GeoMet, Inc.
Form 424B4
July 28, 2006
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Filed Pursuant to Rule 424(b)(4)
Registration No. 333-134070

Prospectus

5,000,000 Shares

Common Stock

GeoMet, Inc. is offering 5,000,000 shares of common stock. This is our initial public offering, and no public market currently exists for our shares.

Our common stock has been approved for listing on the Nasdaq Global Market under the symbol GMET.

Investing in our common stock involves a high degree of risk. See Risk Factors beginning on page 10.

	Per Share	Total
Offering price	$ 10.00	$ 50,000,000
Discounts and commissions to underwriters	$ 0.70	$ 3,500,000
Offering proceeds to GeoMet, Inc., before expenses	$ 9.30	$ 46,500,000

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved these securities or determined if this prospectus is accurate or complete. Any representation to the contrary is a criminal offense.

We have granted the underwriters the right to purchase up to 750,000 additional shares of common stock on the same terms and conditions as set forth above if the underwriters sell more than 5,000,000 shares of common stock in this offering. The underwriters can exercise this right at any time and from time to time, in whole or in part, within 30 days after the offering. The underwriters expect to deliver the shares of common stock to investors on or about August 2, 2006.

Banc of America Securities LLC

A.G. Edwards **Raymond James**

July 27, 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. Unless otherwise indicated, share numbers in the prospectus assume that the underwriters do not exercise their option to purchase additional shares of common stock. 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 on development expenditures 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

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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 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 have 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 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 16,900 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.

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.

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 approximately $73.0 million was available for borrowing at 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.

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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, 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 us(1)	5,000,000 shares.
Common stock to be outstanding after this offering(1)(2)(3)	37,614,021 shares.
Use of proceeds	We will receive net proceeds from the sale of the shares offered by us, after deducting estimated offering expenses and underwriting discounts and commissions, of approximately $45.6 million. We intend to use our net proceeds from this offering to repay a portion of the outstanding indebtedness under our credit facility. In the event the underwriters exercise their option to purchase additional shares of common stock, we will use the additional net proceeds of approximately $7.0 million (assuming the option is exercised in full) to repay a portion of the outstanding indebtedness under our credit facility.
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.
Proposed Nasdaq symbol	GMET

(1) We have granted the underwriters an option to purchase up to 750,000 additional shares of our common stock if the underwriters sell more than 5,000,000 shares of common stock in this offering. Unless otherwise indicated, share numbers assume that the underwriters do not exercise their option to purchase additional shares of common stock.
(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) Represents 32,614,021 shares outstanding on March 31, 2006, and the 5,000,000 shares to be issued and sold by us in this 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,		Year 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	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
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. 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.

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
- 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.

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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 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 will own approximately 43.1% of our outstanding common stock after the closing of this offering. In addition, our executive officers and their affiliates will beneficially own or control approximately 11.9% of our outstanding common stock following the closing of this offering. 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;

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 registering for resale the 10,250,000 shares of common stock that we sold in our private placement during the first quarter of 2006. The sale of a large number of shares of our common stock pursuant to the resale registration statement, the perception that any such sale might occur, 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 this offering, we will have approximately 37.6 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 this offering. All of the shares of common stock sold in this 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 this offering, subject to the 180-day lock-up period. 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 issuance of such additional shares of common stock may create downward pressure on the trading price of our

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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.

Purchasers of common stock in this offering will experience immediate and substantial dilution of $4.87 per share.

Purchasers of our common stock in this offering will experience an immediate and substantial dilution of $4.87 per share in the as adjusted net tangible book value per share of common stock from the initial public offering price, and our as adjusted net tangible book value as of March 31, 2006 after giving effect to this offering would be $5.13 per share. See Dilution.

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

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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 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 receive net proceeds from this offering of approximately $45.6 million ($52.6 million if the underwriters option to purchase additional shares is exercised in full) after deducting underwriting discounts and commissions and estimated offering expenses of $850,000 payable by us.

We intend to use our net proceeds from this offering to repay a portion of the outstanding indebtedness under our credit facility. In the event the underwriters exercise their option to purchase additional shares, we will use the additional proceeds of approximately $7.0 million (assuming the option is exercised in full) to repay a portion of the outstanding indebtedness under our credit facility. As of July 27, 2006, total borrowings under our credit facility were $77.0 million. Our credit facility has a maturity date in January 2011 and bears interest at a floating rate that averaged 6.685% as of July 27, 2006.

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 5,000,000 shares of common stock in this offering and the application of the net proceeds we receive as described under Use of Proceeds.

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	$ 12,727
Stockholders equity:		
Common stock, $0.001 par value, 125,000,000 shares authorized; and 32,614,021 shares issued and outstanding, and 37,614,021 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	179,601
Accumulated other comprehensive income	31	31
Retained earnings	13,607	13,607
Notes receivable	(413)	(413)
Total stockholders equity	147,214	192,864
Total capitalization	$ 206,931	$ 205,591

(1) Long-term debt decreased by $45.6 million from the application of the proceeds from the sale by us of 5,000,000 shares of common stock in this 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 $45.6 million from the sale by us of 5,000,000 shares of common stock in this offering.

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DILUTION

If you invest in our common stock, your interest will be diluted to the extent of the difference between the public offering price per share and the net tangible book value per share of the common stock after this offering. Our net tangible book value as of March 31, 2006, was $147.2 million, or $4.51 per share of common stock. Net tangible book value per share represents the amount of the total tangible assets less our total liabilities, divided by the number of shares of common stock that are outstanding. After giving effect to the sale by us of 5,000,000 shares of common stock in this offering and after the deduction of underwriting discounts and commissions and estimated offering expenses, the as adjusted net tangible book value at March 31, 2006 would have been $192.9 million, or $5.13 per share. This represents an immediate increase in such net tangible book value of $0.61 per share to existing stockholders and an immediate and substantial dilution of $4.87 per share to new investors purchasing common stock in this offering. The following table illustrates this per share dilution:

Offering price per share		$ 10.00
Net tangible book value per share as of March 31, 2006	$ 4.51	
Increase attributable to new public investors	$ 0.61	
As adjusted net tangible book value per share after this offering		$ 5.13
Dilution in as adjusted net tangible book value per share to new investors		$ 4.87

Assuming the exercise in full of the underwriters option to purchase additional shares, our as adjusted net tangible book value at March 31, 2006 would have been approximately $5.21 per share, representing an immediate increase in the net tangible book value of $0.70 per share to our existing stockholders and an immediate decrease in net tangible book value of $4.79 per share to new investors.

The following table summarizes, on an as adjusted basis, as of March 31, 2006, the difference between the number of shares of common stock purchased from us, the total consideration paid to us and the average price per share paid by existing stockholders and by new investors in this offering, before deducting estimated underwriting discounts and commissions and estimated offering expenses.

