GeoMet, Inc.
Form S-1/A
July 27, 2006
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As filed with the Securities and Exchange Commission on July 27, 2006

Registration No. 333-131716

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Amendment No. 6

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 JULY 27, 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 $10.00 per share and $12.00 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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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 Coalbed Methane 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. At December 31, 2005, we controlled 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 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 May 2006, our net gas sales averaged approximately 16,500 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 were approximately $46.4 million. 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, of which we had spent $10.3 million as of March 31, 2006. For 2006, we estimate that our total capital expenditures will be approximately $90 million, of which we had spent $13.4 million as of March 31, 2006.

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. Net daily sales of

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gas averaged approximately 5,200 Mcf for the month of May 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. As of March 31, 2006, we had spent $6.6 million of this budget and drilled 17 wells.

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 daily sales of gas averaged approximately 10,000 Mcf for the month of May 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. As of March 31, 2006, we had spent $3.7 million of this budget and drilled nine wells.

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 36,573 gross acres (18,287 net acres), including 3,573 gross acres (1.787 net acres) acquired in May 2006, 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 $7.0 million of this amount from project inception through March 31, 2006. We completed our earning obligations in May 2006 and will continue 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 drilled and completed two production test wells and recompleted a third production test well and a water disposal well. We are currently conducting testing operations on these wells.

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

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total of approximately 119,000 net acres under lease. 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 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 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 seven 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 drilling locations represent locations specifically identified and scheduled by management as an estimate of our future multi-year drilling activities on existing acreage. Of the total locations shown in the table, 130 are classified as proved undeveloped locations.

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

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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.

- 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.

- Pursue opportunistic CBM producing property acquisitions.

- Optimize financial flexibility by maintaining unused capacity under our bank revolving credit facility. We have a five-year, $180 million revolving credit facility with a $150 million borrowing base, of which $73.0 million was available for borrowing as of July 27, 2006.

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.

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, a material adverse change in our gas reserves due to factors other than gas pricing changes, our ability to transport our gas to markets, 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 but after the initial purchaser s discount) 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)	37,464,021 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 4,850,000 shares of our common stock that we intend to issue and sell in our initial public offering, up to 750,000 shares of our common stock if the underwriters exercise their option to purchase additional shares in our initial public offering, options to purchase 1,770,990 shares of our common stock outstanding as of March 31, 2006, of which 1,682,990 were exercisable within 60 days.

(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, 322,334 shares issued upon the exercise of stock options prior to March 31, 2006, and 4,850,000 shares issued in our initial public offering.

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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.

	Three Months Ended March 31,		Years Ended December 31,		
	2006	2005	2005	2004	2003
	(Unaudited)				
	(In thousands, unless otherwise indicated)				
STATEMENT OF OPERATIONS AND COMPREHENSIVE INCOME DATA:					
Total revenues	$ 12,311	$ 6,507	$ 41,980	$ 20,924	$ 12,049
Lease operating expenses, compression and transportation expenses and production taxes	4,186	2,930	12,933	7,517	3,047
Depreciation, depletion and amortization	1,834	885	4,867	2,691	2,120
Research and development	69	1	609	278	432
General and administrative	1,020	751	3,208	2,513	1,370
Impairment of non-operating assets					8
Realized losses (gains) on derivative contracts	556	(165)	7,473	815	44
Unrealized losses (gains) from the change in market value of open derivative contracts	(9,074)	4,839	12,059	(542)	102
Income from operations	13,680	(2,734)	831	7,652	4,926
Other expenses and interest, net	866	592	3,839	920	144
Income tax expense (benefit)	5,652	(1,106)	(993)	2,312	1,651
Minority interest			(442)	584	571
Cumulative effect of change in accounting method		(507)			19
Net income (loss)	$ 7,163	$ (1,713)	$ (1,573)	$ 3,836	$ 2,541
BALANCE SHEET DATA (at period end):					
Working capital (deficit)	$ (8,384)	$ (6,388)	$ (7,368)	$ (1,251)	$ 5,133
Total assets	$ 260,951	$ 159,284	$ 247,909	$ 142,090	$ 81,505
Long-term debt	$ 58,377	$ 67,467	$ 99,926	$ 51,513	$ 10,102
Stockholders equity	$ 147,214	$ 60,975	$ 95,422	$ 65,692	$ 52,754
OTHER DATA:					
Net cash provided by operating activities	$ 10,504	$ 2,696	$ 12,433	$ 10,580	$ 10,801
Net cash used in investing activities	$ (13,038)	$ (18,134)	$ (59,661)	$ (66,193)	$ (36,341)
Net cash provided by financing activities	$ 3,270	$ 15,948	$ 44,906	$ 50,192	$ 30,534
Capital expenditures	$ 13,327	$ 18,130	$ 59,817	$ 86,189	$ 36,069
Net sales volume (Bcf)	1.4	1.0	4.6	3.2	2.5
Average natural gas sales price ($ per Mcf)	$ 9.08	$ 6.38	$ 9.06	$ 6.12	$ 4.71
Average natural gas sales price ($ per Mcf) realized(1)	$ 8.64	$ 6.56	$ 7.43	$ 5.87	$ 4.69
Total production expenses ($ per Mcf)	$ 3.09	$ 2.94	$ 2.81	$ 2.36	$ 1.23
Expenses: ($ per Mcf)					
Lease operating expenses	$ 2.09	$ 2.09	$ 1.89	$ 1.60	$ 0.66
Compression and transportation expenses	$ .79	$ .72	$ .72	$ 0.61	$ 0.40
Production taxes	$ .20	$ .13	$ .20	$ 0.15	$ 0.17
Research and development	$ .05	$	$ .13	$ 0.09	$ 0.17
General and administrative	$ .75	$ .75	$ .70	$ 0.79	$ 0.55
Depreciation, depletion & amortization	$ 1.35	$ .89	$ 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)	$ 15.5	$ (1.3)	$ 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.

