GeoMet, Inc.
Form S-1/A
May 12, 2006
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As filed with the Securities and Exchange Commission on May 12, 2006

Registration No. 333-131716

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Amendment No. 2

to

Form S-1

REGISTRATION STATEMENT

UNDER

THE SECURITIES ACT OF 1933

GeoMet, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**1311**	**76-0662382**
(State or other jurisdiction of incorporation or organization)	***(Primary Standard Industrial Classification Code Number)***	***(I.R.S. Employer Identification Number)***

909 Fannin, Suite 3208

Houston, TX 77010

(713) 659-3855

(Address, including zip code, and telephone number, including area code, of registrant s principal executive offices)

J. Darby Seré

Chairman, President and Chief Executive Officer

GeoMet Inc.

909 Fannin, Suite 3208

Houston, TX 77010

(713) 659-3855

(Name, address, including zip code, and telephone number, including area code, of agent for service)

Copies to:

Dallas Parker

William T. Heller IV

Thompson & Knight LLP

333 Clay Street, Suite 3300

Houston, TX 77002

(713) 654-8111

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

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

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

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

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

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 or until this registration statement shall become effective on such date as the Commission, acting pursuant to said Section 8(a), may determine.

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The information in this prospectus is not complete and may be changed. These securities may not be sold 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 offers to buy these securities in any jurisdiction where the offer or sale is not permitted.

SUBJECT TO COMPLETION, DATED MAY 12, 2006

PROSPECTUS

10,250,000 Shares

Common Stock

This prospectus relates to up to 10,250,000 shares of the common stock of GeoMet, Inc., which may be offered and sold, from time to time, by the selling stockholders named in this prospectus. The selling stockholders acquired the shares of common stock offered by this prospectus in a private equity placement. We are registering the offer and sale of the shares of common stock to satisfy registration rights we have granted to the selling stockholders. We are not selling any shares of common stock under this prospectus and will not receive any proceeds from the sale of common stock by the selling stockholders.

The shares of common stock to which this prospectus relates may be offered and sold from time to time directly by the selling stockholders or alternatively through underwriters or broker-dealers or agents. The shares of common stock may be sold in one or more transactions, at fixed prices, at prevailing market prices at the time of sale, or at negotiated prices. Prior to this offering, there has been no public market for the common stock. We estimate that the selling stockholders initially will sell their shares at prices between $ per share and $ per share, if any shares are sold. Future prices will likely vary from this range and initial sales may not be indicative of prices at which our common stock will trade in the future. Please read Plan of Distribution.

Investing in our common stock involves risks. You should read the section entitled Risk Factors beginning on page 10 for a discussion of certain risks that you should consider before buying shares of our common stock.

You should rely only on the information contained in this prospectus or any prospectus supplement or amendment. We have not authorized anyone to provide you with different information. We are not making an offer of these securities in any state where the offer is not permitted.

Neither the Securities and Exchange Commission nor any other regulatory body has approved or disapproved of these securities or passed upon the accuracy or adequacy of this prospectus. Any representation to the contrary is a criminal offense.

The date of this prospectus is , 2006

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WHERE YOU CAN FIND INFORMATION

We have filed with the SEC, under the Securities Act, a registration statement on Form S-1 with respect to the common stock offered by this prospectus. This prospectus, which constitutes part of the registration statement, does not contain all of the information set forth in the registration statement or the exhibits and schedules which are part of the registration statement, portions of which are omitted as permitted by the rules and regulations of the SEC. Statements made in this prospectus regarding the contents of any contract or other documents are summaries of the material terms of the contract or document. With respect to each contract or document filed as an exhibit to the registration statement, reference is made to the corresponding exhibit. For further information pertaining to us and to the common stock offered by this prospectus, reference is made to the registration statement, including the exhibits and schedules thereto, copies of which may be inspected without charge at the public reference facilities of the SEC at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. Copies of all or any portion of the registration statement may also be obtained by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains a web site that contains reports, proxy and information statements, and other information that is filed electronically with the SEC. The web site can be accessed at www.sec.gov.

After effectiveness of the registration statement, which includes this prospectus, we will be required to comply with the requirements of the Securities Exchange Act of 1934, as amended (the Exchange Act), and, accordingly, will file current reports on Form 8-K, quarterly reports on Form 10-Q, annual reports on Form 10-K, and other information with the SEC. Those reports and other information will be available for inspection and copying at the public reference facilities and internet site of the SEC referred to above.

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SUMMARY

This summary highlights selected information from this prospectus but does not contain all information that you should consider before investing in our common stock. You should read this entire prospectus carefully, including Risk Factors beginning on page 10, and the financial statements included elsewhere in this prospectus. In this prospectus, we refer to GeoMet, Inc., its subsidiaries and predecessors as GeoMet, we, our, or our company. References to the number of shares of our common stock outstanding have been revised to reflect a four-for-one stock split effected in January 2006. The estimates of our proved reserves as of December 31, 2005, 2004 and 2003 included in this prospectus are based on reserve reports prepared by DeGolyer and MacNaughton, independent petroleum engineers. A summary of their report with respect to our estimated proved reserves as of December 31, 2005 is attached to this prospectus as Appendix A. We discuss sales volumes, per Mcf revenue, per Mcf cost and other data in this prospectus net of any royalty owner s interest. We have provided definitions for some of the industry terms used in this prospectus in the Glossary of Natural Gas and Coal Terms.

About GeoMet

We are engaged in the exploration, development, and production of natural gas from coal seams (coalbed methane or CBM). Our principal operations and producing properties are located in the Cahaba Basin in Alabama and the Appalachian Basin in West Virginia and Virginia. We were originally founded as a consulting company to the coalbed methane industry in 1985 and have been active as an operator and developer of coalbed methane properties since 1993. We control a total of approximately 255,000 net acres of coalbed methane development rights, primarily in Alabama, West Virginia, Virginia, Louisiana, Colorado, and British Columbia. We are currently developing a total of approximately 77,000 net acres of coalbed methane development rights in the Gurnee field in the Cahaba Basin and in the Pond Creek field in the Appalachian Basin. We also control the balance of approximately 178,000 net acres of coalbed methane exploration and development rights primarily in north central Louisiana, British Columbia, West Virginia, and Colorado. We have conducted substantial gas desorption testing and drilling of core holes throughout our property base. We believe our extensive undeveloped acreage position in the Gurnee field in the Cahaba Basin and in the Pond Creek field in the Appalachian Basin contains a total of 586 additional drilling locations.

At December 31, 2005, we had 262.5 Bcf of estimated proved reserves with a PV-10 of approximately $880 million using gas prices in effect at such date. See Selected Historical Consolidated Financial and Operating Data Reconciliation of Non-GAAP Financial Measures for additional information regarding PV-10. Our estimated proved reserves at December 31, 2005 were 100% coalbed methane and 74% proved developed. For the month of March 2006, our net gas sales averaged approximately 15,500 Mcf per day. Our development expenditures for the development of the Gurnee and Pond Creek fields were approximately $46.4 million in 2005. We intend to increase our development expenditures by approximately 57% in 2006 to approximately $72 million to accelerate the drilling of the Gurnee and Pond Creek fields. For 2006, we estimate that our total capital expenditures will be approximately $90 million.

Areas of Operation

Cahaba Basin

We have the development rights to approximately 41,800 net CBM acres throughout the Cahaba Basin of central Alabama, which is adjacent to the Black Warrior Basin. At December 31, 2005, approximately 55% of our estimated proved reserves, or 145.1 Bcf, were located in the Gurnee field within the Cahaba Basin, of which approximately 78% were classified as proved developed. At December 31, 2005, we had developed

24% of our

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Cahaba Basin CBM acreage. We own a 100% working interest in the area and are the operator. Net daily sales of gas averaged approximately 4,400 Mcf for the month of March 2006. In 2006, we intend to spend approximately $45 million of our capital expenditure budget to develop and drill approximately 75 wells and expand our facilities in the Cahaba Basin.

We have constructed and operate an approximate 38.5-mile pipeline from the Cahaba Basin to the Black Warrior River for the disposal of produced water under a permit issued by the Alabama Department of Environmental Management. We also operate a water treatment facility in the Gurnee field to condition the produced water prior to injection into the pipeline and a discharge pond at the river to aerate the water prior to disposal. We believe that these facilities will meet all of our future water disposal requirements for the Gurnee field.

We control and operate a 9.2-mile, 12-inch high-pressure steel pipeline and a gas treatment and compression facility through which we gather, dehydrate, and compress our gas for delivery into the Southern Natural Gas pipeline system.

Appalachian Basin

In the Appalachian Basin of southern West Virginia and southwestern Virginia, we have the rights to develop approximately 56,000 net CBM acres, approximately 35,000 of which are in our Pond Creek field. At December 31, 2005, approximately 44% of our estimated proved reserves, or 114.5 Bcf, were located within the Pond Creek field, of which approximately 70% were classified as proved developed. We own a 100% working interest in the area and are the operator. Net sales of gas averaged approximately 9,900 Mcf for the month of March 2006. In 2006, we intend to spend approximately $20 million of our capital expenditure budget to develop and drill approximately 40 wells in the Pond Creek field.

CBM wells in the Pond Creek field produce comparatively lower levels of water. Produced water is either used in our operations or injected into a disposal well that we own and operate. We believe this disposal well will meet our future water disposal requirements in the Pond Creek field.

Our gas is gathered into our central dehydration and compression facility and delivered into the Cardinal States Gathering System for redelivery into the Columbia Gas Transmission Corporation gas pipeline system.

British Columbia

Our Peace River Project is comprised of approximately 33,000 gross acres (16,500 net acres) along the Peace River near Hudson s Hope, British Columbia. We are conducting operations on this project through an exploration and development agreement with a third party. We will earn a 50% working interest in this leasehold by spending $7.2 million on an evaluation program. We have spent approximately $5.5 million of this amount from project inception through December 31, 2005. We expect to complete our earning obligations in 2006 and to operate this project going forward. We have drilled three core holes targeting the Lower Cretaceous Gething Coal Formation. We believe that the gas content and coal thickness under our acreage are favorable for CBM development. We have recently completed two production test wells and a water disposal well, and testing operations are in process.

North Central Louisiana

In Winn, LaSalle, and Caldwell Parishes of Louisiana, we are conducting an evaluation of the coals within the Wilcox formation. We operate the project with a 100% working interest. As of December 31, 2005, we had a total of approximately 119,000 net acres under lease. We have drilled 17 exploration or production test wells and

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two water disposal wells. We have also conducted 60 gas desorption tests from a sample of nine of these wells to determine the gas content of the coal and to define the potential gas resources. We believe that the gas content and coal thickness under our acreage position are favorable for CBM development. We are currently evaluating producibility issues related to zonal isolation of adjacent water sands and related water encroachment in this area.

Piceance Basin of Colorado

We hold a total of approximately 16,949 net CBM acres of leasehold in the Piceance Basin in Mesa County, Colorado, of which approximately 14,600 net CBM acres are located in our Cameo prospect in the southwestern portion of the Piceance Basin. We have drilled one core hole and have conducted desorption tests on the core. We believe that the gas content and coal thickness under our acreage position are favorable for CBM development. We are actively pursuing opportunities to increase our acreage position in this area.

Characteristics of Coalbed Methane

The source rock in conventional natural gas is usually different from the reservoir rock, while in coalbed methane the coal seam serves as both the source rock and the reservoir rock. The storage mechanism is also different. Gas is stored in the pore or void space of the rock in conventional natural gas, but in coalbed methane, most, and frequently all, of the gas is stored by adsorption. Adsorption allows large quantities of gas to be stored at relatively low pressures. A unique characteristic of coalbed methane is that the gas flow can be increased by reducing the reservoir pressure. Frequently the coalbed pore space, which is in the form of cleats or fractures, is filled with water. The reservoir pressure is reduced by pumping out the water, releasing the methane from the molecular structure, which allows the methane to flow through the cleat structure to the well bore. While a conventional natural gas well typically decreases in flow as the reservoir pressure is drawn down, a coalbed methane well will typically increase in production for up to five years depending on well spacing.

Coalbed methane and conventional natural gas both have methane as their major component. While conventional natural gas often has more complex hydrocarbon gases, coalbed methane rarely has more than 2% of the more complex hydrocarbons. In the eastern coal fields of the United States, coalbed methane is generally 98 to 99% pure methane and requires only dehydration of the gas to remove moisture to achieve pipeline quality. In the western coal fields of the United States, it is also sometimes necessary to strip out either carbon dioxide or nitrogen. Once coalbed methane has been produced, it is gathered, transported, marketed, and priced in the same manner as conventional natural gas.

The content of gas within a coal seam is measured through gas desorption testing. The ability to flow gas and water to the well bore in a coalbed methane well is determined by the fracture or cleat network in the coal. While at shallow depths of less than 500 feet these fractures are sometimes open enough to produce the fluids naturally, at greater depths the networks are progressively squeezed shut, reducing the ability to flow. It is necessary to provide other avenues of flow such as hydraulically fracturing the coal seam. By pumping fluids at high pressure, fractures are opened in the coal and a slurry of fluid and sand proppant is pumped into the fractures so that the fractures remain open after the release of pressure, thereby enhancing the flow of both water and gas to allow the economic production of gas.

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Summary of Our Properties as of December 31, 2005

Field	Estimated Proved Reserves(1) Proved (MMcf)	Proved Developed (MMcf)	PV-10(2) (In millions)
Appalachia:			
Pond Creek field	114,458	79,864	$ 366.3
Alabama:			
Gurnee field	145,062	112,517	496.6
White Oak Creek field	2,991	2,758	17.3
Total	262,511	195,139	$ 880.2

Area	Net Productive Wells(3)	Additional Drilling Locations(4)	Net CBM Acres Owned or Controlled Total	Developed	Undeveloped
Appalachian Basin	163	220	55,616	11,599	44,017
Cahaba Basin	132	366	41,766	10,120	31,646
North Central Louisiana	17		119,244		119,244
British Columbia	1		16,500		16,500
Piceance Basin			16,949		16,949
Other (United States)			4,790		4,790
Total	313	586	254,865	21,719	233,146

(1) Based on the reserve report prepared by DeGolyer and MacNaughton, independent petroleum engineers, a summary of which is attached to this prospectus as Appendix A.

(2) PV-10 was calculated using a natural gas price at December 31, 2005 of $9.66 per Mcf. See Selected Historical Consolidated Financial and Operating Data Reconciliation of Non-GAAP Financial Measures for additional information.

(3) Excludes nine net wells pending completion at December 31, 2005. Productive wells are wells in which we have a working interest and that are producing or are capable of producing natural gas.

(4) Additional known drilling locations in proved projects.

Recent Drilling Activity (net productive wells)

Year Ended December 31,

	2005(1)	2004	2003	2002
Development	93.0	81.8	47.7	9.6
Exploratory	5.0	10.0	15.0	2.5
Total	98.0	91.8	62.7	12.1
Total Capital Expenditures (in thousands)	$ 59,202	$ 86,189(2)	$ 36,069	$ 12,770

(1) Excludes nine net wells pending completion.
(2) Includes $27 million for the acquisition of producing properties.

Strategy

Our objective is to increase stockholder value by investing capital to increase our reserves, production, cash flow, and earnings. We intend to focus on the following strategies:

Focus exclusively on coalbed methane operations where we have substantial experience and expertise.

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Exploit our existing resource base by accelerating drilling in our projects and expanding into adjacent areas, thereby leveraging our knowledge of the area and our existing infrastructure and operating base.

Explore for large-scale CBM development opportunities both in our existing core areas and in other areas that we enter, where we intend to have operating control and the ability to reduce costs through economies of scale. We seek to be among the first companies in an area so that our costs of entry are less, large acreage positions can be established, and smaller incremental investments can be made to reduce our risk before larger expenditures are required.

Seek out opportunistic CBM producing property acquisitions.

Optimize financial flexibility by maintaining unused capacity under our bank revolving credit facility. We have entered into a new five-year, $150 million revolving credit facility with an initial $120 million borrowing base.