	Shares Purchased		Total Consideration		Average Price Per
	Number	Percent	Amount	Percent	Share
	(In thousands, except per share data)				
Existing stockholders	32,614	86.7%	$ 136,947	73.3%	$ 4.20
New investors	5,000	13.3	50,000	26.7	10.00
Total	37,614	100.0%	$ 186,947	100.0%	$ 4.97

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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 (loss) 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	$ (1,713)	$ (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	$ 603	$ 3,926

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SELECTED HISTORICAL CONSOLIDATED FINANCIAL AND OPERATING DATA (continued):

	Three Months Ended March 31,		Year Ended December 31,				
	2006	2005	2005	2004	2003	2002	2001
	(Unaudited)		(In thousands unless otherwise indicated)				
Net income (loss) per common share:							
Basic	$ 0.23	$ (0.07)	$ (0.06)	$ 0.17	$ 0.20	$ 0.08	$ 0.49
Diluted	$ 0.22	$ (0.07)	$ (0.06)	$ 0.17	$ 0.20	$ 0.08	$ 0.49
BALANCE SHEET DATA (at period end):							
Working capital (deficit)	$ (8,384)	$ (6,388)	$ (7,368)	$ (1,251)	$ 5,133	$ 3,940	$ 6,268
Total assets	$ 260,951	$ 159,284	$ 247,909	$ 142,090	$ 81,505	$ 42,261	$ 33,240
Long-term debt	$ 58,377	$ 67,467	$ 99,926	$ 51,513	$ 10,102	$ 6,665	$ 1,242
Stockholders equity	$ 147,214	$ 60,975	$ 95,422	$ 65,692	$ 52,754	$ 22,912	$ 22,310
OTHER DATA:							
Net cash provided by operating activities	$ 10,504	$ 2,696	$ 12,433	$ 10,580	$ 10,801	$ 4,603	$ 8,669
Net cash used in investing activities	$ (13,038)	$ (18,134)	$ (59,661)	$ (66,193)	$ (36,341)	$ (12,773)	$ (5,232)
Net cash provided by (used in) financing activities	$ 3,270	$ 15,948	$ 44,906	$ 50,192	$ 30,534	$ 5,372	$ (2,127)
Capital expenditures	$ 13,327	$ 18,130	$ 59,817	$ 86,189	$ 36,069	$ 12,770	$ 5,117
Net sales volume (Bcf)	1.4	1.0	4.6	3.2	2.5	2.1	2.5
Average natural gas sales price ($ per Mcf)	$ 9.08	$ 6.38	$ 9.06	$ 6.12	$ 4.71	$ 3.16	$ 4.73
Average natural gas sales price ($ per Mcf) realized(1)	$ 8.64	$ 6.56	$ 7.43	$ 5.87	$ 4.69	$ 3.16	$ 4.73
Total production expenses ($ per Mcf)	$ 3.09	$ 2.94	$ 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)	$ 15.5	$ (1.3)	$ 6.1	$ 9.8	$ 6.5	$ 3.5	$ 8.1

(1) Average realized price includes the effects of realized gains or 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 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 future 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, 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.

	Three Months Ended March 31,		Year Ended December 31,				
	2006	2005	2005	2004	2003	2002	2001
	(Unaudited)						

	(In thousands)						
Net income (loss)	$ 7,163	$ (1,713)	$ (1,573)	$ 3,836	$ 2,541	$ 603	$ 3,926
Add: Interest expense (net of amounts capitalized)	863	609	3,895	986	232	186	151
Less: Interest income	(11)	(18)	(77)	(70)	(94)	(119)	(291)
Add (Deduct): Income tax expense (benefit)	5,651	(1,106)	(993)	2,312	1,651	639	1,152
Add: Depreciation, depletion and amortization	1,834	886	4,867	2,691	2,120	2,151	3,167
EBITDA	$ 15,500	$ (1,342)	$ 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.

For the three months ended March 31, 2006, gas production increased by 360.3 MMcf from the comparable period in the prior year to 1.4 Bcf. The increase in production was principally related to the continued development of our Cahaba and Pond Creek fields. In addition, average gas sales prices were $9.08 per Mcf, an increase of $2.70 per Mcf from the comparable period in the prior year.

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 probability of achieving our targeted level of cash flows. As a result of these hedging positions, we had unrealized gains in the amount of $9.1 million for the three months ended March 31, 2006 compared to unrealized losses of $4.8 million in the comparable prior year period.

Our financial results are impacted by many factors such as the price of natural gas, our levels of production, and our ability to market our production. Commodity prices and production volumes are affected by changes in market demand, which is impacted by overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. As a result, we cannot accurately predict future natural gas prices, and therefore, we cannot determine what effect increases or decreases will have on our capital program, production volumes, future revenues and reserves. In addition to production volumes and commodity prices, finding and developing sufficient amounts of natural gas reserves at economical costs are critical to our long-term success.

We believe that our cash flow from operations and other financial resources such as our credit facility and equity offerings will provide us with the ability to fully develop our existing properties and finance our current exploration on unevaluated properties.

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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 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.

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 the use of an option-pricing model that is based on various assumptions and factors including the time value of options, volatility and closing NYMEX market indices.

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

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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 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

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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 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. We believe our methodology and valuations represented the estimated fair value of our common stock at that time.

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;

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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;

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 384.56 at 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; however, for the three months ended March 31, 2006 prices decreased, and we recognized a total gain on derivative contracts in the amount of $8.5 million, consisting of a $0.6 million realized loss and a $9.1 million unrealized gain.

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Producing Field Operations Summary

The table below presents information on gas revenues, sales volumes, production expenses and per Mcf data for the three months ended March 31, 2006 and 2005 and 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.

	Three Months Ended March 31,		Year Ended December 31,		
	2006	2005	2005	2004	2003
	(In thousands except per Mcf)				
Gas sales	$ 12,311	$ 6,369	$ 41,604	$ 19,522	$ 11,700
Lease operating expenses	$ 2,841	$ 2,083	$ 8,687	$ 5,092	$ 1,640
Compression and transportation expenses	1,076	721	3,332	1,951	993
Production taxes	269	126	914	473	414
Total production expenses	$ 4,186	$ 2,930	$ 12,933	$ 7,516	$ 3,047
Net sales volumes (MMcf)	1,356	996	4,594	3,187	2,484
Per Mcf data ($/Mcf):					
Average natural gas sales price	$ 9.08	$ 6.38	$ 9.06	$ 6.12	$ 4.71
Average natural gas sales price realized(1)	$ 8.64	$ 6.56	$ 7.43	$ 5.87	$ 4.69
Lease operating expenses	$ 2.09	$ 2.09	$ 1.89	$ 1.60	$ 0.66
Compression and transportation expenses	$ 0.79	$ 0.72	$ 0.72	$ 0.61	$ 0.40
Production taxes	$ 0.21	$ 0.13	$ 0.20	$ 0.15	$ 0.17
Total production expenses	$ 3.09	$ 2.94	$ 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

Three Months Ended March 31, 2006 compared with Three Months Ended March 31, 2005

The following is a discussion of significant matters affecting the operating and financial results for the three months ended March 31, 2006 compared to the three months ended March 31, 2005.

Selected items presented in our Consolidated Statement of Operations and Comprehensive Income on page F-29 and their percentage changes from the comparable period are presented below.