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Over time, material changes to reserve estimates may be made, taking into account the results of actual drilling, 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.

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.

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Our ability to market the gas we produce depends in substantial part on the availability and capacity of pipelines systems owned and operated by third parties. Operational impediments on these pipeline systems may hinder our access to natural gas markets or delay our production.

The availability of a ready market for our natural gas production depends on a number of factors, including the proximity of our reserves to pipelines, capacity constraints on pipelines, and disruption of transportation of natural gas through pipelines. We transport the natural gas we produce principally through pipelines owned by third parties. If we cannot access these third-party pipelines, or if transportation of gas through any of these pipelines is disrupted, we may be required to shut in or curtail production from some of our wells or seek alternate methods of transportation of our production. If any of these were to occur, our revenues would be would be reduced, which would in turn have a material adverse effect on our financial condition and results of operations.

The natural gas we produce from the Pond Creek field in the Appalachian Basin is gathered at our central dehydration and compression facility and is delivered into the Cardinal States Gathering Company (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. However, we are currently constructing a 12-mile pipeline to transport the natural gas we produce from the Pond Creek field into the Jewell Ridge Pipeline, which is currently being constructed by East Tennessee Natural Gas, LLC, a subsidiary of Duke Energy Corporation. Upon completion of our new pipeline, it will no longer be necessary for us to access the Cardinal States gathering system to transport our gas to market. Pocahontas Mining Limited Liability Company (PMC) owns a portion of the land through which our new pipeline will be constructed and has granted us an easement to construct the pipeline on this land under a right-of-way agreement. CNX Gas Company LLC (CNX), the parent company of Cardinal States, has recently notified us that it believes that the pipeline right-of-way granted to us by PMC is invalid and that it has the exclusive right to transport natural gas across PMC s property. Thereafter, CNX gated certain access roads to PMC s property, impeding the construction of our pipeline; however, we have continued constructing the pipeline on acreage to which we have access.

We and PMC have applied for a temporary and permanent injunction in the Circuit Court of Buchanan County, Virginia to prevent CNX from impeding our access to the property and are also seeking a declaration of our rights under the right-of-way agreement. The court conducted evidentiary hearings on June 15, 2006 and July 6, 2006. At the hearings the court ordered CNX to allow us and PMC access to the property over and across the existing roads and directed the parties to prepare a scheduling order setting forth timelines for discovery and setting the trial date for this matter for November 15, 2006. On June 30, 2006, CNX filed a counterclaim against PMC and us seeking a declaratory judgment from the court that CNX has superior rights to our rights to the surface of the PMC property and that CNX has the exclusive right to construct pipelines, transport gas, and use roads on the PMC property.

In the event we are unsuccessful in obtaining a favorable declaratory judgment, we may be required to construct an alternate pipeline at a cost in excess of $12 million, change the planned route of the pipeline we are currently constructing at a cost that could add more than $5 million to the cost of construction of the pipeline, pay CNX an access fee for any gas transported across the PMC property at a rate up to 3.5% of the gross proceeds from the sale of such gas, or seek other transportation alternatives through pipelines owned by third parties. We do not know what the cost of other transportation alternatives with third parties would be at this time, but we believe that such cost would be significantly in excess of the costs related to the construction and operation of our own pipeline. Any of these alternatives may result in our inability to deliver the gas we produce from the Pond Creek field to market for some period of time. If we are unable to deliver our gas to market for a prolonged period of time, our financial position, results of operations and cash flow will be materially adversely affected.

