implementation of the Company s business plan and for continuous improvement in corporate and personal performance. The compensation program is based on a pay-for-performance philosophy.

The Committee reviews and recommends the compensation philosophy and guidelines for the Company, which include reviewing the compensation philosophy and guidelines (a) for executive management, for recommendation to the Board for its consideration and approval, and (b) relating to all employees, including annual salary and incentive policies and programs, and material new benefit programs or material changes to existing benefit programs.

During 2007, the Committee engaged Thomas J. Reno & Associates, Inc. (TJR), a consulting firm experienced in executive compensation, which has access to national compensation surveys and our compensation information. TJR s responsibilities include

Providing recommendations on compensation based on review of the compensation of our peer group (as described below);

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Gathering and analyzing publicly available proxy data from the peer group and other peer group data;

Analyzing pay survey data and analyses provided by our management;

Reviewing and advising on the performance measures to be used in bonus formulas and equity awards; and

Reviewing and advising on target bonus levels, actual year end bonus calculations and the design and size of equity awards.

These peer companies reviewed by TJR included Abraxas Petroleum Corp., Exploration Company of Delaware, Gasco Energy Inc., GMX Resources Inc., Harvest Natural resources Inc., NGAS Resources Inc., Toreador Resources Corp., Transmeridian Exploration Inc. and Warren Resources Inc. TJR reviewed the amount or form of executive and director compensation, as well as periodic detailed analyses of peer group executive salaries, cash bonus awards and other incentive compensation bonus awards and other incentive compensation awards, such as stock options and restricted common stock grants. This information is used by the Committee to insure that base salaries and other benefits are reasonable and competitive with those offered by our peer group to their executives.

Our Chief Executive Officer also plays an important role in the executive compensation process and is closely involved in assessing the performance of our named executive officers and making recommendations regarding base salary, bonus targets, performance measures and weighting and equity compensation for these executive officers. The compensation of our Chief Financial Officer and Chief Operating Officer is determined by the Committee, after receiving the recommendations of the Chief Executive Officer as to what he considers to be fair compensation for our named executive officers. The recommendations are based on an assessment of the Chief Financial Officer s and Chief Operating Officer s responsibilities and performance, the Company s performance and the market in which the Company competes for executive talent. The Chief Executive Officer attends those portions of the meetings of the Committee that are related to the Chief Financial Officer s and Chief Operating Officer s compensation. The compensation of our Chief Executive Officer is determined by the Committee. In determining the compensation of the Chief Executive Officer, the Committee takes into account the Chief Executive Officer s responsibilities and performance, the Company s performance and the market in which the Company competes for executive talent. The Chief Executive Officer does not attend any meetings related to his compensation.

Our Chief Financial Officer also plays an important role in our executive compensation process. Our Chief Financial Officer makes recommendations to the Committee regarding the structure of the annual cash bonus awards program and the size of such awards. These recommendations are drawn from our Chief Financial Officer s previous work experience and informal surveys of the annual cash bonus programs of other similar sized companies and other oil and natural gas companies.

Benchmarking of Compensation

When making compensation decisions, we also look to the compensation of our named executive officers relative to the compensation paid to similarly-situated executives at other organizations that are similar in size and operations to us. During 2007, TJR provided us with competitive compensation data from our peer group as well as business and technical considerations. In 2007, we used three primary resources to identify competitive compensation relevant to our named executive officers:

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