	Three Months Ended March 31,		
	2006	**2005**	**Change**
	(Unaudited) (In thousands)		
Gas sales	$ 12,311	$ 6,369	93%
Operating fees and other		138	(100)%
Total revenues	$ 12,311	$ 6,507	89%
Lease operating expenses	$ 2,841	$ 2,083	36%
Compression and transportation expenses	1,076	721	49%
Production taxes	269	126	113%
Depreciation, depletion and amortization	1,834	885	107%
Research and development	69	1	680%
General and administrative	1,020	751	36%
Realized losses (gains) on derivative contracts	596	(165)	461%
Unrealized losses (gains) from the change in market value of open derivative contracts	(9,074)	4,839	(288)%
Total operating expenses	$ (1,369)	$ 9,241	(115)%
Interest expense (net of amounts capitalized)	$ (863)	$ (609)	42%
Income (loss) before income taxes and minority interest, net of income tax	$ 12,815	$ (3,326)	485%
Income tax expense (benefit)	5,652	(1,106)	611%
Net income (loss) before minority interest, net of income tax	$ 7,163	$ (2,220)	423%

Gas sales. Gas sales increased by $5.9 million, or 93%, to $12.3 million compared to the prior year quarter. The increase in gas sales was a result of increased production and average gas prices. Production increased 36% while average gas prices, excluding hedging transactions, increased 42%. The $5.9 million increase in gas sales consisted of a $3.6 million increase in prices and a $2.3 million increase in production. The increase in production was principally attributable to our Cahaba and Pond Creek development activities.

Lease operating expenses. Lease operating expenses increased by $0.758 million, or 36% to $2.8 million. The increase in lease operating expenses was primarily a result of increased production as the unit costs per Mcf remained fairly flat.

Compression and transportation expenses. Compression and transportation expenses increased by $0.355 million, or 49% to $1.1 million. The $0.355 million increase in compression and transportation expenses consisted of a $0.261 million increase in production and a $0.094 million increase in costs. The increase in cost per Mcf was a result of additional compressors and increases in transportation fees to support the increase in production levels.

Production taxes. Production taxes increased by $0.143 million, or 114%, to $0.269 million. The production taxes increase of $0.143 million consisted of a $0.097 million increase in costs and a $0.046 million increase in production. The increase in production taxes was a result of increased production and the increase in costs was a result of reduced tax exemptions at certain fields.

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Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $0.949 million, or 107%, to $1.8 million. The depreciation, depletion and amortization increase of $0.949 million consisted of a $0.629 million increase in depletion rate and a $0.320 million increase in production. The increase in the depletion rate was primarily due to $48.0 million added to 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, a downward reserve revisions at Cahaba and increased drilling and completion costs.

General and administrative. General and administrative expenses increased by $0.269 million or, 36%, to $1.0 million. The increase in general and administrative expenses was a result of increases in employee expenses (13%), professional services (58%), director expenses (12%), office expenses and business taxes (34%). This increase was partially offset by increased capitalized general and administrative expenses (46%) and field and operating overhead recoveries (54%). The largest increase was in professional services that resulted from the increased audit, tax and legal services. The increase in general and administrative expenses was a result of expanding the overhead structure to support our growth and the increased costs of preparing to be a public company.

Realized losses on derivative contracts. Realized losses on derivative contracts increased by $0.761 million to $0.596 million compared to a gain of $0.165 million in the prior corresponding period. Realized losses represent net cash flow settlements paid to the counterparty while realized gains represent net cash flow settlement paid to us from the counterparty. Realized losses occur when commodity gas prices or the derivative index price exceeds the derivative ceiling price. Conversely, realized gains occur when commodity gas prices go below the derivative floor price.

Unrealized losses (gains) from the change in market value of open derivative contracts. Unrealized losses (gains) from the change in market value of open derivative contracts generated a $9.1 million gain as compared to a $5.0 million loss in the comparable period in 2005. Unrealized losses and gains are non-cash transactions that occur when the corresponding asset or liability derivative contracts are marked to market at the end of each reporting period. Unrealized gains are recognized when the fair values of derivative assets increase or the fair value of derivative liabilities decrease. Unrealized losses are recognized when the fair values of derivative assets decrease or the fair value of derivative liabilities increase. The $9.1 million gain was a result of decreased commodity gas prices.

Interest expense (net of amounts capitalized). Interest expense (net of amounts capitalized) increased by $0.254 million, or 42%, to $0.863 million. The increase was primarily due to higher outstanding bank balances and higher interest rates. The increase in interest expense was partially offset by capitalizing the interest expense to our gas properties.

Income tax expense (benefit). Income tax expense (benefit) resulted in expense of $5.7 million in the first quarter of 2006 compared to a benefit of $1.1 million in the comparable prior period in 2005. The increase in income tax expense in the current quarter was due to (1) the pretax income position versus a pretax loss position in the comparable prior period and (2) an increase in the effective tax rate for the current quarter to 44% from 33.2% in the comparable prior period as a result of certain state taxes not previously included in prior periods and the related cumulative non-cash adjustment of $0.406 million. Excluding the state tax revision, the revised estimated effective tax rate for the year is expected to be approximately 40.1%.

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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,		Percentage
	2005	2004	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.

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 as a result of 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:

	Year 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 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 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 $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

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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

Cash flow from operations for the three months ending March 31, 2006 and 2005 were $10.5 million and $2.7 million, respectively. Cash flow from operations for the three months ended March 31, 2006 of $10.5 combined together with net proceeds of the private offering of $27.6 million and proceeds from the collection of notes receivable of $17.2 were sufficient to fund our capital expenditures of $13.4 million and the repayment of our revolving credit facility and other debt of $41.5 million.

As of March 31, 2006 and December 31, 2005, we had a working capital deficit of approximately $8.4 million and $7.1 million, respectively. The increase in the working capital deficit was primarily a result of decreased accounts receivable and increased accounts payable. This increase in the deficit was partially offset by increased cash and cash equivalents and decreased net derivative liabilities. At March 31, 2006, we had adequate cash flows from operating activities and adequate credit availability to fund our working capital deficits.

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 this offering to fund our 2006 capital expenditures and other working capital needs.

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 indicated above, we have elected not to designate any of our current derivative contracts as accounting hedges under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, and accordingly, accounted for our derivative contracts using mark-to-market accounting. During the three months ended March 31, 2006, we recognized gains on derivative contracts of $8.478 million, which included realized losses of $0.596 million. During the three months ended March 31, 2005, we recognized losses on derivative contracts of $4.674 million, which included realized gains of $0.165 million.

As of July 27, 2006, the following natural gas derivative contracts were outstanding with prices expressed in dollars per million British thermal units ($/MMBtu) and notional volumes in million British thermal units. The daily volumes that we hedge are equal during each production period. For our natural gas derivative contracts, summer months apply to April through October and winter months apply to November through March of each year.

Instrument Type	Production Period	Volumes (MMBtu)	Weighted Average Floor Prices ($/MMBtu)		Weighted Average Cap Prices ($/MMBtu)
Collars (3 way)	Summer 2006	2,568,000	$ 5.88	$7.00	$ 8.49

Collars (3 way)	Winter 2006/2007	1,510,000	$	6.70	$8.20	$	11.02
Collars (3 way)	Summer 2007	1,712,000	$	5.75	$7.38	$	10.50
Collars (3 way)	Winter 2007/2008	1,216,000	$	6.00	$9.00	$	14.80
Collars (3 way)	Summer 2008	1,712,000	$	5.00	$7.00	$	10.50

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At March 31, 2006 and at December 31, 2005, the fair values of open derivative contracts were liabilities of approximately $2.5 million and $11.5 million, respectively.