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

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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;
- 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

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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.

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 and will be completed by December 15, 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.

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.

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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 identified drilling locations are scheduled over a period in excess of five years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management has specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our acreage located in the Pond Creek field and the Cahaba Basin. As of December 31, 2005, we had identified and scheduled 586 gross drilling locations on this acreage. These scheduled drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including natural gas prices, the availability of capital, costs, drilling results, our ability to transport our gas to market, regulatory approvals and other factors. Because of these uncertainties, we do not know if all of the potential drilling locations we have identified will ever be drilled or if we will be able to produce natural gas from these or any other potential drilling locations. In addition, unless we drill a minimum number of wells annually on this acreage, the leases covering such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

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.

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

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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.

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

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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 recognized total losses on our outstanding hedges of approximately $19.5 million (consisting of a $7.5 million realized loss and a $12 million unrealized loss). 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 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,

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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 49.7% of our outstanding common stock. In addition, our executive 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 5,000,000 shares of our common stock. Following the closing of our initial public offering, Yorktown will own or control approximately 43.2% of our outstanding common stock and our executive officers and their affiliates will beneficially own or control 11.9% 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 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 executive officers and directors may permit them to approve certain matters by stockholder vote and may delay or prevent a change of control of us.

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;

adverse market reaction to any increased indebtedness we incur in the future;

additions or departures of key management personnel;

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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.

The market price of our common stock could be adversely affected by sales of substantial amounts of our common stock in the public markets.

We have recently filed a registration statement to register 5,000,000 shares of our common stock in an underwritten public offering. The sale of the shares of common stock in this public offering or the issuance of a large number of shares of our common stock in connection with future acquisitions, equity financings or otherwise, could cause the market price of our common stock to decline significantly. After the completion of our initial public offering, we will have approximately 37.5 million shares of common stock issued and outstanding, including approximately 20 million shares of our common stock held or controlled by our executive officers and directors which are or will be eligible for sale under Rule 144 after the expiration of the 180-day lock-up period that is applicable to our executive officers, directors, and certain of our stockholders following the completion of our initial public offering. All of the 5,000,000 shares of the common stock sold in our initial public offering will be freely tradable without restriction or further registration under the Securities Act by persons other than our affiliates (within the meaning of Rule 144 under the Securities Act) immediately upon completion of that offering, subject to lock-up agreements that certain of the selling stockholders enter into. Additionally, we may file one or more registration statements with the Securities and Exchange Commission providing for the registration of up to approximately 4.4 million additional shares of our common stock issued or reserved for issuance under our employee plans, all of which will be eligible for sale without further registration under the Securities Act.

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 125,000,000 shares of common stock and 10,000,000 shares of preferred stock with such designations, preferences, and rights as may determined by our board of directors. As of March

31, 2006, 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

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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 Global 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.

Failure by us to achieve and maintain effective internal control over financial reporting in accordance with the rules of the SEC could harm our business and operating results and/or result in a loss of investor confidence in our financial reports, which could have a material adverse effect on our business and stock price.

We are in the process of documenting our internal controls systems to allow management to evaluate and report on, and our independent auditors to audit, our internal controls over financial reporting. Once the documentation is complete, we will be performing the system and process evaluation and testing (and any necessary remediation) required to comply with the management certification and auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act of 2002. We will be required to comply with Section 404 for the year ending December 31, 2007. However, we cannot be certain as to the timing of completion of our evaluation, testing and remediation actions or the impact of the same on our operations. Furthermore, upon completion of this process, we may identify control deficiencies of varying degrees of severity under applicable SEC and Public Company Accounting Oversight Board rules and regulations that remain unremediated. As a public company, we will be required to report, among other things, control deficiencies that constitute a material weakness or changes in internal controls that, or that are reasonably likely to, materially affect internal controls over financial reporting. A material weakness is a significant deficiency or combination of significant deficiencies that results in more than a remote likelihood that a material misstatement of the annual or interim consolidated financial statements will not be prevented or detected. If we fail to implement the requirements of Section 404 in a timely manner, we might be subject to sanctions or investigation by regulatory authorities such as the SEC. In addition, failure to comply with Section 404 or the report by us of a material weakness may cause

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investors to lose confidence in our consolidated financial statements, and our stock price may be adversely affected as a result. If we fail to remedy any material weakness, our consolidated financial statements may be inaccurate, we may face restricted access to the capital markets and our stock price may be adversely affected.