Competitive Strengths

CBM Is Our Only Business. We explore for, develop, and produce CBM exclusively. We believe that substantial expertise and experience is required to develop, produce, and operate coalbed methane fields in an efficient manner. We believe that the inherent geologic and production characteristics of coalbed methane offer significant operational advantages compared to conventional gas production, including:

Production Rates. Unlike conventional natural gas production, which typically declines after initial production is established, production from CBM wells typically increases for the first few years of their productive lives although eventual peak rates are often lower than those of typical conventional gas wells. CBM wells also generally decline at a shallow rate relative to typical conventional gas wells.

Low Geologic Risks. Most CBM areas are located in known coal basins where the coal resource has been evaluated for coal mining. These areas have extensive existing geologic information databases. The drilling of new coreholes and a limited number of production test wells reduces the geologic risk prior to committing large development expenditures.

Low Finding and Development Costs. Our finding and development costs have averaged $0.95 per Mcf for the three-year period ended December 31, 2005. These costs include estimated future development costs associated with proved undeveloped reserves.

Low Production Costs. In the early stage of CBM project development per unit operating costs are high because production is initially low and many of our costs are fixed. As production from a project increases and economies of scale are realized, the per unit operating costs typically decrease. Over the life of a project, we believe our average per unit operating costs will be lower than those of many conventional gas industry projects.

Long-lived Reserves. Because CBM wells have initial inclining production rates and low decline rates thereafter, CBM projects typically result in a reserve life that is significantly longer than many types of conventional gas production.

Highly Experienced Team of CBM Professionals. Our 24-person CBM management, professional, and project management team has an average of more than 16 years of CBM experience and has participated in the drilling and operation of more than 2,600 CBM wells worldwide since

1977.

Large Inventory of Organic Growth Opportunities. We have a total of over 255,000 net acres of CBM exploration and development rights, including almost 77,000 net undeveloped acres in our two development areas. We believe our extensive undeveloped acreage position in the Gurnee field in the Cahaba Basin and in the Pond Creek field in the Appalachian Basin provides us with a total of 586 additional drilling locations.

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Track Record of Success in Identifying and Exploiting Large Underdeveloped Resource Plays. We pursue those projects that leverage our CBM expertise to exploit underdeveloped resource potential where we believe we can improve on the prior performance of other operators. We have a history of developing large scale projects in multiple basins with low finding and development costs and low project life operating costs.

Minimal Water Disposal Issues. Unlike many CBM projects, water disposal is not a significant issue for us in the Gurnee field, where we have a pipeline in place to transport produced water for disposal into the Black Warrior River, or in the Pond Creek field, which produces comparatively low amounts of water and where we have an existing water disposal well that we believe is adequate for our needs.

Risks Affecting Our Business

Our ability to successfully leverage our competitive strengths and execute our strategy depends upon many factors and is subject to a variety of risks. For example, our ability to accelerate drilling on our properties and fund our 2006 capital budget depends, to a large extent, upon our ability to generate cash flow from operations at or above current levels, maintain borrowing capacity at or near current levels under our revolving credit facility, and the availability of future debt and equity financing at attractive prices. Our ability to fund CBM property acquisitions and compete for and retain the qualified personnel necessary to conduct our business is also dependent upon our financial resources. Changes in natural gas prices, which may affect both our cash flows and the value of our gas reserves, our ability to replace production through drilling activities, material adverse changes in our gas reserves due to factors other than gas pricing changes, drilling costs and other factors, many of which are beyond our control, may adversely affect our ability to fund our anticipated capital expenditures, pursue property acquisitions, and compete for qualified personnel, among other things. You are urged to read the section entitled Risk Factors for more information regarding these and other risks that may affect our business and our common stock.

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CORPORATE INFORMATION

During the first quarter of 2006, we completed a private equity offering of 10,250,000 shares of our common stock, consisting of 2,317,023 shares issued by us and 7,932,977 shares sold by certain of our existing stockholders, to qualified institutional buyers. We received aggregate consideration (before offering expenses of $850,000) of approximately $28.0 million, or $12.09 per share. We did not receive any proceeds from the shares sold by the selling stockholders. In addition, we received approximately $17.5 million from certain of the selling stockholders for repayment of loans from us, including accrued and unpaid interest thereon. We used the net proceeds from the offering, together with the proceeds from the repayment of the selling stockholders loans, to repay a portion of the borrowings under our credit facility and for general corporate purposes.

On April 14, 2005, GeoMet, Inc., an Alabama corporation (Old GeoMet), was merged with and into GeoMet Resources, Inc., a Delaware corporation (GeoMet), and we subsequently changed our name to GeoMet, Inc. We initially acquired 80% of the common stock of Old GeoMet on December 9, 2000 and subsequently acquired an additional 0.95% of Old GeoMet s common stock on November 17, 2004. Accordingly, the equity of the minority interests in Old GeoMet was shown in the consolidated financial statements as a minority interest prior to April 14, 2005. The merger and related acquisition of the minority interest in Old GeoMet improved our financial flexibility, simplified our capital structure, and by aligning the interests of all equity holders, created a corporate structure more suited to a sale, public offering or other liquidity alternative for equity holders. Prior to our acquisition of the remaining minority interest in Old GeoMet, Old GeoMet held all of our gas assets and was, therefore, the borrower under bank credit facilities secured by such assets. We provided financing, management and other services to Old GeoMet, and Old GeoMet owed us $40 million in senior subordinated debt that had been advanced to fund exploration and development projects. Our acquisition of Old GeoMet eliminated the senior subordinated debt owned to us, combined our management and other personnel with the assets held by Old GeoMet that we managed, aligned the interests of our respective equity holders, and simplified our overall corporate structure. As a consequence of the elimination of the senior subordinated debt, borrowing capacity increased and financial flexibility was improved. The alignment of the interests of equity holders simplified our planning with respect to various liquidity alternatives and, generally, made it easier for investors and others to understand our company.

Our corporate headquarters are located at 909 Fannin, Suite 3208, Houston, Texas 77010 and our telephone number is (713) 659-3855. Our corporate website address is *www.geometinc.com*. Our technical and operational headquarters are located at 5336 Stadium Trace Parkway, Suite 206, Birmingham, Alabama 35244.

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THE OFFERING

Common stock offered by the selling stockholders	10,250,000 shares.
Common stock to be outstanding after this offering(1)(2)	32,614,021 shares.
Use of proceeds	We will not receive any proceeds from sale of the shares of common stock offered in this prospectus.
Dividend policy	We do not anticipate that we will pay cash dividends in the foreseeable future. Our credit facility prohibits the payment of cash dividends.
Risk factors	For a discussion of factors you should consider in making an investment, see Risk Factors.

(1) Excludes options to purchase 1,770,990 shares of our common stock outstanding as of March 31, 2006, of which 1,682,990 were exercisable.
(2) Represents 29,974,664 shares outstanding on December 31, 2005, plus 2,317,023 shares issued in connection with a private equity offering in 2006, and 322,334 shares issued upon the exercise of stock options after year end.

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SUMMARY OF FINANCIAL, RESERVE AND OPERATING DATA

The following table shows our historical financial, reserve and operating data for, and as of the end of, each of the periods indicated. Our historical results are not necessarily indicative of the results that may be expected for any future period. The following data should be read in conjunction with Management s Discussion and Analysis of Results of Operations and Financial Condition and our consolidated financial statements and related notes included elsewhere in this prospectus.

	Years Ended December 31,		
	2005	2004	2003
	(In thousands, unless otherwise indicated)		
STATEMENT OF OPERATIONS AND COMPREHENSIVE INCOME DATA:			
Total revenues	$ 41,980	$ 20,924	$ 12,049
Lease operating expenses, compression and transportation expenses and production taxes	12,933	7,517	3,047
Depreciation, depletion and amortization	4,867	2,691	2,120
Research and development	609	278	432
General and administrative	3,208	2,513	1,370
Impairment of non-operating assets			8
Realized losses on derivative contracts	7,473	815	44
Unrealized losses (gains) from the change in market value of open derivative contracts	12,059	(542)	102
Income from operations	831	7,652	4,926
Other expenses and interest, net	3,839	920	144
Income tax provision (benefit)	(993)	2,312	1,651
Minority interest	(442)	584	571
Cumulative effect of change in accounting method			19
Net income (loss)	$ (1,573)	$ 3,836	$ 2,541
BALANCE SHEET DATA (at period end):			
Working capital (deficit)	$ (7,368)	$ (1,251)	$ 5,133
Total assets	$ 247,909	$ 142,090	$ 81,505
Long-term debt	$ 99,926	$ 51,513	$ 10,102
Stockholders equity	$ 95,422	$ 65,692	$ 52,754
OTHER DATA:			
Net cash provided by operating activities	$ 12,433	$ 10,580	$ 10,801
Net cash used in investing activities	$ (59,661)	$ (66,193)	$ (36,341)
Net cash provided by financing activities	$ 44,906	$ 50,192	$ 30,534
Capital expenditures	$ 59,817	$ 86,189	$ 36,069
Net sales volume (Bcf)	4.6	3.2	2.5
Average natural gas sales price ($ per Mcf)	$ 9.06	$ 6.12	$ 4.71
Average natural gas sales price ($ per Mcf) realized(1)	$ 7.43	$ 5.87	$ 4.69
Total production expenses ($ per Mcf)	$ 2.81	$ 2.36	$ 1.23
Expenses: ($ per Mcf)			
Lease operating expenses	$ 1.89	$ 1.60	$ 0.66
Compression and transportation expenses	$ .72	$ 0.61	$ 0.40
Production taxes	$ .20	$ 0.15	$ 0.17
Research and development	$ .13	$ 0.09	$ 0.17
General and administrative	$ .70	$ 0.79	$ 0.55
Depreciation, depletion & amortization	$ 1.06	$ 0.84	$ 0.85
Estimated proved reserves (Bcf)(2)	262.5	209.9	103.9
PV-10 ($ millions)(2)(3)	$ 880.2	$ 481.8	$ 236.9

Standardized measure of discounted future net cash flows ($ millions)	$ 632.7	$ 349.8	$ 172.5
Price used for PV-10 ($ per Mcf)(2)	$ 9.66	$ 6.21	$ 5.77
EBITDA (in millions)(3)	$ 6.1	$ 9.8	$ 6.5

(1) Average realized price includes the effects of realized losses on derivative contracts.

(2) Based on the reserve reports prepared by DeGolyer and MacNaughton, independent petroleum engineers, at each period end. The natural gas price used to compute PV-10 is volatile and may fluctuate widely. Refer to Risk Factors for a more complete discussion.

(3) See Selected Historical Financial and Operating Data Reconciliation of Non-GAAP Financial Measures for additional information.

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RISK FACTORS

You should consider carefully each of the risks described below, together with all of the other information contained in this prospectus, before deciding to invest in our common stock.

Risks Related To Our Business

Natural gas prices are volatile, and a decline primarily in natural gas prices would significantly affect our financial results and impede our growth.

Our revenue, profitability, and cash flow depend upon the prices and demand for natural gas. The market for natural gas is very volatile and even relatively modest drops in prices can significantly affect our financial results and impede our growth. Changes in natural gas prices have a significant impact on the value of our reserves and on our cash flow. Prices for natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for natural gas, market uncertainty and a variety of additional factors that are beyond our control, such as:

- the domestic and foreign supply of natural gas;
- the price of foreign imports;
- overall domestic and global economic conditions;
- the consumption pattern of industrial consumers, electricity generators, and residential users;
- weather conditions;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations;
- proximity and capacity of gas pipelines and other transportation facilities; and
- the price and availability of alternative fuels.

Many of these factors may be beyond our control. Because all of our estimated proved reserves as of December 31, 2005 were natural gas reserves, our financial results are sensitive to movements in natural gas prices. Earlier in this decade, natural gas prices were much lower than they are today. Lower natural gas prices may not only decrease our revenues on a per Mcf basis, but also may reduce the amount of natural gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs or if our estimates of development costs increase, production data factors change or our exploration results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our properties for impairments. We are required to perform impairment tests on our assets whenever events or changes in circumstances lead to a reduction of the estimated useful life or estimated future cash flows that would indicate that the carry amount may not be recoverable or whenever management s plans change with respect to those assets. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken.

We face uncertainties in estimating proved gas reserves, and inaccuracies in our estimates could result in lower than expected reserve quantities and a lower present value of our reserves.

Natural gas reserve engineering requires subjective estimates of underground accumulations of natural gas and assumptions concerning future natural gas prices, production levels, and operating and development costs. In addition, in the early stages of a coalbed methane project, it is difficult to predict the production curve of a coalbed methane field. The estimated production profile of a field in the early stage of operations may vary significantly from the actual production profile as the field matures. As a result, quantities of estimated proved reserves, projections of future production rates, and the timing of development expenditures may be incorrect. Over time, material changes to reserve estimates may be made, taking into account the results of actual drilling,

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testing, and production. Also, we make certain assumptions regarding future natural gas prices, production levels, and operating and development costs that may prove incorrect. Any significant variance from these assumptions to actual figures could greatly affect our estimates of our reserves, the economically recoverable quantities of natural gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery, and estimates of the future net cash flows. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of gas we ultimately recover being different from reserve estimates.

The present value of future net cash flows from our estimated proved reserves is not necessarily the same as the current market value of our estimated natural gas reserves. We base the estimated discounted future net cash flows from our estimated proved reserves on current prices and costs. However, actual future net cash flows from our gas properties also will be affected by factors such as:

- geological conditions;
- changes in governmental regulations and taxation;
- assumptions governing future prices;
- the amount and timing of actual production;
- future gas prices and operating costs; and
- capital costs of drilling new wells.

The timing of both our production and our incurrence of expenses in connection with the development and production of natural gas properties will affect the timing of actual future net cash flows from estimated proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

Unless we replace our natural gas reserves, our reserves and production will decline, which would adversely affect our business, financial condition, results of operations, and cash flows.

Producing natural gas reservoirs are typically characterized by declining production rates that vary depending upon reservoir characteristics and other factors. CBM production generally declines at a shallow rate after initial increases in production which result as a consequence of the dewatering process. The rate of decline from our existing wells may change in a manner different than we have estimated. Thus, our future natural gas reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find, or acquire additional reserves to replace our current and future production at acceptable costs.

We may be unable to obtain adequate acreage to develop additional large-scale projects.

To achieve economies of scale and produce gas economically, we need to acquire large acreage positions to reduce our per unit costs. There are a limited number of coalbed formations in North America that we believe are favorable for CBM development. We face competition when acquiring additional acreage, and we may be unable to find or acquire additional acreage at prices that are acceptable to us.

Our exploration and development activities may not be commercially successful.

The exploration for and production of natural gas involves numerous risks. The cost of drilling, completing, and operating wells for coalbed methane or other gas is often uncertain, and a number of factors can delay or prevent drilling operations or production, including:

- unexpected drilling conditions;

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- title problems;
- pressure or irregularities in geologic formations;
- equipment failures or repairs;
- fires or other accidents;
- adverse weather conditions;
- reductions in natural gas prices;
- pipeline ruptures; and
- unavailability or high cost of drilling rigs, other field services, and equipment.

Our future drilling activities may not be successful, and our drilling success rates could decline. Unsuccessful drilling activities could result in higher costs without any corresponding revenues.

We will require additional capital to fund our future activities. If we fail to obtain additional capital, we may not be able to implement fully our business plan, which could lead to a decline in reserves.

We depend on our ability to obtain financing beyond our cash flow from operations. Historically, we have financed our business plan and operations primarily with internally generated cash flow, bank borrowings, and issuances of common stock. Our future contractual commitments from January 1, 2006 through December 31, 2011 total $150 million and include debt service, operating lease obligations, firm transportation obligations and other obligations, collectively aggregating approximately $18 million during 2006, $25 million during 2007 to 2010, and $107 million during 2011 to 2012, when our existing credit facility matures. We also require capital to fund our drilling budget, which is expected to be $90 million for 2006. We will be required to meet our needs from our internally generated cash flow, debt financings, and equity financings.