Sensitivity analyses of the incremental effects on pre-tax gain for the three months ended March 31, 2006 of a hypothetical 10% and 25% change in natural gas prices for outstanding hedge contracts as of March 31, 2006 are provided in the following table:

	Incremental (Increase)/ Decrease in pre-tax gain assuming a hypothetical price increase and decrease of(1):	
	10%	25%
	(In thousands)	
Price increase	$ (2,315)	$ (6,707)
Price decrease	$ 1,910	$ 4,409

(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

	Year 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

In June 2006, we entered into a $180 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 $150 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.

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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 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 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.

At March 31, 2006, $57.5 million was outstanding under our credit facility. Interest on the borrowings averaged 5.775% per annum. 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 outstanding under our credit facility at March 31, 2006, a 1% change in market interest rates would have increased interest expense and negatively impacted our annual cash flows by approximately $575,000.

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

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.

(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%.

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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 No. 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 SFAS 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 FASB issued Interpretation 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 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

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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.

In February 2006, the FASB issued SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments an amendment of FASB Statements No. 133 and 140*. SFAS No. 155 addresses the following: a) permits fair value re-measurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation; b) clarifies which interest-only strips and principal-only strips are not subject to the requirements of Statement 133; c) establishes a requirement to evaluate interests in securitized financial assets to identify interests that are freestanding derivatives or that are hybrid financial instruments that contain an embedded derivative requiring bifurcation; d) clarifies that concentrations of credit risk in the form of subordination are not embedded derivatives; and e) amends Statement 140 to eliminate the prohibition on a qualifying special-purpose entity from holding a derivative financial instrument that pertains to a beneficial interest other than another derivative financial instrument. SFAS No. 155 is effective for all financial instruments acquired or issued after the beginning of an entity s first fiscal year that begins after September 15, 2006. The Company is currently evaluating the requirements of SFAS No. 155, but does not expect that the adoption of this pronouncement will have a material effect on its financial statements.

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 Resources Price Risk Management Activities and Liquidity and Capital Resources 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.

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. 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 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 28 for additional information regarding PV-10. Our estimated proved reserves 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 on development expenditures 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. As of December 31, 2005, we had 132 net productive wells in the Gurnee field. Net daily sales of gas averaged approximately 5,200 Mcf for the month of May 2006. At December 31, 2005, our undeveloped CBM acreage in the Cahaba Basin contained 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 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 intend to drill at least 75 wells annually in the Cahaba Basin over the next five years.

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 31 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.

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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.

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 are re-activating an additional 5.6 miles of existing 12-inch steel pipeline and adding 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 December 31, 2005, we had 156 net productive wells in the Pond Creek field. Net daily sales of gas averaged approximately 10,000 Mcf for the month of May 2006. As of December 31, 2005, our undeveloped CBM acreage in the Pond Creek field contained 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. As of March 31, 2006, we had spent $3.7 million of this budget and drilled nine wells. We intend to drill at least 40 wells annually in the Pond Creek field over the next five years.

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 Appalachian Basin 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 from the Pond Creek field 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 12-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. The construction of our new 12-mile pipeline is presently subject to a dispute regarding the right to use the surface of certain acreage. Additional information regarding this dispute can be found below under Legal Proceedings CNX Surface Use Dispute. 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.

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In addition to our operations in the Pond Creek field, we also have the rights to approximately 17,000 acres in the Lasher prospect located north of the Pond Creek field in the Appalachian Basin. We have drilled two test wells in that area and four core holes.

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. Multiple, mostly thin, coal seams exist at depths from 1,000 to 3,000 feet. At these depths, coals 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 drilled and completed two production test wells and have recompleted a third production test well and a water disposal well. We are currently conducting testing operations on these wells. In 2006, we intend to spend approximately $6.0 million of our capital expenditure budget to evaluate and explore our Peace River acreage.

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.

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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, 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 Developed Non-Producing**	**Proved Undeveloped**	**Total Proved**	**PV-10**
	(MMcf)	**(MMcf)**	**(MMcf)**	**(MMcf)**	**(In million)**
Appalachia:					
Pond Creek field	78,256	1,608	34,594	114,458	$ 366,265
Alabama:					
Gurnee field	88,787	23,730	32,545	145,062	496,624
White Oak Creek field	2,721	37	233	2,991	17,266
Total	169,764	25,375	67,372	262,511	$ 880,155

PV-10, a non-GAAP measure, is our estimated present value of future net revenues from estimated proved reserves before income taxes. We believe PV-10 to be an important measure for evaluating the relative significance of our CBM gas properties and that PV-10 is widely used by professional analysts and investors in evaluating gas companies. Because many factors that are unique to each individual company impact the amount of future income taxes to be paid, the use of a pre-tax measure provides greater comparability of assets when evaluating companies. We believe that most other companies in the oil and gas industry calculate PV-10 on the same basis. Management also uses PV-10 in evaluating acquisition candidates. PV-10 only differs from the

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standardized measure of discounted future net cash flows (SMOG), as calculated and presented in accordance with SFAS No. 69, in that SMOG takes into account the present value of income taxes related to our net cash flows. See Selected Historical Consolidated Financial and Operating Data Reconciliation of Non-GAAP Financial Measures.

CBM-producing natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Therefore, without reserve additions in excess of production through successful exploration and development activities or acquisitions, our reserves and production, after an initial period of incline, are expected to decline. This decline rate, however, is slower than what is generally experienced with non-CBM wells. See Risk Factors and the notes to our consolidated financial statements included elsewhere in this prospectus for a discussion of the risks inherent in CBM gas estimates and for certain additional information concerning the estimated proved reserves.

The weighted average price of gas at December 31, 2005 used to estimate proved reserves and future net revenue was $9.66 per Mcf and was calculated using the Henry Hub cash price at December 31, 2005, of $9.52 per MMBtu of gas, adjusted for our price differentials but excluding the effects of hedging.

Historical Finding and Development Costs

For the three years ended December 31, 2005, our finding and development costs have averaged $0.95 per Mcf. The cost of finding and developing reserves is expressed in dollars per Mcf and is calculated for the three year time period by taking the sum of the cost incurred for exploration, development and acquisition, including future development costs attributable to proved undeveloped reserves, adjusted for the change for the period in the balance of unevaluated gas properties not subject to amortization and dividing such amount by the total proved reserve additions. Estimated future development costs at December 31, 2005 totaled $76.3 million. Management believes that this information is useful to an investor in evaluating GeoMet because it measures the efficiency of a company in adding proved reserves as compared to others in the industry. The cost and reserve information is derived directly from line items disclosed in the schedule of Capitalized Cost, Natural Gas Reserves and the Standardized Measure, which are all required to be disclosed by SFAS 69.