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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. 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 March 31, 2006, on:

- a historical basis; and

- an as adjusted basis to give effect to the issuance and sale by us of 4,850,000 shares of common stock 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.

	March 31, 2006	
	Historical	As Adjusted
	(In thousands)	
Cash and cash equivalents	$ 1,340	$ 1,340
Long-term debt(1)	$ 58,377	$ 9,611
Stockholders equity:		
Common stock, $0.001 par value, 125,000,000 shares authorized; and 32,614,021 shares issued and outstanding, and 37,464,021 shares issued and outstanding, as adjusted(2)	$ 33	$ 38
Preferred stock, $0.001 par value, 10,000,000 shares authorized, none issued		
Additional paid-in capital(3)	133,956	182,717
Accumulated other comprehensive income	31	31
Retained earnings	13,607	13,607
Notes receivable	(413)	(413)
Total stockholders equity	147,214	195,980
Total capitalization	$ 206,931	$ 205,591

(1) Long-term debt decreased by $48.8 million from the application of the proceeds from the sale by us of 4,850,000 shares of common stock in our initial public offering.
(2) 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 within 60 days.
(3) Our additional paid-in capital increased by approximately $48.8 million from the sale by us of 4,850,000 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 selected historical consolidated financial and operating data as of and for the three months ended March 31, 2006 and 2005 and each of the five years ended December 31, 2005. The selected historical consolidated financial and operating data for the three months ended March 31, 2006 and 2005 was derived from our unaudited financial statements included herein. The selected historical consolidated financial and operating data for the three years ended December 31, 2005 are derived from our audited financial statements included herein. The selected 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.

	Three Months Ended March 31,		Year Ended December 31,				
	2006	2005	2005	2004	2003	2002	2001
	(Unaudited)						
	(In thousands, unless otherwise indicated)						
STATEMENT OF OPERATIONS AND COMPREHENSIVE INCOME DATA:							
REVENUES							
Gas sales	$ 12,311	$ 6,369	$ 41,604	$ 19,522	$ 11,700	$ 6,731	$ 11,850
Operating fees and other		138	376	1,402	349	277	205
Total revenues	12,311	6,507	41,980	20,924	12,049	7,008	12,055
EXPENSES							
Lease operating expenses	2,841	2,083	8,687	5,092	1,640	590	542
Compression and transportation expenses	1,076	721	3,332	1,951	993	654	681
Production taxes	269	126	914	473	414	285	560
Depreciation, depletion and amortization	1,834	885	4,867	2,691	2,120	2,151	3,167
Research and development	69	1	609	279	432	168	
General and administrative	1,020	751	3,208	2,513	1,370	1,598	1,206
Impairment of other equipment and other non-current assets					8	108	
Realized losses (gains) on derivative contracts	596	(165)	7,473	815	44		
Unrealized losses (gains) from the change in market value of open derivative contracts	(9,074)	4,839	12,059	(542)	102		
Total operating expenses	(1,369)	9,241	41,149	13,272	7,123	5,554	6,156
Income from operations	13,680	(2,734)	831	7,652	4,926	1,454	5,899
Interest income	11	17	77	70	95	119	291
Interest expense, net of amounts capitalized	(863)	(609)	(3,895)	(986)	(232)	(186)	(151)
Other expenses	(13)		(21)	(4)	(7)	(7)	(3)
Total other income (expense)	(865)	(592)	(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	12,815	(3,226)	(3,008)	6,732	4,782	1,380	6,036
Income tax expense (benefit)	5,652	(1,106)	(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	7,163	(2,220)	(2,015)	4,420	3,131	741	4,884
Minority interest		(507)	(442)	584	571	138	958
Net income (loss) before cumulative effect of change in accounting principle, net of income tax	7,163	(1,713)	(1,573)	3,836	2,560	603	3,926
Cumulative effect of change in accounting principle, net of income tax					19		
Net income (loss)	$ 7,163	$ (1,173)	$ (1,573)	$ 3,836	$ `2,541	$ 603	$ 3,926
Other comprehensive income							
Foreign currency translation adjustment, net of income taxes of $0	25	(4)	54	2			
Comprehensive income (loss)	$ 7,138	$ (1,717)	$ (1,519)	$ 3,838	$ 2,541		