If our revenues decrease as a result of lower natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. We may, from time to time, need to seek additional financing. Our revolving credit facility contains covenants restricting our ability to incur additional indebtedness without the consent of the lender. There can be no assurance that our lender will provide this consent or as to the availability or terms of any additional financing. If we incur additional debt, the related risks that we now face could intensify. A higher level of debt also increases the risk that we may default on our debt obligations. Our level of debt affects our operations in several important ways, including the following:

- a portion of our cash flow from operations is used to pay interest on borrowings;

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

- a leveraged financial position would make us more vulnerable to economic downturns and could limit our ability to withstand competitive pressures; and

- any debt that we incur under our revolving credit facility will be at variable rates which makes us vulnerable to increases in interest rates. For example, a 1% increase in interest rates based upon our debt outstanding as of December 31, 2005 would result in an additional $990,000 of interest expense.

Even if additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations or available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to exploration and development of our projects, which in turn could lead to a possible loss of properties and a decline in our natural gas reserves.

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Our credit facility contains a number of financial and other covenants, and our obligations under the credit facility are secured by substantially all of our assets. If we are unable to comply with these covenants, our lenders could accelerate the repayment of our indebtedness.

Our credit facility subjects us to a number of covenants that impose restrictions on us, including our ability to incur indebtedness and liens, make loans and investments, sell assets, engage in mergers, consolidations and acquisitions, enter into transactions with affiliates, or pay dividends on our common stock. We are also required by the terms of our credit facility to comply with certain financial ratios. Our credit facility also provides for periodic redeterminations of our borrowing base, which may affect our borrowing capacity. Our credit facility is secured by a lien on substantially all of our assets, including equity interests in our subsidiaries. A more detailed description of our credit facility is included in Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources and the footnotes to our consolidated financial statements included elsewhere in this prospectus.

A breach of any of the covenants imposed on us by the terms of our credit facility, including the financial covenants, could result in a default under such indebtedness. In the event of a default, the lenders could terminate their commitments to us, and they could accelerate the repayment of all of our indebtedness. In such case, we may not have sufficient funds to pay the total amount of accelerated obligations, and our lenders could proceed against the collateral securing the facility. Any acceleration in the repayment of our indebtedness or related foreclosure could adversely affect our business.

In addition, the borrowing base under our credit facility is redetermined semi-annually and may be redetermined at other times upon request by the lenders under certain circumstances. Redeterminations are based upon a number of factors, including commodity prices and reserve levels. The next scheduled redetermination is to occur as of June 30, 2006. Upon a redetermination, we could be required to repay a portion of our bank debt. We may not have sufficient funds to make such repayments, which could result in a default under the terms of the credit facility and an acceleration of our indebtedness.

Currently the vast majority of our producing properties are located in two counties in Alabama, one county in West Virginia, and one county in Virginia, making us vulnerable to risks associated with having our production concentrated in a few areas.

The vast majority of our producing properties are geographically concentrated in two counties in Alabama, one county in West Virginia, and one county in Virginia. As a result of this concentration, we may be disproportionately exposed to the impact of delays or interruptions of production from these wells caused by significant governmental regulation, transportation capacity constraints, curtailment of production, natural disasters, interruption of transportation of natural gas produced from the wells in these basins, or other events which impact these areas.

Our business depends on transportation facilities owned by others. Disruption of, capacity constraints in, or proximity to pipeline systems could limit our sales and increase our per unit costs of producing our gas.

We transport our gas to market by utilizing pipelines owned by others. If pipelines do not exist near our producing wells, if pipeline capacity is limited, or if pipeline capacity is unexpectedly disrupted, our gas sales could be limited and our transportation costs could increase, reducing our profitability. If we cannot access pipeline transportation, we may have to reduce our production of gas or vent our produced gas to the atmosphere because we do not have facilities to store excess inventory. If our sales are reduced because of transportation constraints, our revenues will be reduced, which will also increase our per unit costs.

Our gas from the Pond Creek field in the Appalachian Basin is gathered to a central facility that we own and operate to be dehydrated and compressed and delivered into the Cardinal States Gathering System (Cardinal States) for redelivery into Columbia s pipeline system. Our gathering agreement with Cardinal States terminates

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on April 30, 2007. In the event that by April 30, 2007 we are either unable to execute a long-term gathering agreement or enter into an extension with Cardinal States, or have not completed a connection to an alternate pipeline, we may temporarily be unable to transport gas from the Pond Creek field to the market, and our revenues would be adversely affected.

We operate in a highly competitive environment and many of our competitors have greater resources than we do.

The gas industry is intensely competitive and we compete with companies from various regions of the United States and Canada and may compete with foreign suppliers for domestic sales, many of whom are larger and have greater financial, technological, human and other resources. If we are unable to compete, our operating results and financial position may be adversely affected. For example, one of our competitive strengths is as a low-cost producer of gas. If our competitors can produce gas at a lower cost than us, it would effectively eliminate our competitive advantage in that area.

In addition, larger companies may be able to pay more to acquire new properties for future exploration, limiting our ability to replace gas we produce or to grow our production. Our ability to acquire additional properties and to discover new reserves also depends on our ability to evaluate and select suitable properties and to consummate these transactions in a highly competitive environment.

The coalbeds from which we produce gas frequently contain water that may hamper our ability to produce gas in commercial quantities or affect our profitability.

Unlike conventional natural gas production, coalbeds frequently contain water that must be removed in order for the gas to desorb from the coal and flow to the well bore. Our ability to remove and dispose of sufficient quantities of water from the coal seam will determine whether or not we can produce gas in commercial quantities. The cost of water disposal may affect our profitability.

We may face unanticipated water disposal costs.

Where water produced from our projects fails to meet the quality requirements of applicable regulatory agencies or our wells produce water in excess of the applicable volumetric permit limit, we may have to shut in wells, reduce drilling activities, or upgrade facilities. The costs to dispose of this produced water may increase if any of the following occur:

- we cannot obtain future permits from applicable regulatory agencies;
- water of lesser quality is produced;
- our wells produce excess water; or

new laws and regulations require water to be disposed of in a different manner.

Our operations in British Columbia present unique risks and uncertainties, different from or in addition to those we face in our domestic operations.

We conduct our operations in British Columbia through our wholly owned subsidiary, Hudson s Hope Gas Ltd. Our operations in British Columbia may be adversely affected by currency fluctuations. The expenses of such operations are payable in Canadian dollars. As a result, our Canadian operations are subject to risk of fluctuations in the relative value of the Canadian and United States dollars. Other risks of operations in Canada include, among other things, increases in taxes and governmental royalties and changes in laws and policies governing operations of foreign-based companies. Laws and policies of the United States affecting foreign trade and taxation may also adversely affect our operations in British Columbia.

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We may be unable to retain our existing senior management team and/or our key personnel that has expertise in coalbed methane extraction and our failure to continue to attract qualified new personnel could adversely affect our business.

Our business requires disciplined execution at all levels of our organization to ensure that we continually develop our reserves and produce gas at profitable levels. This execution requires an experienced and talented management and production team. If we were to lose the benefit of the experience, efforts and abilities of any of our key executives or the members of our team that have developed substantial expertise in coalbed methane extraction, our business could be adversely affected. We have not entered into, and do not expect to enter into employment agreements or non-competition agreements with any of our key employees, other than J. Darby Seré, our Chief Executive Officer and President, and William C. Rankin, our Executive Vice President and Chief Financial Officer. We do not maintain key person life insurance on any of our personnel. Our ability to manage our growth, if any, will require us to continue to train, motivate, and manage our employees and to attract, motivate, and retain additional qualified managerial and production personnel. Competition for these types of personnel is intense, and we may not be successful in attracting, assimilating, and retaining the personnel required to grow and operate our business profitably.

Government laws, regulations, and other legal requirements relating to protection of the environment, health and safety matters and others that govern our business increase our costs and may restrict our operations.

We are subject to laws, regulations and other legal requirements enacted or adopted by federal, state, local, and foreign authorities, relating to protection of the environment and health and safety matters, including those legal requirements that govern discharges of substances into the air and water, the management and disposal of hazardous substances and wastes, the clean-up of contaminated sites, groundwater quality and availability, plant and wildlife protection, reclamation and restoration of mining or drilling properties after mining or drilling is completed, control of surface subsidence from underground mining, and work practices related to employee health and safety. Complying with these requirements, including the terms of our permits, has had, and will continue to have, a significant effect on our respective costs of operations and competitive position. In addition, we could incur substantial costs, including clean-up costs, fines and civil or criminal sanctions, and third party damage claims for personal injury, property damage, wrongful death, or exposure to hazardous substances, as a result of violations of or liabilities under environmental and health and safety laws.

Additionally, the gas industry is subject to extensive legislation and regulation, which is under constant review for amendment or expansion. Any changes may affect, among other things, the pricing or marketing of gas production. State and local authorities regulate various aspects of gas drilling and production activities, including the drilling of wells (through permit and bonding requirements), the spacing of wells, the unitization or pooling of gas properties, environmental matters, safety standards, market sharing, and well site restoration. If we fail to comply with statutes and regulations, we may be subject to substantial penalties, which would decrease our profitability.

We must obtain governmental permits and approvals for drilling operations, which can be a costly and time consuming process and result in restrictions on our operations.

Regulatory authorities exercise considerable discretion in the timing and scope of permit issuance. Requirements imposed by these authorities may be costly and time consuming and may result in delays in the commencement or continuation of our exploration or production operations. For example, we are often required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that proposed exploration for or production of gas may have on the environment. Further, the public may comment on and otherwise engage in the permitting process, including through intervention in the courts. Accordingly, the permits we need may not be issued, or if issued, may not be issued in a timely fashion, or may involve requirements that restrict our ability to conduct our operations or to do so profitably.

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We have limited protection for our technology and depend on technology owned by others.

We use operating practices that management believes are of significant value in developing CBM resources. In most cases, patent or other intellectual property protection is unavailable for this technology. Our use of independent contractors in most aspects of our drilling and some completion operations makes the protection of such technology more difficult. Moreover, we rely on the technological expertise of the independent contractors that we retain for our operations. We have no long-term agreements with these contractors, and thus we cannot be sure that we will continue to have access to this expertise.

We may incur additional costs to produce gas because our confirmation of title for gas rights for some of our properties may be inadequate or incomplete.

We generally obtain title opinions on significant properties that we drill or acquire. However, we cannot be sure that we will not suffer a monetary loss from title defects or failure. In addition, the steps needed to perfect our ownership varies from state to state and some states permit us to produce the gas without perfected ownership under forced pooling arrangements while other states do not permit this. As a result, we may have to incur title costs and pay royalties to produce gas on acreage that we control and these costs may be material and vary depending upon the state in which we operate.

The unavailability or high cost of drilling rigs, equipment, supplies, personnel, and oilfield services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

Our industry is cyclical, and from time to time there is a shortage of drilling rigs, equipment, supplies or qualified personnel. During these periods, the costs and delivery times of rigs, equipment, and supplies are substantially greater. As a result of historically strong prices of gas, the demand for oilfield services has risen, and the costs of these services are increasing. If the unavailability or high cost of drilling rigs, equipment, supplies, or qualified personnel were particularly severe in the areas where we operate, we could be materially and adversely affected.

Hedging transactions may limit our potential gains.

In order to manage our exposure to price risks in the marketing of our natural gas production, we have entered into natural gas price hedging arrangements with respect to a portion of our expected production. We will most likely enter into additional hedging transactions in the future. While intended to reduce the effects of volatile natural gas prices, such transactions may limit our potential gains and increase our potential losses if natural gas prices were to rise substantially over the price established by the hedge. For example, as a consequence of increases in natural gas prices during the year ended December 31, 2005, we realized pre-tax losses on our hedging activities of approximately $7.5 million. At December 31, 2005, our unrealized pre-tax losses on our outstanding hedges were approximately $12 million. Based upon the hedges we had in place at December 31, 2005, hypothetical 10% and 25% increases in natural gas prices would have increased our pre-tax loss by approximately $4.9 million and $12.9 million, respectively. In addition, such transactions may expose us to the risk of loss in certain circumstances, including instances in which:

- our production is less than expected; or
- the counterparties to our hedging agreements fail to perform under the contracts.

We do not insure against all potential operating risks. We may incur substantial losses and be subject to substantial liability claims as a result of our natural gas operations.

We maintain insurance for some, but not all, of the potential risks and liabilities associated with our business. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive

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relative to the risks presented. As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. As a result, we may not be able to renew our existing insurance policies or procure other desirable insurance on commercially reasonable terms, if at all. Although we maintain insurance at levels we believe are appropriate and consistent with industry practice, we are not fully insured against all risks, including drilling and completion risks that are generally not recoverable from third parties or insurance. In addition, pollution and environmental risks generally are not fully insurable. Losses and liabilities from uninsured and underinsured events and delay in the payment of insurance proceeds could have a material adverse effect on our financial condition and results of operations.

Risks Relating to Our Common Stock

One existing stockholder holds a substantial interest in our company, and insiders own a significant amount of our common stock, which could limit your ability to influence the outcome of stockholder votes, and the interests of this stockholder and these insiders could differ from those of our other stockholders.

A representative of Yorktown Energy Partners IV, L.P. (Yorktown) serves on our board of directors, and Yorktown presently owns approximately 49.9% of our outstanding common stock. In addition, our officers and their affiliates beneficially own or control approximately 13.6% of our outstanding common stock. Contemporaneously with this offering, we are conducting an initial public offering of shares of our common stock. Following the closing of our initial public offering, Yorktown will own or control approximately % of our outstanding common stock and our officers and their affiliates will beneficially own or control % of our outstanding common stock. Yorktown and our executive officers and directors have, and can be expected to continue to have, a significant voice in our affairs and in the outcome of stockholder voting. Under Delaware law and our certificate of incorporation, matters requiring a stockholder to vote, including the election of directors, the adoption of an amendment to our certificate of incorporation, and the approval of mergers and other significant corporate transactions require the affirmative vote of the holders of a majority of the outstanding shares or, in the case of the election of directors, a plurality of the votes cast. As a consequence, the effect of this level of share ownership by Yorktown and our officers and directors may permit them to approve certain matters by written consent and may delay or prevent a change of control of us or otherwise protect your investment.

There has been no public market for our common stock, and our stock price may fluctuate significantly.

There is currently no public market for our common stock, and an active trading market may not develop or be sustained after the sale of all of the shares covered by this prospectus. The market price of our common stock could fluctuate significantly as a result of:

our operating and financial performance and prospects;

quarterly variations in the rate of growth of our financial indicators, such as net income per share, net income and revenues;

changes in revenue or earnings estimates or publication of research reports by analysts about us or the exploration and production industry;

liquidity and registering our common stock for public resale;

actual or unanticipated variations in our reserve estimates and quarterly operating results;

changes in oil and gas prices;

speculation in the press or investment community;

sales of our common stock by our stockholders;

increases in our cost of capital;

changes in applicable laws or regulations, court rulings and enforcement and legal actions;

changes in market valuations of similar companies;

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- adverse market reaction to any increased indebtedness we incur in the future;
- additions or departures of key management personnel;
- actions by our stockholders;
- general market and economic conditions, including the occurrence of events or trends affecting the price of natural gas; and
- domestic and international economic, legal, and regulatory factors unrelated to our performance.

If a trading market develops for our common stock, stock markets in general experience volatility that often is unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of our common stock.

We may not be accepted for listing or inclusion on a national securities exchange.

In connection with our filing of this registration statement, we have agreed to use commercially reasonable efforts to satisfy the criteria for inclusion of (if we meet the criteria for listing on such market) our common stock on The Nasdaq National Market as soon as practicable (including seeking to cure in our listing and inclusion application any deficiencies cited by such market), and thereafter maintain the listing on The Nasdaq National Market. The Nasdaq National Market has initial listing criteria, including criteria related to minimum bid price, public float, market makers, minimum number of round lot holders, and board independence requirements, that we can give no assurance that we will meet. We currently do not satisfy the minimum round lot holder requirements of The Nasdaq National Market. Our inability to list or include our common stock on The Nasdaq National Market could affect the ability of stockholders to sell their shares of common stock and consequently adversely affect the value of such shares. In addition, we would have more difficulty attracting the attention of market analysts to cover us in their research.