The proved reserve additions, approximately 67% of which are proved developed, are primarily attributable to the development of the Pond Creek and Gurnee fields and the Pond Creek Acquisition. Changes in commodity prices, operating costs and other factors also have an effect on the proved reserve additions. We have not quantified the proved reserve additions that are attributable to factors that did not require the expenditure of additional costs. We have a large property position, consisting of over 255,000 net acres of CBM exploration and development rights, including almost 77,000 net undeveloped acres in our two development areas, with 586 additional drilling locations. We expect that exploration and development activities on these properties, not acquisitions of proved reserves from third parties, will be the principal source of our future proved reserve additions. Nonetheless, our historical finding and development costs may not be indicative of those costs in the future, as exploring for and developing CBM involves a variety of risks, and we are unable to predict the amount or timing of future proved reserve additions or the costs that we may incur in connection with any such reserve additions. There is no accepted standard of computing finding and development costs and as a result, finding and development costs are reported in many different ways by companies that compete with us and in certain cases not reported at all.

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Production and Operating Statistics

The following table presents certain information with respect to our production and operating data for the periods presented.

	Year Ended December 31,		
	2005	2004	2003
Gas:			
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 operations 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
Depreciation, depletion & amortization (excluding impairment)	$ 1.06	$ 0.84	$ 0.85
Research and development	$ 0.13	$ 0.09	$ 0.17
General and administrative	$ 0.70	$ 0.79	$ 0.55

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

Productive Wells and Acreage

The following table sets forth our interest in undeveloped acreage, developed acreage and productive wells in which we own a working interest as of December 31, 2005. Gross represents the total number of acres or wells in which we own a working interest. Net represents our proportionate working interest resulting from our ownership in the gross acres or wells. Productive wells are wells in which we have a working interest and that are producing and wells capable of producing natural gas.

	Productive Wells(1)		Developed Acres		Undeveloped Acres	
Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Appalachian Basin	163	163	11,599	11,599	44,344	44,017
Cahaba Basin	132	132	10,120	10,120	31,646	31,646
North Central Louisiana	17	17			122,612	119,244
British Columbia	2	1			33,000	16,500
Piceance Basin					17,000	16,949
Other (United States)					5,028	4,790
Total	314	313	21,719	21,719	253,630	233,146

(1) Excludes seven gross/net wells pending completion at December 31, 2005.

Drilling Activity

The following table sets forth the number of completed gross exploratory and gross development wells drilled in the United States and Canada that we participated in for each of the last three fiscal years. The number of wells drilled refers to the number of wells commenced at any time during the respective year. Productive wells are producing wells and wells capable of production. At December 31, 2005, we were in the process of completing seven gross wells (seven net).

	Exploratory			Development		
Well Activity (Gross) United States	**Productive**	**Dry**	**Total**	**Productive**	**Dry**	**Total**
Year ended December 31, 2005	4	3	7	93		93
Year ended December 31, 2004	10	1	11	85		85
Year ended December 31, 2003	16	1	17	133		133

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Well Activity (Gross) Canada	Exploratory			Development		
	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2005	2		2			

The following table sets forth, for each of the last three fiscal years, the number of completed net exploratory and net development wells drilled by us based on our proportionate working interest in such wells.

Well Activity (Net) United States	Exploratory			Development		
	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2005	4.0	3.0	7.0	93.0		93.0
Year ended December 31, 2004	10.0	1.0	11.0	81.8		81.8
Year ended December 31, 2003	15.0	1.0	16.0	47.7		47.7

Well Activity (Net) Canada	Exploratory			Development		
	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2005	1.0		1.0			

Title to Properties

Our properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. We do not believe that any of these burdens materially interfere with our use of the properties in the operation of our business.

We believe that we have generally satisfactory title to or rights in all of our producing properties. As is customary in the oil and gas industry, we make minimal investigation of title at the time we acquire undeveloped properties. We make title investigations and receive title opinions of local counsel only before we commence drilling operations. We believe that we have satisfactory title to all of our other assets. Although title to our properties is subject to encumbrances in certain cases, we believe that none of these burdens will materially detract from the value of our properties or from our interest therein or will materially interfere with our use in the operation of our business.

Marketing and Customers

We market all of our gas through Shamrock Energy LLC, a wholly owned subsidiary of Optigas, Inc., under a natural gas purchase contract that may be terminated by either party upon 90 days notice after February 2006. The contract calls for Shamrock to purchase and us to sell gas from properties covered by the contract, which includes all of our major properties. Shamrock provides several related services including nominations, gas control, gas balancing, transportation and exchange, market and transportation intelligence and other advisory and agency services. We receive the weighted average resale price for the gas less a fee for Shamrock s services ranging from $0.03 to $0.045 per MMBtu purchased. Proceeds from the sale of the gas are deposited into and disbursed from a trust account for our benefit and the obligations of Shamrock are guaranteed by Optigas. The parties have agreed to amend the contract to make certain technical changes including changes in the payment and reporting terms and to provide that the contract is cancelable by either party on 90 days notice.

On June 14, 2006, we entered into an option agreement with Jon M. Gipson, the president of Shamrock, pursuant to which we have the right, from August 1, 2006 to January 31, 2007, to acquire all of the outstanding equity interests and assets of Shamrock once Mr. Gipson acquires the outstanding equity interests of Shamrock pursuant to an agreement Mr. Gipson has entered into with Optigas. In exchange for this option, we agreed (i) to extend our gas marketing agreement with Shamrock for a term ending no earlier than January 31, 2007, (ii) to advance, on or before August 1, 2006, $90,000 to Shamrock for working capital purposes during the option period, (iii) to provide any guaranties on behalf of Shamrock for transactions that Shamrock enters into during the option period that require such guaranties, up to an aggregate of $1,500,000, and (iv) to advance up to an

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additional $50,000 to Shamrock as may be required to cover certain expenses of Shamrock prior to January 31, 2007, the date on which our option to purchase Shamrock expires.

In the event that we exercise the option, we will be obligated to provide Mr. Gipson an at-will employment position with us at an annual salary of not less than $130,000, and we will also pay Mr. Gipson an amount equal to 50% of the net profits generated by Shamrock from August 1, 2006 through the date that we elect to exercise the option, up to January 31, 2007. No additional consideration is due upon our exercise of this option. In the event we do not exercise the option by January 31, 2007 and Mr. Gipson continues to operate Shamrock after the end of the option period, Shamrock will retain 100% of the net profits generated during the option period, all guaranties that we have entered into on behalf of Shamrock will terminate on January 31, 2007, and Shamrock will repay us all funds that we advanced to Shamrock in equal amounts, without interest, over an 18-month period. If we do not exercise the option by January 31, 2007 and Mr. Gipson elects not to continue to operate Shamrock, Mr. Gipson will wind up the affairs of Shamrock within 90 days after the end of the option period, and we will receive 100% of the net profits from the operations during the wind-up period and the proceeds from the liquidation of Shamrock s assets until we have been repaid all funds that we advanced to Shamrock and all guaranties that we entered into on behalf of Shamrock have been terminated and released.

Competition

Our operations primarily compete regionally in the northeastern and southeastern United States. Competition throughout the United States is regionalized. We believe that the gas market is highly fragmented and not dominated by any single producer. We believe that several of our competitors have devoted far greater resources than we have to gas exploration and development. We believe that competition within our market is based primarily on price and the proximity of gas fields to customers.

Regulation

Regulation by the FERC of Interstate Natural Gas Pipelines. We do not own any interstate natural gas pipelines, so the Federal Energy Regulatory Commission, or the FERC, does not directly regulate any of our operations. However, the FERC s regulation influences certain aspects of our business and the market for our products. In general, the FERC has authority over natural gas companies that provide natural gas pipeline transportation services in interstate commerce, and its authority to regulate those services includes:

- the certification and construction of new facilities;
- the extension or abandonment of services and facilities;
- the maintenance of accounts and records;
- the acquisition and disposition of facilities;
- the initiation and discontinuation of services; and

various other matters.