If our common stock is approved for inclusion on The Nasdaq National Market, we will have no prior trading history, and thus there is no way to determine the prices or volumes at which our common stock will trade. We can give no assurances as to the development of liquidity or any trading market for our common stock. Holders of shares of our common stock may not be able to resell their shares at or near their original acquisition price, or at any price.

We do not intend to pay, and are prohibited from paying, any dividends on our common stock.

We anticipate that we will retain all future earnings and other cash resources for the future operation and development of our business. Accordingly, we do not intend to declare or pay any cash dividends on our common stock in the foreseeable future. Payment of any future dividends will be at the discretion of our board of directors after taking into account many factors, including our operating results, financial condition, current and anticipated cash needs and plans for expansion. In addition, the declaration and payment of any dividends on our common stock is prohibited by the terms of our credit facility so long as it is in effect. The credit facility terminates in January 2011; however, prior to that time we may enter into a new credit facility or other contractual arrangement that further restricts our ability to pay dividends.

You may experience dilution of your ownership interests due to the future issuance of shares of our common stock, which could have an adverse effect on our stock price.

We may in the future issue our previously authorized and unissued securities, resulting in the dilution of the ownership interests of our present stockholders and purchasers of common stock offered hereby. Our authorized capital stock consists of 125 million shares of common stock and 10 million shares of preferred stock with such designations, preferences, and rights as may determined by our board of directors. As of March 31, 2006,

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32,614,021 shares of common stock and no shares of preferred stock were outstanding. As of March 31, 2006, we have reserved 4,400,000 shares for future issuance to employees as restricted stock or stock option awards pursuant to our stock option plans, of which options to purchase 2,172,552 shares have already been granted, 1,770,990 of which remain outstanding and 2,227,448 shares remain available for future grants. The potential issuance of such additional shares of common stock may create downward pressure on the trading price of our common stock. We may also issue additional shares of our common stock or other securities that are convertible into or exercisable for common stock in connection with the hiring of personnel, future acquisitions, future private placements of our securities for capital raising purposes, or for other business purposes. Future sales of substantial amounts of our common stock, or the perception that sales could occur, could have a material adverse effect on the price of our common stock.

We will incur increased costs as a result of being a public company.

As a public company, we will incur significant legal, accounting and other expenses that we did not incur as a private company. The U.S. Sarbanes-Oxley Act of 2002 and related rules of the U.S. Securities and Exchange Commission, or SEC, and The Nasdaq National Market regulate corporate governance practices of public companies. We expect that compliance with these public company requirements will increase our costs and make some activities more time consuming. For example, we have created new board committees, and we will adopt new internal controls and disclosure controls and procedures. In addition, we will incur additional expenses associated with our SEC reporting requirements. A number of those requirements will require us to carry out activities we have not conducted previously. For example, under Section 404 of the Sarbanes-Oxley Act, for our annual report on Form 10-K for 2007, we will need to document and test our internal control procedures, our management will need to assess and report on our internal control over financial reporting and our independent accountants will need to issue an opinion on that assessment and the effectiveness of those controls. Furthermore, if we identify any issues in complying with those requirements (for example, if we or our independent auditors identified a material weakness or significant deficiency in our internal control over financial reporting), we could incur additional costs rectifying those issues, and the existence of those issues could adversely affect us, our reputation or investor perceptions of us. We also expect that it could be difficult and will be significantly more expensive to obtain directors and officers liability insurance, and we may be required to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage. As a result, it may be more difficult for us to attract and retain qualified persons to serve on our board of directors or as executive officers. Advocacy efforts by shareholders and third parties may also prompt even more changes in governance and reporting requirements. We cannot predict or estimate the amount of additional costs we may incur or the timing of such costs.

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CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

Various statements in this prospectus, including those that express a belief, expectation, or intention, as well as those that are not statements of historical fact, are forward-looking statements. The forward-looking statements may include projections and estimates concerning the timing and success of specific projects and our future reserves, production, revenues, income, and capital spending. When we use the words believe, intend, expect, may, should, anticipate, could, estimate, plan, predict, project, or their negatives, other similar expressions, or the statem those words are usually forward-looking statements.

The forward-looking statements contained in this prospectus are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management s assumptions about future events may prove to be inaccurate. Management cautions all readers that the forward-looking statements contained in this prospectus are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to the factors listed in the Risk Factors section and elsewhere in this prospectus. All forward-looking statements speak only as of the date of this prospectus. We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us, or persons acting on our behalf. The risks, contingencies and uncertainties relate to, among other matters, the following:

- our business strategy;
- our financial position;
- our cash flow and liquidity;
- declines in the prices we receive for our gas affecting our operating results and cash flows;
- uncertainties in estimating our gas reserves;
- replacing our gas reserves;
- uncertainties in exploring for and producing gas;
- our inability to obtain additional financing necessary in order to fund our operations, capital expenditures, and to meet our other obligations;
- availability of drilling and production equipment and field service providers;

disruptions, capacity constraints in, or other limitations on the pipeline systems which deliver our gas;

competition in the gas industry;

our inability to retain and attract key personnel;

our joint venture arrangements;

the effects of government regulation and permitting and other legal requirements;

costs associated with perfecting title for gas rights in some of our properties;

our need to use unproven technologies to extract coalbed methane in some properties; and

other factors discussed under Risk Factors.

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USE OF PROCEEDS

We will not receive any of the proceeds from the sale of the shares of common stock offered by this prospectus. Any proceeds from the sale of the shares pursuant to this prospectus will be received by the selling stockholders.

DIVIDEND POLICY

We do not expect to declare or pay any cash or other dividends in the foreseeable future on our common stock, as we intend to reinvest cash flow generated by operations in our business. Our credit facility currently prohibits us from paying cash dividends on our common stock so long as it is in effect. Our credit facility terminates in January 2011; however, prior to that time we may enter into other credit agreements or borrowing arrangements that restrict our ability to declare or pay cash dividends on our common stock. Our board of directors has the authority to issue preferred stock and to fix dividend rights that may have preference to our common stock.

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CAPITALIZATION

The following table presents our capitalization as of December 31, 2005, on:

- a historical basis;

- a pro forma basis to give effect to our private placement of 2,317,023 shares of our common stock, the issuance of 192,020 shares of common stock upon the exercise of stock options, our four-for-one common stock split, and the repayment of certain stockholder loans during the first quarter of 2006; and

- a pro forma as adjusted basis to give effect to the sale of shares in our initial public offering and the application of the net proceeds from our initial public offering.

You should read this table in conjunction with our consolidated financial statements included in this prospectus.

	December 31, 2005		
	Historical	Pro Forma	Pro Forma As Adjusted
		(In thousands)	
Cash and cash equivalents(1)	$ 616	$	$
Long-term debt(1)	$ 99,926	$ 54,938	$
Stockholders equity:			
Common stock, $0.001 par value, 125,000,000 shares authorized; and 37,614,021 shares issued and outstanding, pro forma and shares issued and outstanding, pro forma as adjusted(2)	$ 30	$ 32	$
Preferred stock, $0.001 par value, 10,000,000 shares authorized, none issued(2)			
Additional paid-in capital(3)	106,409	134,035	
Accumulated other comprehensive income	56	56	
Retained earnings	6,444	6,444	
Notes receivable(1)	(17,517)	(407)	
Total stockholders equity	95,422	140,160	
Total capitalization	$ 195,348	$ 195,098	$

(1) Long-term debt decreased by $27,162,000 from the sale of 2,317,023 shares of common stock in our private placement during the first quarter of 2006; by $17,360,000 from the proceeds received from the repayment of loans with interest by selling stockholders (including $250,000 in notes receivable included in other assets); by $466,279 in proceeds from the exercise of stock options in January 2006; and by $ from the sale of shares of common

stock in our initial public offering.

(2) Our authorized capital stock increased in January 2006 from 10,000,000 shares of common stock to 135,000,000 shares of capital stock, consisting of 125,000,000 shares of common stock and 10,000,000 shares of preferred stock.

(3) Our additional paid-in capital increased by approximately $ from the sale of 2,317,023 shares of common stock in our private placement during the first quarter of 2006; from the exercise of stock options in January 2006; and from the sale of shares of common stock in our initial public offering.

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SELECTED HISTORICAL CONSOLIDATED FINANCIAL AND OPERATING DATA

The following table shows our summary historical consolidated financial and operating data as of and for each of the five years ended December 31, 2005. The summary historical consolidated financial and operating data for the three years ended December 31, 2005 are derived from our audited financial statements included herein. The summary historical consolidated financial and operating data for the two years ended December 31, 2002 was derived from our audited financial statements which are not included herein. You should read the following data in conjunction with Managements Discussion and Analysis of Results of Operations and Financial Condition and our consolidated financial statements and related notes included elsewhere in this prospectus where there is additional disclosure regarding the information in the following table. Our historical results are not necessarily indicative of the results that may be expected in future periods.

	Year Ended December 31,				
	2005	2004	2003	2002	2001
	(In thousands, unless otherwise indicated)				
STATEMENT OF OPERATIONS AND COMPREHENSIVE INCOME DATA:					
REVENUES					
Gas sales	$ 41,604	$ 19,522	$ 11,700	$ 6,731	$ 11,850
Operating fees and other	376	1,402	349	277	205
Total revenues	41,980	20,924	12,049	7,008	12,055
EXPENSES					
Lease operating expenses	8,687	5,092	1,640	590	542
Compression and transportation expenses	3,332	1,951	993	654	681
Production taxes	914	473	414	285	560
Depreciation, depletion and amortization	4,867	2,691	2,120	2,151	3,167
Research and development	609	279	432	168	
General and administrative	3,208	2,513	1,370	1,598	1,206
Impairment of other equipment and other non-current assets			8	108	
Realized losses on derivative contracts	7,473	815	44		
Unrealized losses (gains) from the change in market value of open derivative contracts	12,059	(542)	102		
Total operating expenses	41,149	13,272	7,123	5,554	6,156
Income from operations	831	7,652	4,926	1,454	5,899
Interest income	77	70	95	119	291
Interest expense (net of amounts capitalized)	(3,895)	(986)	(232)	(186)	(151)
Other expenses	(21)	(4)	(7)	(7)	(3)
Total other income (expense)	(3,839)	(920)	(144)	(74)	137
Income (loss) before income taxes, minority interest, and cumulative effect of change in accounting principle, net of income tax	(3,008)	6,732	4,782	1,380	6,036
Income tax provision (benefit)	(993)	2,312	1,651	639	1,152
Net income (loss) before minority interest and cumulative effect of change in accounting principle, net of income tax	(2,015)	4,420	3,131	741	4,884
Minority interest	(442)	584	571	138	958

Net income (loss) before cumulative effect of change in accounting principle, net of income tax	(1,573)	3,836	2,560	603	3,926
Cumulative effect of change in accounting principle, net of income tax			19		
Net income (loss)	(1,573)	3,836	2,541	603	3,926
Other comprehensive income					
Foreign currency translation adjustment, net of income taxes of $0	54	2			
Comprehensive income (loss)	$ (1,519)	$ 3,838	$ 2,541	$ 603	$ 3,926

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SELECTED HISTORICAL CONSOLIDATED FINANCIAL AND OPERATING DATA (continued):

	Year Ended December 31,				
	2005	2004	2003	2002	2001
	(In thousands unless otherwise indicated)				
Net income (loss) per common share:					
Basic	$ (0.06)	$ 0.17	$ 0.20	$ 0.08	$ 0.49
Diluted	$ (0.06)	$ 0.17	$ 0.20	$ 0.08	$ 0.49
BALANCE SHEET DATA (at period end):					
Working capital (deficit)	$ (7,368)	$ (1,251)	$ 5,133	$ 3,940	$ 6,268
Total assets	$ 247,909	$ 142,090	$ 81,505	$ 42,261	$ 33,240
Long-term debt	$ 99,926	$ 51,513	$ 10,102	$ 6,665	$ 1,242
Stockholders equity	$ 95,422	$ 65,692	$ 52,754	$ 22,912	$ 22,310
OTHER DATA:					
Net cash provided by operating activities	$ 12,433	$ 10,580	$ 10,801	$ 4,603	$ 8,669
Net cash used in investing activities	$ (59,661)	$ (66,193)	$ (36,341)	$ (12,773)	$ (5,232)
Net cash provided by (used in) financing activities	$ 44,906	$ 50,192	$ 30,534	$ 5,372	$ (2,127)
Capital expenditures	$ 59,817	$ 86,189	$ 36,069	$ 12,770	$ 5,117
Net sales volume (Bcf)	4.6	3.2	2.5	2.1	2.5
Average natural gas sales price ($ per Mcf)	$ 9.06	$ 6.12	$ 4.71	$ 3.16	$ 4.73
Average natural gas sales price ($ per Mcf) realized(1)	$ 7.43	$ 5.87	$ 4.69	$ 3.16	$ 4.73
Total production expenses ($ per Mcf)	$ 2.81	$ 2.36	$ 1.23	$ 0.72	$ 0.71
Estimated proved reserves (Bcf)(2)	262.5	209.9	103.9	35.5	16.7
PV-10 ($ millions)(2)(3)	$ 880.2	$ 481.8	$ 236.9	$ 64.4	$ 19.2
Standardized measure of discounted future net cash flows ($ millions)	$ 632.7	$ 349.8	$ 172.5	$ 45.4	$ 14.0
EBITDA ($millions)(3)	$ 6.1	$ 9.8	$ 6.5	$ 3.5	$ 8.1

(1) Average realized price includes the effects of realized losses on derivative contracts.

(2) Based on the reserve reports prepared by DeGolyer and MacNaughton, independent petroleum engineers, at each period end. Natural gas prices are volatile and may fluctuate widely affecting significantly the calculation of estimated net cash flows. Refer to Risk Factors for a more complete discussion.

(3) See the Reconciliation of Non-GAAP Financial Measures below for additional information.

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Reconciliation of Non-GAAP Financial Measures

The following table shows our reconciliation of our PV-10 to our standardized measure of discounted future net cash flows (the most directly comparable measure calculated and presented in accordance with GAAP). PV-10 is our estimate of the present value of future net revenues from estimated proved natural gas reserves after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates of federal income taxes. The estimated future net revenues are discounted at an annual rate of 10% to determine their present value. We believe PV-10 to be an important measure for evaluating the relative significance of our CBM gas properties and that the presentation of the non-GAAP financial measure of PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and gas companies. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable for evaluating our company. We believe that most other companies in the oil and gas industry calculate PV-10 on the same basis. PV-10 should not be considered as an alternative to the standardized measure of discounted future net cash flows as computed under GAAP.

	As of December 31,				
	2005	2004	2003	2002	2001
	(In thousands)				
Future cash inflows	$ 2,536,279	$ 1,302,830	$ 599,501	$ 163,986	$ 45,679
Less: Future production costs	463,416	290,425	125,765	48,771	14,030
Less: Future development costs	76,297	38,242	23,832	4,676	1,140
Future net cash flows	1,996,566	974,163	449,904	110,539	30,509
Less: 10% discount factor	1,116,413	(492,339)	(213,018)	(46,095)	(11,310)
PV-10	$ 880,153	481,824	236,886	64,444	19,199
Less: Undiscounted income taxes	(579,689)	(274,975)	(125,858)	(32,101)	(8,196)
Plus: 10% discount factor	332,201	142,906	61,520	13,084	2,969
Discounted income taxes	(247,488)	(132,069)	(64,338)	(19,017)	(5,227)
Standardized measure of discounted future net cash flows	$ 632,665	$ 349,755	$ 172,548	$ 45,427	$ 13,972

The following table reconciles our net income (loss) to EBITDA. EBITDA is defined as earnings (loss) before deducting net interest expense, income taxes and depreciation, depletion and amortization. Although EBITDA is not a measure of performance calculated in accordance with generally accepted accounting principles (GAAP), management believes that it is useful to an investor in evaluating our company because it is a widely used measure to evaluate a company s operating performance.

	Year Ended December 31,				
	2005	2004	2003	2002	2001

	(In thousands)				
Net income (loss)	$ (1,573)	$ 3,836	$ 2,541	$ 603	$ 3,926
Add: Interest expense	3,895	986	232	186	151
Less: Interest income	(77)	(70)	(94)	(119)	(291)
Add (Deduct): Provision for income taxes	(993)	2,312	1,651	639	1,152
Add: Depreciation, depletion and amortization	4,867	2,691	2,120	2,151	3,167
EBITDA	$ 6,119	$ 9,755	$ 6,450	$ 3,460	$ 8,105

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MANAGEMENT S DISCUSSION AND ANALYSIS OF

RESULTS OF OPERATIONS AND FINANCIAL CONDITION

The following is a discussion and analysis of our financial condition and results of operations and should be read in conjunction with our consolidated financial statements and related notes included elsewhere in this prospectus.

Overview

We are an independent natural gas producer involved in the exploration, development, and production of natural gas from coal seams (coalbed methane or CBM). Our principal operations and producing properties are located in the Cahaba Basin in Alabama and the Appalachian Basin in West Virginia and Virginia. We control a total of approximately 255,000 net acres of coalbed methane development rights, primarily in Alabama, West Virginia, Virginia, Louisiana, Colorado, and British Columbia.

We have been very active in North America for over twenty years as an operator of CBM fields owned by us, as a contract operator for CBM fields in which we owned an interest, and as a consultant or contract operator for CBM fields owned by other companies. Over the last five years, we have focused on expanding the number of projects that we own and operate. This focus resulted in the initial development of our two primary producing properties, the Gurnee field in the Cahaba Basin and the Pond Creek field in the Appalachian Basin. Additionally, we own and operate several active exploration projects. This change in focus of our operations has also resulted in a significant increase in our business, ranging from capital expenditures to headcount.

Effective April 30, 2004, we acquired the working interests of our 50% partner in the Appalachian Basin, including a 50% working interest in the Pond Creek field, for cash consideration of $27 million and a contingent payment of up to $3 million, which we expect to pay in full in 2008 (the Pond Creek Acquisition). In the acquisition we acquired approximately 31.8 Bcf of estimated proved reserves at a price of $0.84 per Mcf.

Effective June 7, 2004, we sold our 10% working interest in the White Oak Creek field in the Black Warrior Basin for $21 million (the White Oak Creek Sale). We sold approximately 8.4 Bcf of our estimated proved reserves at a price of $2.50 per Mcf while retaining an approximate 3% overriding royalty interest in the field. This overriding royalty interest is presently subject to a dispute. The trial court has ruled in our favor; however, the case is currently under appeal. See Business Legal Proceedings for a further discussion of this lawsuit. Prior to 2003 and the start-up of the Pond Creek field, our working and overriding interests in the White Oak Creek field were our primary sources of production, revenue, and cash flow.

On January 30, 2006, we sold 2,067,023 shares of common stock in a private placement to qualified institutional buyers pursuant to Rule 144A under the Securities Act. In connection with this offering, on February 7, 2006, we sold an additional 250,000 shares of our common stock to qualified institutional buyers under Rule 144A under the Securities Act pursuant to the initial purchaser s option to purchase additional shares.

The net proceeds from our private placement of common stock during the first quarter of 2006 of approximately $27 million and the receipt of approximately $17.5 million from the repayment of certain stockholder loans and from the exercise of stock options by certain of the selling stockholders were used to reduce outstanding borrowings under our bank credit facility and for general corporate purposes.

Unlike conventional natural gas production operations, in the early stages of a CBM project, production of water is generally comparatively higher and production of gas lower. Typically, gas production from CBM projects gradually increases over time as pressure is lowered due to extraction of water and as additional wells are drilled. As water extraction continues and the maximum number of wells drilled on the project acreage is reached, production peaks and stabilizes for a period and ultimately begins to decline. The length of time that it takes to dewater a particular reservoir before it produces gas and the method to dispose of the water varies.

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Generally, gas and water are produced simultaneously and the dewatering occurs over time. In other situations, the well will produce only water for a period of time before meaningful gas production begins. At Pond Creek the wells usually produce gas and water simultaneously, while at Gurnee some wells produce only water for 1 to 6 months before meaningful gas production begins. At both projects, certain wells produce only water which helps to dewater the entire reservoir.

The methods used to dispose of the produced water are different for Pond Creek and Gurnee. The produced water at Pond Creek flows from gathering lines into holding tanks where it is trucked and injected into a water disposal well. At Gurnee the produced water flows from gathering lines, is treated and transported by pipeline to a location where it is treated a second time and discharged. The construction of water disposal facilities usually requires significant capital investment in the early phase of the project. As a consequence of these unique CBM characteristics, we may be required to expend substantial capital to develop a CBM field many months before meaningful production and resulting cash flows are realized.

A significant portion of our operating expenses are fixed, generally driven by the number of producing wells, the disposal of produced water, and the cost and maintenance of infrastructure. Over time, as gas production increases and produced water declines, lease operating expenses per unit of production are generally lower. As an example, the per Mcf lease operating expense at the White Oak Creek field, a mature CBM project that reached peak gas production in 2001, was $0.60 for the first five months of 2004 (through the date of the White Oak Creek sale). Conversely, our primary producing properties, Pond Creek and Gurnee, are at much earlier stages in their lifecycles with development operations beginning on June 30, 2002 and December 31, 2003, respectively, and gas sales commencing in February 2003 and January 2004, respectively. The lease operating expense per Mcf for these fields for the year ended December 31, 2005 was $1.43 and $3.55, respectively. The per unit operating expenses for these properties are high relative to White Oak Creek due to their earlier stages of development, but are expected to decline as gas production increases. For the year ended December 31, 2005, sales volumes from the Gurnee and Pond Creek projects accounted for approximately 90% of our total sales volumes. As a result of the concentration of sales volumes in these two projects, our gas revenues, profitability, and cash flows will be primarily dependent on the performance of these projects.

To reduce our exposure to fluctuations in natural gas prices, which have exhibited a high degree of volatility over the past several years, we periodically enter into derivative commodity instruments. Our policy is to enter into hedging transactions which increase our statistical probability of achieving our targeted level of cash flows.

Critical Accounting Policies

Our discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements that have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make assumptions and estimates that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the dates of the financial statements and the reported amounts of revenues and expenses during the reporting periods. We base our estimates on historical experiences and various other assumptions that we believe are reasonable; however, actual results may differ. Our significant accounting policies are described in Note 2 to our consolidated financial statements included elsewhere in this prospectus. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our financial statements:

Reserves. Our most significant financial estimates are based on estimates of proved gas reserves. Proved gas reserves represent estimated quantities of gas that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions existing at the time the estimates were made. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future revenues, rates of production, and timing of development expenditures, including many factors beyond our control. The estimation process relies on assumptions and

interpretations of available geologic, geophysical, engineering, and production data and, the accuracy of reserve estimates is a function of the quality and quantity of available data, engineering and geologic interpretation, and

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judgment. In addition, as a result of changing market conditions, commodity prices and future development costs will change from year to year, causing estimates of proved reserves to also change. Estimates of proved reserves are key components of our most significant financial estimates involving our unevaluated properties, our rate for recording depreciation, depletion and amortization and our full cost ceiling limitation. Our reserves are fully engineered on an annual basis by DeGolyer & MacNaughton, our independent petroleum engineers.

Gas Properties. The method of accounting for gas properties determines what costs are capitalized and how these costs are ultimately matched with revenues and expenses. We use the full cost method of accounting for gas properties. Under this method, all direct costs and certain indirect costs associated with the acquisition, exploration, and development of our gas properties are capitalized and segregated into U.S. and Canadian cost centers.

Gas properties are depleted using the unit-of-production method. The depletion expense is significantly affected by the unamortized historical and future development costs and the estimated proved gas reserves. Estimation of proved gas reserves relies on professional judgment and use of factors that cannot be precisely determined. Holding all other factors constant, if proved gas reserves were revised upward or downward, earnings would increase or decrease, respectively. Subsequent proved reserve estimates materially different from those reported would change the depletion expense recognized during the future reporting period. No gains or losses are recognized upon the sale or disposition of gas properties unless the sale or disposition represents a significant quantity of gas reserves, which would have a significant impact on the depreciation, depletion and amortization rate.

Under full cost accounting rules, total capitalized costs are limited to a ceiling equal to the present value of future net revenues, discounted at 10% per annum, plus the lower of cost or fair value of unevaluated properties less income tax effects (the ceiling limitation). We perform a quarterly ceiling test to evaluate whether the net book value of our full cost pool exceeds the ceiling limitation. The ceiling test is imposed separately for our U.S. and Canadian cost centers. If capitalized costs (net of accumulated depreciation, depletion and amortization) less related deferred taxes are greater than the discounted future net revenues or ceiling limitation, a write-down or impairment of the full cost pool is required. A write-down of the carrying value of the full cost pool is a non-cash charge that reduces earnings and impacts stockholders equity in the period of occurrence and typically results in lower depreciation, depletion and amortization expense in future periods. Once incurred, a write-down is not reversible at a later date. The risk that we will be required to write down the carrying value of our gas properties increases when gas prices are depressed, even if low prices are temporary. In addition, a write-down may occur if estimates of proved gas reserves are substantially reduced or estimates of future development costs increase significantly.

The ceiling test is calculated using natural gas prices in effect as of the balance sheet date and adjusted for basis or location differential, held constant over the life of the reserves. In addition, subsequent to the adoption of SFAS 143, Accounting for Asset Retirement Obligations, the future cash outflows associated with settling asset retirement obligations were not included in the computation of the discounted present value of future net revenues for the purposes of the ceiling test calculation.

Unevaluated Properties. The costs directly associated with unevaluated properties and properties under development are not initially included in the amortization base and relate to unproved leasehold acreage, seismic data, wells and production facilities in progress and wells pending determination together with interest costs capitalized for these projects. Unevaluated leasehold costs are transferred to the amortization base once determination has been made or upon expiration of a lease. Geological and geophysical costs associated with a specific unevaluated property are transferred to the amortization base with the associated leasehold costs on a specific project basis. Costs associated with wells in progress and wells pending determination are transferred to the amortization base once a determination is made whether or not proved reserves can be assigned to the property. All items included in our unevaluated property balance are assessed on a quarterly basis for possible impairment or reduction in value. Any impairments to unevaluated properties are transferred to the amortization base.

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Future Abandonment Costs.

We have significant legal obligations to plug, abandon and dismantle existing wells and facilities that we have acquired, constructed, or developed. Liabilities for asset retirement obligations are recorded at fair value in the period incurred. Upon initial recognition of the asset retirement liability, the asset retirement cost is capitalized by increasing the carrying amount of the long-lived asset by the same amount as the liability. Asset retirement costs included in the carrying amount of the related asset are subsequently allocated to expense as part of our depletion calculation. Additionally, increases in the discounted asset retirement liability resulting from the passage of time are recorded as lease operating expense.

Estimating the future asset retirement liability requires us to make estimates and judgments regarding timing, existence of a liability, as well as what constitutes adequate restoration. We use the present value of estimated cash flows related to our asset retirement obligations to determine the fair value. Present value calculations inherently incorporate numerous assumptions and judgments. These include the ultimate retirement and restoration costs, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing asset retirement liability, a corresponding adjustment will be made to the carrying cost of the related asset.

Price Risk Management Activities. We account for our price risk management activities under the provisions of SFAS No. 133 *Accounting for Derivative Instruments and Hedging Activities*, as amended. We record the fair value of our derivative instruments on our balance sheet as either an asset or liability. The statement requires that changes in the derivative s fair value be recognized currently in the income statement unless specific hedge accounting criteria are met. We have elected not to designate any of our current price risk management activities as accounting hedges, and accordingly, accounted for them using the mark-to-market accounting method. Under this accounting method, the changes in the market value of outstanding financial instruments are recognized as gains or losses which are included in operating expenses in the period of change. Our estimates of fair value are determined by obtaining independent market quotes from our counterparties. The fair values determined by the counterparties are based, in part, on estimates and judgments.

Revenue Recognition. We derive revenue primarily from the sale of produced natural gas. We use the sales method of accounting for the recognition of gas revenue. Because there is a ready market for natural gas, we sell our natural gas shortly after production at various pipeline receipt points at which time title and risk of loss transfers to the buyer. Revenue is recorded when title is transferred based on our net revenue interests. Gas sold in production operations is not significantly different from our share of production based on our interest in the properties.

Settlements of gas sales occur after the month in which the gas was produced. We estimate and accrue for the value of these sales using information available at the time financial statements are generated. Differences are reflected in the accounting period that payments are received from the purchaser.

Income Taxes. We record our income taxes using an asset and liability approach in accordance with the provisions of the Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes*. This results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax bases of assets and liabilities using enacted tax rates at the end of the period. Under SFAS No. 109, the effect of a change in tax rates of deferred tax assets and liabilities is recognized in the year of the enacted change. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

Estimating the amount of valuation allowance is dependent on estimates of future taxable income, alternative minimum tax income, and changes in stockholder ownership that could trigger limits on use of net

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operating losses under Internal Revenue Code Section 382. We have a significant deferred tax asset associated with net operating loss carryforwards (NOLs). It is more likely than not that we will use these NOLs to offset current tax liabilities in future years.

Future Charges

Public Company Expenses

We believe that our general and administrative expenses will increase in connection with the filing of this registration statement. This increase will consist of legal and accounting fees and additional expenses associated with compliance with the Sarbanes-Oxley Act of 2002 and other regulations. We anticipate that our ongoing general and administrative expenses will also increase as a result of being a publicly traded company. This increase will be due primarily to the cost of accounting support services, filing annual and quarterly reports with the SEC, investor relations, directors fees, directors and officers insurance, and registrar and transfer agent fees. As a result, we believe that our general and administrative expenses for 2006 will increase significantly. Our consolidated financial statements following the completion of this offering will reflect the impact of these increased expenses and affect the comparability of our financial statements with periods prior to the completion of this offering.

Stock Compensation

Effective January 1, 2006, we adopted the fair value recognition provisions of Statement of Financial Accounting Standards (SFAS) No. 123R, Share-Based Payment (SFAS 123R), using the prospective transition method. Due to the adoption of SFAS 123R, we expect our compensation expense related to the granting of share-based awards subsequent to adoption to be higher than in prior periods. For awards outstanding as of January 1, 2006, we will continue using the accounting principles originally applied to those awards before adoption. Therefore, no equity compensation cost will be recognized on these awards in the future unless such awards are modified, repurchased or cancelled.

Stock-based employee compensation is accounted for under the intrinsic value method of Accounting Principles Bulletin No. 25 Accounting for Stock Issued to Employees. For the years ended December 31, 2005, 2004, and 2003, the exercise price of the options granted was equal to the estimated fair value of our common stock at grant date, and therefore, no compensation costs have been recognized under stock option plans. We used the income method on a semi-annual basis to estimate the market value of our common stock at grant date. As allowed by SFAS No. 123, Accounting for Stock-Based Compensation issued in 1995, we have continued to apply APB Opinion No. 25 for the purpose of determining net income and to present pro forma disclosures required by SFAS No. 123. The table below shows pro forma amounts for what net income would have been if compensation cost had been determined under fair value methods at grant date for stock options granted for the years ended December 31, 2005, 2004 and 2003.

	Years Ended December 31,		
	2005	**2004**	**2003**
Net income (loss) as reported	$ (1,573,281)	$ 3,835,781	$ 2,541,418

Less: Total stock-based employee compensation expense determined			
under fair value based methods for all grants, net of related tax effects	61,178	63,196	87,809
Pro forma	$ (1,634,459)	$ 3,772,585	$ 2,453,609

The effects of applying SFAS 123 in this pro forma disclosure may not be representative of future amounts. See Note 9 to our consolidated financial statements included elsewhere in this prospectus for additional detail on stock options. The fair value of each option grant was based on the minimum value method with the following

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assumptions used for grants for the years ended December 31, 2005, 2004 and 2003: (a) dividend yield of 0%, (b) expected volatility of 0%, (c) risk-free interest rate of 3.4% in 2005, 2.6% in 2004, and 2.5% in 2003, and (d) an expected life of three years for 2005 and 2004, and four years for 2003.