In recent years, the FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, we cannot assure you that the FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity.

Intrastate Regulation of Natural Gas Transportation Pipelines. We do not own any pipelines that provide intrastate natural gas transportation, so state regulation of pipeline transportation does not directly affect our operations. As with FERC regulation described above, however, state regulation of pipeline transportation may influence certain aspects of our business and the market for our products.

Gathering Pipeline Regulation. Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of the FERC. We own an intrastate natural gas pipeline that we believe would meet the traditional

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tests the FERC has used to establish a pipeline s status as a gatherer not subject to the FERC jurisdiction. However, the distinction between the FERC-regulated transmission services and federally unregulated gathering services is the subject of regular litigation, so, in such a circumstance, the classification and regulation of some of our gathering facilities may be subject to change based on future determinations by the FERC and the courts.

In the states in which we operate, regulation of intrastate gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirement and complaint based rate regulation. For example, we are subject to state ratable take and common purchaser statutes. Ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. In certain circumstances, such laws will apply even to gatherers like us that do not provide third party, fee-based gathering service and may require us to provide such third party service at a regulated rate. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas.

Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels now that the FERC has taken a less stringent approach to regulation of the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. Our gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services. Our gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement, and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Sales of Natural Gas. The price at which we sell natural gas currently is not subject to federal regulation and, for the most part, is not subject to state regulation. Our sales of natural gas are affected by the availability, terms, and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. The FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to the FERC s jurisdiction. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry, and these initiatives generally reflect more light handed regulation. We cannot predict the ultimate impact of these regulatory changes to our natural gas marketing operations, and we note that some of the FERC s more recent proposals may adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any such FERC action materially differently than other sellers of natural gas with whom we compete.

Environmental Regulations

Our coalbed methane exploration and production operations are subject to significant federal, state, and local environmental laws and regulations governing environmental protection as well as the discharge of substances into the environment. These laws and regulations may restrict the types, quantities, and concentrations of various substances that can be released into the environment as a result of natural gas and oil drilling, production, and processing activities; suspend, limit or prohibit construction, drilling and other activities in certain lands lying within wilderness, wetlands and other protected areas; require remedial measures to mitigate pollution from historical and on-going operations such as the use of pits and plugging of abandoned wells; and restrict injection of liquids into subsurface strata that may contaminate groundwater. Governmental authorities

have the power to enforce compliance with their laws, regulations and permits, and violations are subject to injunction, as well as administrative, civil and even criminal penalties. The effects of these laws and regulations, as well as other laws or regulations that are adopted in the future, could have a material adverse impact on our operations.

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

The following is a summary of some of the existing environmental laws, rules and regulations to which our operations in the United States are subject. Our operations in Canada are subject to similar Canadian requirements.

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

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

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

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

Our CBM exploration and production operations produce substantial volumes of water that must be disposed of in compliance with requirements of the CWA, Safe Drinking Water Act, or SDWA, or an equivalent state regulatory program. This produced water is disposed of by re-injection into the subsurface through disposal wells, discharge to surface streams, or in evaporation ponds. Discharge of produced water to surface streams and other bodies of water must be authorized in advance pursuant to permits issued under the CWA, and disposal of produced water in underground injection wells must be authorized in advance pursuant to permits issued under the SDWA. To date, we believe that all necessary surface discharge or disposal well permits have been obtained and that the produced water has been disposed in substantial compliance with such permits and applicable laws.

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

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

In addition, our operations may in the future be subject to the regulation of greenhouse gas emissions. Numerous countries, including Canada but not the United States, are participants in the Kyoto Protocol to the United Nations Framework Convention on Climate Change. Participating countries are required to implement national programs to reduce emissions of certain gases, generally referred to as greenhouse gases, that are suspected of contributed to global warming. Although the United States is not participating in the Protocol, there has been support in various regions of the country for legislation that requires reductions in greenhouse gas emissions, and some states have already adopted legislation addressing greenhouse gas emissions from certain greenhouse gas emission sources, primarily power plants. The oil and gas exploration and production industry is a direct source of certain greenhouse gas emissions, namely carbon dioxide and methane, and future restrictions on such emissions could impact our future operations. Our operations in the United States currently are not adversely impacted by current state and local climate change initiatives. Our Canadian operations are subject to the Protocol, but implementation of the Protocol s greenhouse gas emission reduction requirements in British Columbia are not presently expected to have a significant adverse effect on our operations. However, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions may impact our business.

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Employees

At December 31, 2005, we had 63 full-time employees. None of our employees are represented by a labor union or covered by any collective bargaining agreement. We believe that our relations with our employees are satisfactory.

Legal Proceedings

From time to time we are a party to various legal proceedings arising in the ordinary course of business. While the outcome of lawsuits cannot be predicted with certainty, management does not expect these matters to have a materially adverse effect on our financial condition, results of operations or cash flows.

El Paso Overriding Royalty Interest Dispute

We filed a claim in the 116th District Court of Dallas County, Texas on June 9, 2004 against El Paso Production Company, CMV Joint Venture and CDX Minerals, LLC seeking a declaratory judgment of our rights under a joint operating agreement covering certain properties in White Oak Creek. We had previously entered into an agreement to sell our interest to CDX, subject to a preferential right to purchase held by El Paso, which El Paso subsequently exercised. A dispute arose as to whether the preferential right granted under the agreement applied to overriding royalty interests and other related interests. We have asserted that the preferential right to purchase does not include overriding royalty interests and that we are entitled to retain all overriding royalty interests we possess under the agreement. The trial court rendered judgment in our favor, and El Paso has appealed the decision of the trial court. While we believe that we are entitled to retain these interests, a judgment against us would result in our being required to sell the overriding royalty interest to El Paso for a price of approximately $10.5 million; however, this amount would be reduced by any proceeds we have received from production since the effective date of the sale.

CNX Surface Use Dispute

We and Pocahontas Mining Limited Liability Company (PMC) filed a claim on May 26, 2006 in the Circuit Court of Buchanan County, Virginia against CNX Gas Company LLC (CNX) seeking a temporary and permanent injunction as well as a declaration of our rights under a right-of-way agreement that we entered into with PMC, the surface owner. We are in the process of constructing a 12-mile pipeline, a portion of which traverses this right-of-way to connect with and transport our gas to the Jewell Ridge Pipeline. CNX has claimed that it has the exclusive right to transport gas across the acreage in question and that our right-of-way is invalid. CNX has gated certain access roads to the acreage and requested that we remove our contractor s equipment from the property. The Circuit Court of Buchanan County, Virginia 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.

We believe that our right-of-way agreement is valid and enforceable and that we will prevail in our lawsuit; however, 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 our gas from the

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Pond Creek field to market for an extended period of time. If we are unable to deliver our gas from the Pond Creek field to market for a prolonged period of time, our financial position, results of operations and cash flow will be materially adversely affected.

Insurance Matters

As is common in the gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because premium costs are considered prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our financial position, results of operations and cash flows.