Given the lack of an active public market for our common stock, our compensation committee established the fair value of our common stock for incentive stock option awards based on the recommendation of senior management using the best information available on the date of grant. We used the income method except when there was other, more conclusive evidence of fair value, such as a recent arms-length event or transaction involving the acquisition or exchange of our common stock. Determining the fair value of our common stock required making complex and subjective judgments regarding a number of variables and data points. We used the income method in lieu of other acceptable methods because the income method applies cash flow modeling and assumptions similar to those used in determining the PV-10 of our proved gas reserves. We did not obtain a contemporaneous valuation by an unrelated valuation specialist for the options granted during 2005 because we believed that both our senior management and the management of our majority stockholder had adequate expertise and experience in valuing gas properties and entities with gas exploration, production, and development activities.

Information on stock option grants during the year ended December 31, 2005 is summarized as follows:

Date of Issuance	Type of equity issuance	Number of options granted	Exercise price	Fair market value estimate per common share	Intrinsic value per share
January 24, 2005	Employee Options	65,244	$6.98	$6.98	$
June 1, 2005	Employee Options	88,000	7.64	7.64	

Significant Factors, Assumptions, and Methodologies Used in Determining Fair Value.

Factors considered by our compensation committee in establishing the fair value of our common stock at the various grant dates included the following:

- the most recent valuation of our estimated proved natural gas reserves prepared by independent reservoir engineers;
- the future price of natural gas;
- the relative risks associated with estimating production and costs from different categories of reserves;
- the discount factor used to approximate the time value of money;

- the significant uncertainty surrounding the determination of estimated quantities of natural gas reserves;
- the valuation of other assets and liabilities;
- arms-length transactions involving our common stock; and
- general industry and economic trends.

Significant Factors Contributing to the Difference between Fair Value as of the Date of Each Grant and the Price that Selling Stockholders Will Obtain From the Sale of Their Shares.

As set forth in the table above, we granted stock options with exercise prices ranging from $6.98 to $7.64 during the year ended December 31, 2005. The reasons for the difference between the exercise price range of $6.98 and $7.64 and the estimated selling range included in this offering are as follows:

- Increases in the spot and futures price of natural gas used to determine the value of our natural gas reserves. Average well head gas prices increased $0.14 per Mcf, or 2.3%, from $6.01 per Mcf at December 31, 2004 to $6.15 per Mcf at June 30, 2005. Gas prices further increased $3.87 per Mcf, or 62.9%, from June 30, 2005 to $10.02 per Mcf at December 31, 2005;

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Increases in the quantities of proved reserves owned by us and increases in the level of daily production volume resulting from our, ongoing successful drilling program at Gurnee and Pond Creek. Quantities of proved reserves increased 13 Bcf, or 6.2%, from 210 Bcf at December 31, 2004 to 213 Bcf at June 30, 2005. Quantities of proved reserves further increased 50 Bcf, or 23.5%, from June 30, 2005 to 263 Bcf at December 31, 2005; and

Increases in the market values of successful publicly traded exploration and production companies. Indices for oil and gas stock prices increased 87.14 points, or 29.3%, from 297.42 at December 2004 to 384.56 at June 2005. Indices for oil and gas stock prices further increased 66.22 points, or 17.2 %, from June 2005 to 450.78 at December 2005.

Derivative Instruments

Due to the historical volatility of natural gas prices, we have implemented a hedging strategy aimed at reducing the variability of prices we receive for our production. Currently, we use collars and fixed-price swaps as our mechanism for hedging commodity prices. We have elected not to designate any of our current derivative instruments as hedges for accounting purposes in accordance with SFAS No. 133 Derivative Instruments and Hedging Activities. As a result, we account for our derivative instruments on a mark-to-market basis, and changes in the fair value of derivative instruments are recognized as gains and losses which are included in operating expense in the period of change. While we believe that the stabilization of prices and protection afforded us by providing a revenue floor for our production is beneficial, this strategy may result in lower revenues than we would have if we were not a party to derivative instruments in times of rising natural gas prices. As a result of rising commodity prices, we recognized total losses on derivative contracts for the year ended December 31, 2005 of approximately $19.5 million. If commodity prices increase, we may recognize additional charges in future periods.

Producing Field Operations Summary

The table below presents information on gas revenues, sales volumes, production expenses and per Mcf data for the years ended December 31, 2005, 2004 and 2003. This table should be read with the discussion of the results of operations for the periods presented below.

	Years Ended December 31,		
	2005	2004	2003
	(In thousands except per Mcf)		
Gas sales	$ 41,604	$ 19,522	$ 11,700
Lease operating expenses	$ 8,687	$ 5,092	$ 1,640
Compression and transportation expenses	3,332	1,951	993
Production taxes	914	473	414
Total production expenses	$ 12,933	$ 7,516	$ 3,047
Net sales volumes (MMcf)	4,594	3,187	2,484
Per Mcf data ($/Mcf):			

Average natural gas sales price	$ 9.06	$ 6.12	$ 4.71
Average natural gas sales price realized(1)	$ 7.43	$ 5.87	$ 4.69
Lease operating expenses	$ 1.89	$ 1.60	$ 0.66
Compression and transportation expenses	$ 0.72	$ 0.61	$ 0.40
Production taxes	$ 0.20	$ 0.15	$ 0.17
Total production expenses	$ 2.81	$ 2.36	$ 1.23

(1) Average realized price includes the effects of realized losses on derivative contracts.

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Results of Operations

Year Ended December 31, 2005 compared with Year Ended December 31, 2004

The following is a discussion of significant matters affecting the operating and financial results for the year ended December 31, 2005 compared to the year ended December 31, 2004. Significant changes in sales volumes at our major properties and the White Oak Creek Sale and the Pond Creek Acquisition, which occurred in 2004 and were discussed in detail in the Overview, result in the periods not being comparable.

Selected items presented in our Consolidated Statement of Operations and Comprehensive Income on page F-4 and their percentage changes from the comparable period are presented in the table below:

	Years Ended December 31, 2005	Years Ended December 31, 2004	Percentage Change
	(In thousands)		
Gas sales	$ 41,604	$ 19,522	113%
Operating fees and other	376	1,402	(73)%
Total revenues	$ 41,980	$ 20,924	101%
Lease operating expenses	$ 8,687	$ 5,092	71%
Compression and transportation expenses	3,332	1,951	71%
Production taxes	914	473	93%
Depreciation, depletion and amortization	4,867	2,691	81%
Research and development	609	279	119%
General and administrative	3,208	2,513	28%
Realized losses on derivative contracts	7,473	815	817%
Unrealized losses (gains) from the change in market value of open derivative contracts	12,059	(542)	2,325%
Total operating expenses	$ 41,149	$ 13,272	210%
Interest expense (net of amounts capitalized)	$ (3,895)	$ (986)	295%
Income (loss) before income taxes, minority interest, and cumulative effect of change in accounting principle, net of income tax	$ (3,008)	$ 6,732	(145)%
Income tax provision	(993)	2,312	(143)%
Net income (loss) before minority interest and cumulative effect of change in accounting principle, net of income tax	$ (2,015)	$ 4,420	(146)%

Sales Volumes. Increases in wells coming on line from the ongoing drilling program and the Pond Creek Acquisition, offset partially by the White Oak Creek Sale and normal production declines, resulted in a 44% increase in sales volumes to 4.6 Bcf from 3.2 Bcf. Total net productive wells increased 42% to 313 from 220.

Gas Sales. Increases in gas prices and sales volumes resulted in an 113% increase in gas sales to $41.6 million from $19.5 million. Gas prices increased 48% to $9.06 per Mcf from $6.12 per Mcf before the effects of hedges.

Operating fees and other. A $0.8 million cash settlement from a previous joint venture partner in the prior period and a $0.29 million decrease in operating fees from the termination of contract operations resulted in a 73% decrease in operating fees and other.

Lease Operating expenses. An increase in unit costs and higher sales volumes resulted in a 71% increase in lease operating expenses to $8.7 million from $5.1 million. Lease operating expenses per Mcf increased 18% to $1.89 from $1.60. The increase in per unit lease operating expenses was primarily due to a change in the sales volume mix, which is weighted more to early stage projects with higher per unit lease operating expenses in 2005 as compared to mature projects with lower per unit lease operating expenses in 2004. The White Oak Creek Sale was the sale of a mature project with significantly lower per unit lease operating expenses than the overall per unit lease operating expenses.

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Compression and transportation expenses. An increase in unit expenses and higher sales volumes at Pond Creek resulted in a 71% increase in compression and transportation expenses to $3.3 million from $2.0 million. Compression and transportation expenses per Mcf increased 18% to $0.72 from $0.61. The increase in per unit compression and transportation expenses was primarily due to the additions of compressors to handle the increase in sales volumes and increases in firm transportation fees at Pond Creek. There are no transportation expenses at Cahaba.

Production taxes. Increases in gas sales resulted in a 93% increase in production taxes to $0.9 million from $0.5 million. A significant portion of Pond Creek sales volumes is exempt from production taxes for five years from date of first production because of a West Virginia tax exemption.

Depreciation, depletion and amortization. A 31% increase in the depletion rate for gas reserves to $1.02 from $0.78 combined with a 44% increase in sales volumes caused depreciation, depletion and amortization to increase 81% to $4.9 million from $2.7 million. The increase in the depletion rate was primarily due to a $48 million increase in the net book value of gas properties due to a purchase accounting adjustment related to the acquisition of the minority interest stock in a subsidiary, and to a lesser extent downward reserve revisions at Cahaba and increased drilling and completion costs. The depletion rate is generally calculated by dividing the net book value of gas properties by total proved reserves.

General and administrative. Increases in employee expenses, office expenses, and business taxes, resulted in a 28% increase in general and administrative to $3.2 million from $2.5 million. An increase in the number of employees due to increased activity levels, increases in salaries and bonuses of employees, and a $0.15 million one-time payment to certain executives associated with the subsidiary merger increased employee expenses. Office expenses increased due to increased rent expense and office supplies expense. Business taxes increased due to increased franchise taxes caused by increased capital subject to tax. General and administrative recoveries, reclassification and capitalized items was $5.4 million for 2005 and 2004. General and administrative recoveries, reclassifications and capitalized items primarily consist of capitalized general and administrative costs related to exploration and development activities and the reclassification of costs related to field employees involved in production activities.

Realized losses on derivative contracts. Increases in gas prices during the year ended December 31, 2005, combined with increases in the nominal volume of derivative contracts that settled during the year, caused the realized losses on derivative contracts to increase 817% to $7.5 million from $0.8 million. We enter into various gas swap and three-way collar transactions from time to time that are not designated as accounting hedges. Realized losses represent the net cash settlements paid to the derivative counterparty during the year. The realized losses are recorded in total operating expenses in the Consolidated Statement of Operations and Comprehensive Income.

Unrealized losses (gains) from the change in market value of open derivative contracts. The change in the market value of open derivative contracts during the year ending December 31, 2005 resulted in a 2,325% change to an unrealized loss of $12.1 million from an unrealized gain of $0.5 million. Increases in gas prices during the year and in the nominal volume of outstanding derivative contracts contributed to the unrealized losses. We enter into various gas swap and three-way collar transactions from time to time that are not designated as accounting hedges. Under this accounting treatment, the changes in the market value of outstanding financial instruments are recognized as gains or losses in the income statement in the period of change. The gains and losses are recorded in total operating expenses in the Consolidated Statement of Operations and Comprehensive Income.

Interest expense (net of amounts capitalized). Higher average levels of debt outstanding and higher borrowing rates on the credit facility caused interest expense (net of amounts capitalized) to increase 295% to $3.9 million from $1.0 million. Capitalized interest in 2005 and 2004 was $0.7 million and $0.1 million, respectively.

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Income tax provision. Our income tax provision includes both state and federal taxes. Our state taxes are an insignificant portion of our income tax provision. The 143% decrease in our income tax provision to a benefit of $1.0 million from an expense of $2.3 million corresponds to the net loss in 2005 from net income for the comparable year. The effective rate in 2005 was 33% compared to 34% for 2004.

Year Ended December 31, 2004 compared with Year Ended December 31, 2003

The following is a discussion of significant matters affecting the operating and financial results for the year ended December 31, 2004 compared to the year ended December 31, 2003. Significant changes in sales volumes at our major properties and the White Oak Creek Sale and the Pond Creek Acquisition, which occurred in 2004 and were discussed in detail in the Overview, result in the periods not being comparable.

Selected items presented in the Consolidated Statement of Operations and Comprehensive Income on page F-4 and their percentage changes from the comparable period are presented in the table below:

	Years Ended December 31,		Percentage
	2004	2003	Change
	(In thousands)		
Gas sales	$ 19,522	$ 11,700	67%
Operating fees and other	1,402	349	302%
Total revenues	$ 20,924	$ 12,049	74%
Lease operating expenses	$ 5,092	$ 1,640	210%
Compression and transportation expenses	1,951	993	96%
Production taxes	473	414	14%
Depreciation, depletion and amortization	2,691	2,120	27%
Research and development	279	432	(35)%
General and administrative	2,513	1,370	83%
Impairment		8	100%
Realized losses on derivative contracts	815	44	1,752%
Unrealized losses (gains) from the change in market value of open derivative contracts	(542)	102	631%
Total operating expenses	$ 13,272	$ 7,123	86%
Interest expense (net of amounts capitalized)	$ (986)	$ (232)	325%
Income (loss) before income taxes, minority interest, and cumulative effect of change in accounting principle, net of income tax	$ 6,732	$ 4,782	41%
Income tax provision	2,312	1,651	40%
Net income (loss) before minority interest, and cumulative effect of change in accounting principle, net of income tax	$ 4,420	$ 3,131	41%

Sales volumes. Increases in wells coming on line from the ongoing drilling program at Pond Creek, the beginning of development at Cahaba and the Pond Creek Acquisition, offset partially by the White Oak Creek Sale and normal production declines, resulted in a 28% increase in sales volumes to 3.2 Bcf from 2.5 Bcf. Total net productive wells increased 96% to 220 from 112.

Gas sales. Increases in gas prices and sales volumes resulted in a 67% increase in gas sales to $19.5 million from $11.7 million. Gas prices increased 30% to $6.12 per Mcf from $4.71 per Mcf before the effects of hedges. The sales price per Mcf in 2003 was reduced by the forward sale of 3,000 MMBtu/day of gas produced from White Oak Creek at a set price of $4.00/MMBtu for the period January 1, 2003 to December 31, 2003.

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Operating fees and other. A $0.8 million White Oak Creek joint interest audit settlement and a $0.2 million increase in contract operating fees, primarily increased operating fees and other by $1.1 million to $1.4 million in 2004 from $0.3 million in 2003.

Lease operating expenses. An increase in unit expenses and higher sales volumes resulted in a 210% increase in lease operating expenses to $5.1 million from $1.6 million. Lease operating expenses per Mcf increased 142% to $1.60 from $0.66. The increase in per unit lease operating expenses was primarily due to a change in the sales volume mix which is weighted more to early stage projects with higher per unit operating costs in the 2004 period as compared to mature projects with lower per unit operating expenses in the comparable period. The White Oak Creek Sale was the sale of a mature project with significantly lower per unit lease operating expenses than the overall per unit lease operating expenses.

Compression and transportation expenses. An increase in unit expenses and higher sales volumes at Pond Creek resulted in a 96% increase in compression and transportation expenses to $2.0 million from $1.0 million. Compression and transportation expenses per Mcf increased 53% to $0.61 from $0.40. The increase in per unit compression and transportation expenses was primarily due to the addition of compressors to handle the increase in sales volumes. There are no transportation expenses at Cahaba. The White Oak Creek Sale was the sale of a mature project with significantly lower per unit compression and transportation expenses than the overall per unit compression and transportation expenses.

Production taxes. Increases in gas sales resulted in a 14% increase in production taxes to $0.5 million from $0.4 million. All of Pond Creek s production in 2004 and 2003 was exempt from production taxes because the producing wells are located in West Virginia which has a production tax exemption for five years from the date of first production.