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MANAGEMENT

Executive Officers and Directors

The following discussion sets forth the names and ages of our executive officers and the names and ages of the individuals that serve on our board of directors. Our executive officers are appointed by our board of directors and shall serve until the expiration of their contracts, their death, resignation, or removal by our board of directors. Our directors serve one year terms or until their successors are elected and qualified or until their death, resignation or removal in the manner provided in our bylaws. The present term of each director will expire at the next annual meeting of our stockholders.

Name	Age	Position with Company
J. Darby Seré	58	Chairman of the Board, President, and Chief Executive Officer
William C. Rankin	56	Executive Vice President and Chief Financial Officer
Philip G. Malone	58	Senior Vice President Exploration and Director
Brett S. Camp	47	Senior Vice President Operations
J. Hord Armstrong, III	65	Director
James C. Crain	57	Director
Stanley L. Graves	61	Director
Charles D. Haynes	66	Director
W. Howard Keenan, Jr.	55	Director

J. Darby Seré, *Chairman of the Board, President, and Chief Executive Officer.* Since 2000, Mr. Seré has served as a Director, President and Chief Executive Officer of GeoMet, Inc. Mr. Seré was elected Chairman of the Board in January 2006. Mr. Seré has over 35 years of experience in the oil and gas business, including 17 years as Chief Executive Officer of two publicly held exploration and production companies. Mr. Seré served as President, Chief Executive Officer, and a Director of Bellwether Exploration Company from 1988-1999, where he also served as Chairman of the Board from 1997-1999, and President, Chief Executive Officer and Director of Bayou Resources, Inc. from 1982-1987. Mr. Seré was Manager of Acquisitions, Vice President Acquisitions and Engineering and Executive Vice President of Howell Corporation / Howell Petroleum Corporation from 1977-1981. Mr. Seré began his career as a staff reservoir engineer for Chevron Oil Co. in 1970. Mr. Seré currently serves as a director of Gateway Energy Corporation, a publicly held gas gathering, transportation and distribution company. Mr. Seré is a registered professional engineer and holds a Bachelors degree in Petroleum Engineering from Louisiana State University and a Masters of Business Administration from Harvard University.

William C. Rankin, *Executive Vice President and Chief Financial Officer.* Since 2000, Mr. Rankin has served as Executive Vice President and Chief Financial Officer of GeoMet, Inc. Mr. Rankin has 35 years experience as an accountant and financial manager, including 29 years as a financial officer with both publicly and privately owned energy companies. He began his career as an auditor with Deloitte & Touche from 1971-1975. He served as Director of Internal Audit of Kerr-McGee Corporation from 1975-1977, Controller of Cotton Petroleum Corporation from 1977-1980 and Executive Vice President and Chief Financial Officer for Cayman Resources Corporation from 1980-1985. Mr. Rankin joined Hadson Corporation in 1985 as Vice President and Controller, became Vice President and Treasurer in 1988 and last served as Sr. Vice President and Chief Financial Officer of Hadson Resources Corporation from 1989-1993. In 1994 he became Sr. Vice President and Chief Financial Officer of Contour Energy Company (and its predecessors) where he served until 1997. In 1997, he became Sr. Vice President of Bellwether Exploration Company. Mr. Rankin is a Certified Public Accountant and holds a Bachelors degree in Accounting from the University of Arkansas.

Philip G. Malone, *Senior Vice President Exploration and Director.* Since 2000, Mr. Malone has served as our Vice President Exploration. Mr. Malone has 31 years experience as a professional geologist; one year at the Geological Survey of Alabama, ten years at USX Corporation and 20 years at GeoMet, where he participated in founding the company in 1985. From 1976 to 1985, he was a geologist with USX Corporation and served as chief geologist for the last three years of his tenure with responsibility for supervising exploration and development work related to coal and coalbed methane for USX Southern District. He has authored and co-authored numerous technical papers and is a recognized speaker worldwide on CBM topics. Mr. Malone holds a Bachelors degree in Geology from the University of Alabama.

Brett S. Camp, *Senior Vice President Operations*. Since 2000, Mr. Camp has been our Vice President-Operations. Mr. Camp has 25 years experience as a professional geologist; four years at USX Corporation and 20 years at GeoMet, where he participated in founding the company in 1985. Mr. Camp holds a Bachelors degree in Geology from Eastern Illinois University.

J. Hord Armstrong, III, *Director*. Mr. Armstrong was appointed to our board of directors in January 2006. Mr. Armstrong has over 30 years of financial and operational experience in varied industries. Mr. Armstrong founded D&K Healthcare Resources, Inc. in 1987, and served as its Chairman and Chief Executive Officer until October 2005. From 1977 to 1987, Mr. Armstrong was with Arch Coal Inc. last serving as its Chief Financial Officer. Mr. Armstrong was First Vice President with White Weld & Company from 1968 to 1977. Mr. Armstrong served for ten years as a member of the Board of Trustees of the St. Louis College of Pharmacy and has served as a director of Jones Pharma Incorporated. Mr. Armstrong formerly served as Chairman of the Board of Trustees of the Pilot Fund, a registered investment company, and also formerly served as a Director of BHA, Inc., based in Kansas City, Missouri. Mr. Armstrong graduated from Williams College in 1963, and attended the New York University School of Business in 1965 and 1966.

James C. Crain, *Director*. Mr. Crain was appointed to our board of directors in January 2006. Mr. Crain has been involved in the energy industry for over 30 years, both as an attorney and as an executive officer. Since 1984, Mr. Crain has held officer positions with Marsh Operating Company, including Vice President of Land and Legal, Executive Vice President, and his current position, President, which he has held since 1989. In addition, since 1997, Mr. Crain has acted as the general partner of Valmora Partners, L.P., which invests in various oil and gas businesses. Prior to joining Marsh in 1984, Mr. Crain was a Partner in the law firm of Jenkens & Gilchrist, where he was the head of the Energy Section. Mr. Crain currently serves on the board of directors of Crosstex Energy, L.P., a Delaware limited partnership that is publicly traded on the Nasdaq Global Market. Mr. Crain holds a Bachelors degree in Accounting, a Masters of Professional Accounting in Taxation and a Juris Doctorate degree, all from the University of Texas.

Stanley L. Graves, *Director*. Mr. Graves was appointed to our board of directors in January 2006. Mr. Graves has over 37 years of experience in the oil and gas business. He currently serves as Chairman of the Board of Graves Service Company, Inc., as well as President of Graco Resources, Inc. From 1997-2002, Mr. Graves was the President of U.S. Clay, L.P., which mined and processed bentonite. Prior to his time at U.S Clay, L.P., Mr. Graves served as Vice President Business Development for Ultimate Abrasive Systems, Inc., as President of Eldridge Gathering System Inc., and as Vice President of Energen Corp., the largest CBM producer in Alabama. Mr. Graves currently serves on the board of directors of CapitalSouth Bancorp, a publicly traded bank holding corporation. Mr. Graves holds a Bachelors degree in Engineering from Auburn University.