Depreciation, depletion and amortization. Increases in sales volumes and a 2.5% increase in the depletion rate to $0.80 per Mcf from $0.78 per Mcf caused depreciation, depletion and amortization to increase 27% to $2.7 million from $2.1 million. The Pond Creek Acquisition added 31.8 Bcf of proved reserves at a cost of $27 million or $0.85 per Mcf of proved reserves. The White Oak Creek Sale reduced the net book value of properties by $21 million and reduced proved reserves by 8.4 Bcf. The depletion rate is generally calculated by dividing the net book value of gas properties by total proved reserves.

General and administrative. Increases in employee expenses, professional fees and business taxes, partially offset by an increase in recoveries, reclassifications and capitalized items, resulted in an 83% increase in general and administrative to $2.5 million from $1.4 million. The hiring of additional employees due to the increase in activity levels and higher salary levels increased gross employee expenses approximately $0.9 million and a title dispute increased legal fees approximately $0.3 million. General and administrative recoveries, reclassifications and capitalized items in 2004 and 2003 were $5.4 million and $5.1 million, respectively. General and administrative recoveries, reclassifications and capitalized items primarily consist of capitalized general and administrative costs related to exploration and development activities and the reclassification of costs related to field employees involved in production activities.

Realized losses on commodity derivative contracts. Increases in gas prices during the year, combined with increases in the nominal volume of derivative contracts that settled during the year, caused the realized losses on derivative contracts to increase 1,752% to $0.8 million from $0.04 million. We enter into various gas swap and three-way collar transactions from time to time that are not designated as accounting hedges. Realized losses represent the net cash settlements paid to the derivative counterparty during the year. The realized losses are recorded in total operating expenses in the Consolidated Statement of Operations and Comprehensive Income.

Unrealized losses (gains) from the change in market value of open derivative contracts. The change in the market value of open derivative contracts for the year resulted in an unrealized gain of $0.5 million from a loss of

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$0.1 million in the comparable period. Decreases in gas prices during the period and an increase in the nominal volume of outstanding derivative contracts contributed to the decrease in unrealized losses. We enter into various gas swap and three-way collar transactions from time to time that are not designated as accounting hedges. Under this accounting treatment, the changes in the market value of outstanding financial instruments are recognized as gains or losses in the income statement in the period of change. The gains and losses are recorded in total operating expenses in the Consolidated Statement of Operations and Comprehensive Income.

Interest expense (net of amounts capitalized). Increased average debt levels and higher borrowing rates on the credit facility caused interest expense (net of amounts capitalized) to increase 325% to $1.0 million from $0.2 million during the period. Capitalized interest in 2004 and 2003 was $0.1 million and $0.1 million, respectively.

Income tax provision. Our income tax provision includes both state and federal taxes. Our state taxes are an insignificant portion of our income tax provision. The 40% increase in our income tax provision to $2.3 million from $1.7 million corresponds to the increase in net income before tax in 2004. The effective rate in 2004 and comparable period remained at approximately 34%.

Liquidity and Capital Resources

Cash Flows and Liquidity

As of December 31, 2005, we had a working capital deficit of approximately $7.4 million. This compares to a deficit of working capital of $1.3 million at December 31, 2004. The increase in the working capital deficit is primarily due to the $8.9 million derivative liability, offset partially by the related $2.9 million deferred tax asset. The derivative liability is directly affected by natural gas prices and may vary significantly from period to period. Our accounts payable balances at December 31, 2005 decreased by approximately 9% from levels at December 31, 2004, primarily as a result of the timing of payments of expenditures for our current projects. At December 31, 2005, we had $21 million available for borrowing under our revolving credit facility.

Cash flow from operating activities was $12.4 million and $10.6 million, respectively, for the years ended December 31, 2005 and 2004. In the past, cash flow from operations has been insufficient to fund our capital expenditures. In order to meet this shortfall, we have generally incurred debt under our revolving credit facility and sold additional common stock ($9.1 million of proceeds in 2004).

Cash flow from financing activities for the year ended December 31, 2005 of $44.9 million was reduced by payment of a $3 million common stock dividend by GeoMet to its stockholders prior to the merger of its subsidiary, Old GeoMet, into GeoMet.

The development of CBM fields requires substantial initial investment before meaningful production and resulting cash flows are realized. Among the factors that can be expected to affect our cash flows and liquidity are the characteristics of the field, the amount of water produced, the methods utilized to dispose of produced water, and the timing and volume of initial and subsequent natural gas production. We estimate total capital expenditures in 2006 will be approximately $90 million with approximately 80% allocated to development projects, 12% to exploration projects, 4% to leasehold acquisitions and the remaining 4% for other items (primarily capitalized overhead and interest and administrative capital expenditures), representing an increase of approximately $30 million over our actual 2005 capital expenditures. The increase is primarily attributable to increased development expenditures at Pond Creek and Cahaba. As of March 31, 2006 we have approximately $62 million of available borrowing capacity under our revolving credit facility.

Based upon current expectations, we believe that we will have adequate resources from cash flows from operations, and from proceeds from credit facility borrowing and additional equity financings to fund our 2006 capital expenditures and other working capital needs.

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If natural gas commodity prices decrease from their current levels for an extended period, our ability to finance our planned capital expenditures could be affected negatively. Furthermore, amounts available for borrowing under our revolving credit facility are largely dependent on our level of estimated proved reserves and current natural gas prices. If either our estimated proved reserves or natural gas prices decrease, amounts available to us to borrow under our revolving credit facility could be negatively affected. If our cash flows are less than anticipated, amounts available for borrowing under our revolving credit facility are reduced or we are unable to sell equity at acceptable prices, we may be forced to defer planned capital expenditures.

Price Risk Management Activities

The energy markets have historically been very volatile, and there can be no assurance that gas prices will not be subject to wide fluctuations in the future. In an effort to reduce the effects of the volatility of the price of natural gas on our operations, management has adopted a policy of hedging natural gas prices from time to time primarily through the use of commodity price swap agreements and costless collar arrangements. While the use of these hedging arrangements limits the downside risk of adverse price movements, it also limits future gains from favorable movements. Our price risk management policy strictly prohibits the use of derivatives for speculative positions.

We enter into hedging transactions that increase our statistical probability of achieving our targeted level of cash flows. We have at times hedged forward for periods up to two years. We generally limit the amount of these hedges to no more than 50% to 60% of the then expected gas production for such future period. We have historically used swaps, costless collars and three-way costless collars in our hedging activities. Swaps exchange floating price risk in the future for a fixed price at the time of the hedge. Costless collars set both a maximum ceiling and a minimum floor future price. Three-way costless collars are similar to regular costless collars except that, in order to increase the ceiling price, we agree to limit the amount of the floor price protection to a predetermined amount, generally between $1.00 and $1.50 per MMBtu. Currently, our hedge strategy favors the use of three-way collars that allow us to retain more price upside. We have not designated any of our price risk management activities as accounting hedges and, therefore, have accounted for these transactions using the mark-to-market accounting method. Generally, we incur accounting losses during periods where prices rise above the level of our hedges and gains during periods where prices drop below the level of our hedges. Until 2005, the impact of this method of accounting was not significant; however, the significant increase in gas prices in 2005, particularly in the third quarter in response to Hurricanes Katrina and Rita, resulted in approximately $19.5 million in hedging losses for the year ended December 31, 2005. A total of $12.1 million of such losses were unrealized at December 31, 2005 and had no impact on cash flows.

We believe that the use of derivative instruments does not expose us to material risk. However, the use of derivative instruments could materially affect our results of operations depending on the future prices of natural gas. Nevertheless, we believe that use of these instruments will not have a material adverse effect on our financial position or liquidity. For a summary of accounting policies related to derivative instruments, see Note 2 to our consolidated financial statements included elsewhere in this prospectus.

As of December 31, 2005, we had the following hedge contracts outstanding:

Instrument Type	Production Period	Volumes (MMBtu)	Weighted Average Floor Price ($/MMBtu)	CAP ($/MMBtu)

Collars (3 way)	January 1	December 31, 2006	4,258,000	$	5.99	$7.27	$	9.05
Collars (3 way)	January 1	December 31, 2007	1,756,000	$	6.60	$7.98	$	10.28

For the two month period ending February 28, 2006, our realized losses on settled hedges were approximately $0.6 million.

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Sensitivity analyses of the incremental effects on pre-tax loss for the year ended December 31, 2005 of a hypothetical 10% and 25% change in natural gas prices for outstanding hedge contracts as of December 31, 2005 are provided in the following table:

	Incremental (Increase)/ Decrease in pre-tax loss assuming a hypothetical price increase and decrease of(1):	
	10%	25%
	(In thousands)	
Price increase	$ (4,923)	$ (12,947)
Price decrease	$ 4,437	$ 9,969

(1) We remain at risk for possible changes in the market value of these derivative contracts; however, any unfavorable increases would be partly offset by higher revenues due to higher sales prices for our gas. The favorable effect of this offset is not reflected in the sensitivity analyses.

We have reviewed the financial strength of our hedge counterparties and believe our credit risk to be minimal. Our hedge counterparties are participants in our credit agreement and the collateral for the outstanding borrowings under our credit agreement is used as collateral for our hedges.

Capital Expenditures and Capital Resources

	Years Ended December 31,		
	2005	2004	2003
	(In thousands)		
Capital expenditures:			
Leasehold acquisition	$ 2,012	$ 1,571	$ 2,109
Exploration	8,620	6,759	17,374
Development	46,397	49,023	14,623
Acquisitions		27,046	
Other items (primarily capitalized overhead and interest)	2,173	1,790	1,963
Total capital expenditures	$ 59,202	$ 86,189	$ 36,069

Our capital expenditures for the year ending December 31, 2005 were approximately equal to the comparable 2004 period, exclusive of the Pond Creek Acquisition. Development expenditures declined slightly due to a decrease in Gurnee field spending partially offset by increased spending at Pond Creek. Exploration spending increased due primarily to Peace River project expenditures. Our capital expenditures for 2004, exclusive of the Pond Creek Acquisition and the White Oak Creek Sale, increased approximately 62% compared to 2003 as a result of increased development expenditures at the Gurnee field.

Credit Facility

We have recently entered into a $150 million amended and restated credit agreement with Bank of America, N.A., as agent, and other lenders. Availability under the amended credit agreement is subject to a borrowing base, which is currently set at $120 million. The borrowing base is subject to semi-annual redeterminations. The lenders also have the right to require one additional redetermination in any fiscal year. The amended credit agreement provides for interest to accrue at a rate calculated, at our option, at either the adjusted base rate (which is the greater of the agent s base rate or the federal funds rate plus one half of one percent) or the London Interbank Offered Rate (LIBOR) plus a margin of 1.00% to 2.00% based on borrowing base usage. Borrowings under the amended credit agreement are secured by first priority liens on substantially all of our assets including equity interests in our subsidiaries. All outstanding borrowings under the amended credit agreement become due and payable on January 6, 2011.

We are subject to financial covenants requiring maintenance of a minimum current ratio and a minimum interest coverage ratio. Our ratio of consolidated current assets (defined to include amounts available under our

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borrowing base) to our consolidated current liabilities is not permitted to be less than 1 to 1 as of the end of any fiscal quarter, and our ratio of consolidated EBITDA for the four preceding quarters at the end of each fiscal quarter to the sum of our consolidated net interest expense for the preceding four quarters period plus letter of credit fees accruing during such quarter is not permitted to be less than 2.75 to 1. Consolidated EBITDA as defined in the amended credit agreement excludes other non-cash charges deducted in determining net income (loss), which would include unrealized losses from the change in the market value of open derivative contracts. In addition, we are subject to covenants restricting or prohibiting cash dividends and other restricted payments, transactions with affiliates, incurrence of debt, consolidations and mergers, the level of operating leases, assets sales, investments in other entities, and liens on properties. A breach of any of the covenants imposed on us by the terms of our credit facility, including the financial covenants, could result in a default under such indebtedness. In the event of a default, the lenders could terminate their commitments to us, and they could accelerate the repayment of all of our indebtedness. In such case, we may not have sufficient funds to pay the total amount of accelerated obligations, and our lenders could proceed against the collateral securing the facility. Any acceleration in the repayment of our indebtedness or related foreclosure could adversely affect our business.

In addition, the borrowing base under our credit facility is redetermined semi-annually and may also be redetermined once each fiscal year for any reason upon request by lenders representing 66.66% of the total commitment under our credit facility. Redeterminations are based upon a number of factors, including commodity prices and reserve levels. The next scheduled redetermination is to occur as of June 30, 2006. Upon a redetermination, we could be required to repay a portion of our bank debt. We may not have sufficient funds to make such repayments, which could result in a default under the terms of the credit facility and an acceleration of our indebtedness.

At December 31, 2005, the amount of borrowings outstanding under our then existing credit facility was $99 million, accruing interest at an average annual rate of 6.59%. At March 31, 2006 our borrowings outstanding under our new credit facility were approximately $58 million leaving us with $62 million available for future borrowings.

At March 31, 2006, we did not have any hedges in place to reduce our risk to increases in interest rates.

All of the debt outstanding under our credit facility accrues interest at floating or market rates. Fluctuations in market interest rates will cause our interest costs to fluctuate. Based upon the balance of our bank debt at December 31, 2005, a 1% change in market interest rates would have increased interest expense and negatively impacted our annual cash flows by approximately $990,000.

Contractual Commitments

We have numerous contractual commitments in the ordinary course of business, debt service requirements and operating lease commitments. The following table summarizes these commitments at December 31, 2005:

	Beginning January 1, 2006(1)				
	One Year	2-4 Years	5-6 Years	More than 6 Years	Total
	(In thousands)				

Long-term debt and other obligations(2)	$ 86	$ 309	$ 99,618	$	$ 100,013
Interest expense on bank credit facility(3)	5,762	17,287	5,841		28,890
Operating lease obligations	1,185	3,059	1,283	210	5,737
Asset retirement obligations	52			1,838	1,890
Derivative liability	8,932	2,612			11,544
Firm transportation contracts	1,100	1,506	418		3,024
Other operating commitments	1,067	530			1,597
Total commitments	$ 18,184	$ 25,303	$ 107,160	$ 2,048	$ 152,695

(1) Does not include a contingent payment related to the Pond Creek Acquisition because the amount is not contractually determinable until December 31, 2007. The contingent payment, if any, will be paid on March 31, 2008 and cannot exceed $3 million.

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(2) Maturities based on the January 2006 amended bank credit agreement terms, which extended the maturity date to January 6, 2011.
(3) Assumes an annual rate on a 30-day LIBOR of 4.57% plus the current 1.25% margin for a total interest rate of 5.82%.

Off-Balance Sheet Arrangements

Currently, we do not have any off-balance sheet arrangements.

Recent Accounting Pronouncements

In September 2005, the Emerging Issues Task Force (EITF) reached a consensus on Issue No. 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty. EITF Issue 04-13 requires that purchases and sales of inventory with the same counterparty in the same line of business should be accounted for as a single non-monetary exchange, if entered into in contemplation of one another. The consensus is effective for inventory arrangements entered into, modified or renewed in interim or annual reporting periods beginning after March 15, 2006. We do not expect the adoption of this EITF Issue to have a material impact on our consolidated financial position, results of operations or cash flows.

In June 2005, the Financial Accounting Standard Board (FASB) issued FASB Statement No. 154, *Accounting Changes and Error Corrections*- a replacement of APB Opinion No. 20 and FASB Statement No. 3. This statement provides guidance on the accounting for and reporting of accounting changes and error corrections. It establishes, unless impracticable, retrospective application as the required method for reporting a change in accounting principle in the absence of explicit transition requirements specific to the newly adopted accounting principle. This statement also provides guidance for determining whether retrospective application of a change in accounting principle is impracticable and for reporting a change when retrospective application is impracticable. The correction of an error in previously issued financial statements is not an accounting change. However, the reporting of an error correction involves adjustments to previously issued financial statements similar to those generally applicable to reporting an accounting change retrospectively. Therefore, the reporting of a correction of an error by restating previously issued financial statements is also addressed by this statement. This statement shall be effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. The adoption of this statement had no effect on our financial statements.

In December 2004, the FASB issued Statement of Financial Accounting Standards No. 153, Exchanges of Nonmonetary Assets, an Amendment of Accounting Principles Board (APB) Opinion No. 29, which provides all nonmonetary asset exchanges that have commercial substance must be measured based on fair value of the assets exchanged and any resulting gain or loss recorded. An exchange is defined as having commercial substance if it results in a significant change in expected future cash flows. Exchanges of operating interests by oil and gas producing companies to form a joint venture continue to be exempted. APB Opinion No. 29 previously exempted all exchanges of similar productive assets from fair value accounting, therefore resulting in no gain or loss recorded for such exchanges. SFAS No. 153 became effective for fiscal periods beginning on or after June 15, 2005. We adopted SFAS No. 153 effective July 1, 2005. The adoption of SFAS No. 153 did not have a material impact on our financial statements.

In March 2005, the Financial Accounting Standard Board (FASB) issued FASB Interpretation (FIN) No. 47 (FIN 47), *Accounting for Conditional Asset Retirement Obligations*. FIN 47 clarifies the definition and treatment of conditional asset retirement obligations as discussed in FASB Statement No. 143, *Accounting for Asset Retirement Obligations* (FAS 143). A conditional asset retirement obligation is defined as an asset retirement activity in which the timing and/or method of settlement are dependent on future events that may be outside our control. FIN 47 states that we must record a liability when incurred for conditional asset retirement obligations if the fair value of the obligation is reasonably estimable. This interpretation is intended to provide more information about long-lived assets, future cash outflows for these obligations, and more consistent recognition

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of these liabilities. FIN 47 is effective for fiscal years ending after December 15, 2005. The release of FIN 47 did not affect the method we were applying to accrue asset retirement obligations, therefore, the adoption of FIN 47 had no effect on our financial statements.

In December 2004, the FASB issued SFAS No. 123(R), *Share-Based Payment*, which establishes accounting standards for all transactions in which an entity exchanges its equity instruments for goods and services. SFAS No. 123(R) focuses primarily on accounting for transactions with employees, and carries forward without change prior guidance for share-based payments for transactions with non-employees. SFAS No. 123(R) eliminates the intrinsic value measurement objective in APB Opinion 25 and, except in certain circumstances, requires us to measure the cost of employee services received in exchange for an award of equity instruments based on the fair value of the award on the date of the grant. The standard requires grant date fair value to be estimated using either an option-pricing model which is consistent with the terms of the award or a market observed price, if such a price exists. If such fair value cannot be reasonably estimated because it is not practicable to estimate the expected volatility of our share price, we are required to estimate a value calculated by substituting the historical volatility of an appropriate industry sector index for the expected volatility of our share price. Such cost must be recognized over the period during which an employee is required to provide service in exchange for the award (which is usually the vesting period). The standard also requires us to estimate the number of instruments that will ultimately be issued, rather than accounting for forfeitures as they occur.

We adopted SFAS No. 123(R) on January 1, 2006 using the prospective transition method. Under the prospective transition method equity compensation cost will be recognized in the consolidated statement of operations based on fair value for all new awards and existing awards that are modified, repurchased or cancelled after the required effective date of January 1, 2006. For awards outstanding as of January 1, 2006, we will continue using the accounting principles originally applied to those awards before adoption. We are in the process of implementing SFAS No. 123(R). The adoption of SFAS No. 123(R) on January 1, 2006 did not have an impact on our financial position or statement of operations. Subsequent to adoption, the effect of SFAS No. 123(R) cannot be predicted at this time because it will depend on the level of share-based awards granted in the future.

Quantitative and Qualitative Disclosures about Market Risk

For a discussion of our commodity and interest rate risks, see the discussions set forth above under Liquidity and Capital Reserves Price Risk Management Activities and Liquidity and Capital Reserves Credit Facility above.

Foreign Currency Exchange Rate Risk

We began exploratory operations in Canada in the fourth quarter of 2004 and do not have operations in any other foreign countries. We do not hedge our foreign currency risk and are exposed to foreign currency exchange rate risk in the Canadian dollar. Because our Canadian project is exploratory, the effect of changes in the exchange rate does not impact our revenues or expenses but primarily affects the costs of unevaluated properties. We continue to monitor the foreign currency exchange rate in Canada and may implement measures to protect against the foreign currency exchange rate risk in the future.

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BUSINESS

About GeoMet

We are engaged in the exploration, development, and production of natural gas from coal seams (coalbed methane or CBM). Our principal operations and producing properties are located in the Cahaba Basin in Alabama and the Appalachian Basin in West Virginia and Virginia. GeoMet was originally founded as a consulting company to the coalbed methane industry in 1985 and has been active as an operator and developer of coalbed methane properties since 1993. We control a total of approximately 255,000 net acres of coalbed methane development rights, primarily in Alabama, West Virginia, Virginia, Louisiana, Colorado, and British Columbia. We control a total of approximately 77,000 net acres of coalbed methane development rights in the Gurnee field in the Cahaba Basin and in the Pond Creek field in the Appalachian Basin, and we also control the balance of 178,000 net acres of coalbed methane development rights primarily in north central Louisiana, British Columbia, West Virginia, and Colorado. We have conducted substantial gas desorption testing and drilling of core holes throughout our property base. We believe our extensive undeveloped acreage position in the Gurnee field in the Cahaba Basin and in the Pond Creek field in the Appalachian Basin contains a total of 586 additional drilling locations.

At December 31, 2005, we had 262.5 Bcf of estimated proved reserves with a PV-10 of approximately $880 million using gas prices in effect at such date. See Selected Historical Consolidated Financial and Operating Data Reconciliation of Non-GAAP Financial Measures on page 24 for additional information regarding PV-10. Our estimated proved reserves are 100% coalbed methane and 74% proved developed. For the month of March 2006, our net gas sales totaled approximately 15,500 Mcf per day. For 2005, our total capital expenditures were approximately $60 million and our development expenditures for the development of the Gurnee and Pond Creek fields was approximately $46.4 million. We intend to increase our total capital spending in 2006 by approximately 50% to $90 million and development expenditures by approximately 57% to approximately $72 million to accelerate the drilling of the Gurnee and Pond Creek fields.

Areas of Operation

Cahaba Basin

We have the development rights to approximately 41,800 net CBM acres throughout the Cahaba Basin of central Alabama, which is adjacent to the Black Warrior Basin. At December 31, 2005, approximately 55% of our estimated proved reserves, or 145.1 Bcf, were located in the Gurnee field within the Cahaba Basin, of which approximately 78% were classified as proved developed. At December 31, 2005, we had developed 24% of our Cahaba Basin CBM acreage. We own a 100% working interest in the area and are the operator. As of March 1, 2006, we had drilled 143 wells in the Gurnee field, of which 137 were producing (the remainder of which were pending completion or hook-up or were venting gas), with net daily sales of gas averaging approximately 4,400 Mcf for the month of March 2006. Our undeveloped CBM acreage in the Cahaba Basin contains 366 additional drilling locations, based on 80-acre spacing. In 2006, we intend to spend approximately $45 million of our capital expenditure budget to develop and drill approximately 75 wells in the Cahaba Basin.

We extract gas from six coal groups within the Pottsville coal formation at depths ranging from 700 feet to 3,400 feet. At these depths, overall seam thickness in this area averages approximately 50 feet of high volatile bituminous rank coal. A total of 30 core holes have been drilled and over 540 gas desorption tests have been conducted on our acreage to determine the gas content of the coal and to define the coalbed methane resource under a substantial portion of the acreage in our leasehold position.

We have constructed and operate an approximate 38.5-mile pipeline from the Cahaba Basin to the Black Warrior River for the disposal of produced water under a permit issued by the Alabama Department of Environmental Management. This pipeline has a design capacity of approximately 45,000 barrels of water per day. We also operate a water treatment facility in the Gurnee field to condition the produced water prior to injection into the pipeline and a discharge pond at the river to aerate the water prior to disposal. We believe that these facilities will meet all of our future water disposal requirements for the Gurnee field.

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We control and operate a 9.2-mile, 12-inch high pressure steel pipeline and a gas treatment and compression facility through which we gather, dehydrate, and compress our gas for delivery into the Southern Natural Gas pipeline system. We plan to re-activate an additional 5.6 miles of existing 12-inch steel pipeline and to add an additional 2.5 miles of newly constructed 12-inch steel pipeline in 2006.

Appalachian Basin

In the Appalachian Basin of southern West Virginia and southwestern Virginia, we have the rights to develop approximately 56,000 net CBM acres, approximately 35,000 of which are in our Pond Creek field. At December 31, 2005, approximately 44% of our estimated proved reserves, or 114.5 Bcf, were located within the Pond Creek field, of which approximately 70% were classified as proved developed. We own a 100% working interest in the area and are the operator. As of March 1, 2006, we had drilled 162 wells in the Pond Creek field, of which 154 were producing (the remainder of which are pending completion or hook-up), with net daily sales of gas averaging approximately 9,900 Mcf for the month of March 2006. Our undeveloped CBM acreage in the Pond Creek field contains 220 additional drilling locations based on 80-acre spacing. In 2006, we intend to spend approximately $20 million of our capital expenditure budget to develop and drill approximately 40 wells in the Pond Creek field.

We extract gas from up to an average of 12 coal seams within the Pocahontas and New River coal formations at depths ranging from 430 feet to 2,400 feet. At these depths overall coal thickness in this area ranges from 10 to 30 feet of high quality, low-medium volatile bituminous rank Pennsylvanian Age coal. Due to mining activity, it has been long known that these coal groups are gas rich. A total of 39 core holes have been drilled in the area and a geographically extensive gas desorption testing program has been conducted to determine the gas content of the coal and to define the coalbed methane resource under a substantial portion of our leasehold position.

CBM wells in the Pond Creek field produce comparatively lower levels of water. Produced water is either used in our operations or injected into a disposal well that we own and operate. We believe this disposal well will meet our future water disposal requirements in the Pond Creek field.

Our gas is gathered into our central dehydration and compression facility and delivered into the Cardinal States Gathering System for redelivery into the Columbia Gas Transmission Corporation gas pipeline system. Our gathering agreement with Cardinal States terminates on April 30, 2007. We have initiated right-of-way acquisitions, permitting, and construction of our own 11-mile pipeline to be constructed at an estimated cost of $5 to $6 million, which we plan to interconnect with Jewell Ridge, a new interstate pipeline. East Tennessee Natural Gas, LLC (ETNG), a subsidiary of Duke Energy Corporation, will construct the Jewell Ridge pipeline. The Jewell Ridge Pipeline is expected to be in service before the end of 2006. On March 28, 2006 we executed a precedent agreement with ETNG which, subject to satisfaction of certain conditions, obligate the parties to enter into two long-term firm transportation agreements. The agreements will have maximum daily quantities of 15,000 decatherms and 10,000 decatherms per day, respectively, with primary terms of 15 years and 10 years, respectively.

British Columbia

Our Peace River Project is comprised of approximately 33,000 gross acres (16,500 net acres) along the Peace River near Hudson s Hope, British Columbia. We are conducting operations on this project through an exploration and development agreement with a third party. We will earn a 50% working interest in this leasehold by spending $7.2 million on an evaluation program. We have spent approximately $5.5 million of this amount from project inception through December 31, 2005. We expect to complete our earning obligations in 2006 and to operate this project going forward. We have drilled three core holes targeting the Lower Cretaceous Gething coal formation. Multiple, mostly thin, coal seams exist at depths from 1,000 to 3,000 feet. At these depths, coals

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are medium volatile bituminous rank. We believe that the gas content and coal thickness under our acreage position are favorable for CBM development. We have recently drilled and completed two production test wells and a water disposal well and testing operations are in process.

North Central Louisiana

In Winn, LaSalle, and Caldwell Parishes of Louisiana, we are conducting an evaluation of the coals within the Wilcox Formation. We operate the project with a 100% working interest. As of December 31, 2005, we had a total of approximately 119,000 net acres under lease. The Wilcox is a thick deltaic deposit of Eocene age, composed primarily of sandstone, siltstone, shale, and coal. The coals are low rank, being classified as sub-bituminous and lignitic. Multiple, mostly thin, coal seams exist at depths from 2,000 to 3,500 feet. We have drilled 17 exploration or production test wells and two water disposal wells. We have also conducted 60 gas desorption tests from a sample of nine of these wells to determine the gas content of the coal and to define the potential gas resources. We believe that the gas content and coal thickness under our acreage position are favorable for CBM development. We are currently evaluating producibility issues related to zonal isolation of adjacent water sands and related water encroachment in this area.

Piceance Basin of Colorado

We also hold a total of approximately 16,900 net CBM acres of leasehold in the Piceance Basin in Mesa County, Colorado, of which approximately 14,600 net CBM acres are located in our Cameo prospect in the southwestern portion of the Piceance Basin. We are targeting the Cameo coals within a 200-foot interval of the Williams Fork formation at a depth of about 2,000 feet. We have drilled one core hole and have conducted gas desorption tests on the core. We believe that the gas content and coal thickness under our acreage position are favorable for CBM development. We are actively pursuing opportunities to increase our acreage position in this area.

History of GeoMet

Our predecessor, GeoMet, Inc., an Alabama corporation (Old GeoMet), was founded in 1985 by three geologists (the Founders) with backgrounds in the coal mining and related coal degasification industry. The Founders became directly involved with coalbed methane in 1977, working for USX Corporation in developing the first large-scale degasification field in the United States at the Oak Grove Mine in Alabama. This project became the model for subsequent coalbed methane projects in the Black Warrior basin. Our staff has been involved in the development of over thirty percent of the coalbed methane wells currently producing in the Black Warrior basin.

During our early years, our staff consulted extensively with the Gas Research Institute (GRI) in the research and development of new technology for the industry and with many of the companies involved in the early development of coalbed methane, including Taurus (now Energen), Amoco, Chevron, and River Gas Corporation (River Gas). In addition to work done in the United States, we have evaluated or consulted on coalbed methane projects in Australia, Bangladesh, Canada, China, Colombia, Czechoslovakia, Hungary, Israel, Poland, South Africa, Switzerland, the United Kingdom, Venezuela, and Zimbabwe.

In 1986, the Founders acquired a 25% equity interest in River Gas and we provided the technical expertise in connection with the development of the Blue Creek field in the Black Warrior Basin of Alabama. Dominion Energy acquired the Blue Creek field from River Gas in 1992. In 1993, following the sale of the Founders equity interest in River Gas, we ceased consulting services and began to participate in the initiation and development of coalbed methane projects. Due to capital constraints, this participation usually was in the form of relatively small earned interests. The White Oak Creek field in the Black Warrior Basin and the Apache Canyon field in the Raton Basin were developed in this manner.

Shareholders of Old GeoMet sold 80% of their ownership in Old GeoMet in December 2000 to GeoMet Resources, Inc., a Delaware corporation (Resources), a special purpose entity formed by J. Darby Seré,

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William C. Rankin, and Yorktown Energy Partners IV, L.P. In connection with this purchase, Resources committed an additional $40 million to Old GeoMet to fund future coalbed methane development and Messrs. Seré and Rankin assumed the positions of President and Chief Executive Officer and Executive Vice President and Chief Financial Officer, respectively. Old GeoMet and Resources merged in April 2005 and Resources changed its name to GeoMet, Inc.

Estimated Proved Reserves

The following tables set forth certain information with respect to our estimated proved reserves by field as of December 31, 2005. Reserve volumes and values were determined under the method prescribed by the SEC which requires the application of period-end prices and costs held constant throughout the projected reserve life. The reserve information as of December 31, 2005 is based on estimates made in a reserve report prepared by DeGolyer and MacNaughton, independent petroleum engineers. A summary of DeGolyer and MacNaughton s report on our estimated proved reserves as of December 31, 2005 is attached to this memorandum as Appendix A.

	Estimated Proved Reserves	
Field	**Proved Developed Producing**	**Proved**