Charles D. Haynes, *Director*. Dr. Haynes was appointed to our board of directors in January 2006. Dr. Haynes has over 43 years in the energy profession as an academic, researcher, and executive. He retired from The University of Alabama in May 2005, having held faculty and administrative positions since 1991. From 1977 to 1990, he was a senior executive officer and director of Belden & Blake Corporation. He is a licensed professional engineer in Alabama and currently serves as Chair of the Alabama Board of Licensure for Engineers and Land Surveyors. He holds Bachelors, Masters, and Doctorate degrees from The University of Alabama, Pennsylvania State University, and the University of Texas, respectively.

W. Howard Keenan, Jr., *Director*. Mr. Keenan has served on our board of directors since December 2000. Mr. Keenan has over 30 years of experience in the financial and energy businesses. Since 1997, he has been a Member of Yorktown Partners LLC, a private equity investment manager focused on the energy industry. From 1975 to 1997, he was in the Corporate Finance Department of Dillon, Read & Co. Inc. and active in the private

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equity and energy areas including the founding of the first Yorktown Fund in 1991. He is or has served as a director of multiple Yorktown portfolio companies. Mr. Keenan holds a Bachelors degree from Harvard College and a Masters of Business Administration from Harvard University.

Board of Directors; Committees of the Board

Our board of directors is comprised of seven members, consisting of J. Darby Seré, Philip G. Malone, J. Hord Armstrong, III, James C. Crain, Stanley L. Graves, Charles D. Haynes, and W. Howard Keenan, Jr. We expect that Messrs. Armstrong, Crain, Graves, and Haynes, being a majority of our board, will qualify as independent directors as such term is defined by the SEC and the exchange on which our securities will be traded. We have a compensation committee, an audit committee, and a nominating, corporate governance and ethics committee, which are each composed of independent directors. We also have an executive committee that has three members, one of whom is an independent director.

Director Compensation

Each of our independent directors receives an annual retainer of $20,000 and an annual grant of 2,000 shares of non-qualified stock options. Our independent directors also receive $1,500 for each board meeting attended and $1,000 for each committee meeting attended. In lieu of the foregoing meeting fees, if attendance is by telephone, they receive a fee of $200 per hour. The Chairman of the Audit Committee receives an additional annual retainer of $10,000. The Chairs of other committees of our board of directors receive an additional annual retainer of $5,000. All directors are reimbursed for reasonable expenses incurred in their service on our board of directors.

Indemnification

Our certificate of incorporation and bylaws provide that we will indemnify our officers and directors to the fullest extent permitted by law. Additionally, we have entered into separate indemnification agreements with our officers and the members of our board of directors to provide additional indemnification benefits, including the right to receive in advance reimbursements for expenses incurred in connection with a defense for which the officer or director is entitled to indemnification.

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Executive Compensation

The Summary Compensation Table below sets forth the cash and non-cash compensation information for the years ended December 31, 2005, 2004 and 2003 for the Chief Executive Officer and our other executive officers whose salary and bonus earned for services rendered to us exceeded $100,000 for the most recent fiscal year.

Summary Compensation Table

		Annual Compensation			Long-Term Compensation: Awards		Long-Term Compensation: Payouts	
Name And Principal Position	**Year**	**Salary ($)**	**Bonus ($)(1)**	**Other Annual Compensation (2)($)**	**Restricted Stock Award(s) ($)**	**Securities Underlying Options (#)(3)**	**LTIP Payouts ($)**	**All Other Compensation (4)($)**
J. Darby Seré	2005	$ 255,600	$ 182,235	$ 11,305				$ 6,300
	2004	243,360	70,574	6,881		106,660		6,150
Chairman of the Board, President, and Chief Executive Officer	2003	231,840	63,756	7,448		319,980		7,000
William C. Rankin	2005	$ 211,800	$ 154,725	$ 15,071				$ 6,300
	2004	201,720	58,499	14,664		93,340		6,000
Executive Vice President and Chief Financial Officer	2003	192,144	52,840	12,413		280,020		6,000
Philip G. Malone	2005	$ 119,160	$ 36,940					$ 4,263
	2004	109,163	22,924					4,280
Senior Vice President Exploration	2003	121,800	33,495					4,598
Brett S. Camp	2005	$ 161,180	$ 49,966					$ 5,932
	2004	126,000	36,540					4,765
Senior Vice President Operations	2003	119,400	32,835					4,506

(1) Bonuses represent the amount earned for the year indicated and are generally paid in the following year. Messrs. Seré and Rankin received $79,995 and $70,005, respectively, of bonuses for 2005 during 2005 prior to our merger with our majority-owned subsidiary.
(2) Other compensation includes paid vacation time not taken by the named executives.
(3) These options were granted pursuant to the GeoMet Resources, Inc. Stock Acquisition and Stockholders Agreement, which allowed Messrs. Seré and Rankin collectively to be granted options to purchase up to 1.2 million shares of our common stock. These options have an exercise price of $2.50 per share and fully vested on January 30, 2006. These options expire 10 years after the date of grant.
(4) Represents employer matching contributions to our 401(k) plan.

Option/SAR Grants in Fiscal Year 2005

There were no options/SARs granted during this period.

Aggregated Option/SAR Exercises and December 31, 2005 Option/SAR Values

The following table sets forth for each of the named executive officers the number of shares subject to both exercisable and unexercisable stock options in respect of our common stock, as well as the value of unexercisable in-the-money options as of the end of December 31, 2005. We have not granted any SARS.

Name	Shares Acquired on Exercise (#)	Value Realized ($)	Number of Securities Underlying Unexercised Options/SARs at December 31, 2005 (shares)		Value of Unexercised In the Money Options/SARs at December 31, 2005 ($)(1)	
			Exercisable	**Unexercisable(2)**	**Exercisable**	**Unexercisable**
J. Darby Seré			462,200	177,760	$ 4,853,100	$ 1,866,480
William C. Rankin			404,480	155,560	$ 4,247,040	$ 1,633,380

(1) Calculated using the price of $13.00 received in the private offering on January 30, 2006 less the applicable exercise price multiplied by the number of option shares.

(2) All stock options became vested and immediately exercisable on January 30, 2006, the closing date of our private placement offering. Mr. Seré exercised and sold 160,000 shares in connection with the private placement offering.

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The stock options granted to these executive officers were granted pursuant to the GeoMet Resources, Inc. Stock Acquisition and Stockholders Agreement. These options have an exercise price of $2.50 per share and fully vested on January 30, 2006, the date on which Yorktown and its permitted transferees ceased to own at least 60% of our common stock. These options expire 10 years after the dates of grant.

Employment Agreements and Other Arrangements

Mr. Seré and Mr. Rankin executed employment agreements in December 2000, each agreement having initial terms that expired in December 2003. The agreements are substantially similar in form, with differences in titles, responsibilities and base salary. Following the expiration of the initial term, each agreement has been automatically extended for an additional one-year term, and will continue to be automatically extended for an additional year, unless we or the executive gives written notice to the contract party 90 days before the end of subsequent additional term.

Each agreement provides that, if the executive s employment is terminated by us without cause, or by the executive for good reason, that we will pay him, within 30 days of the date of termination, a lump sum amount equal to 18-month s base salary, plus the executive s base salary, reimbursable expenses and vacation accrued but unpaid through the date of termination. In addition, we will continue to provide group medical and dental insurance to the executive and the executive s family for a period of 18 months after the date of termination.

Officer Bonus Program

Our officer bonus compensation has been previously determined at the sole discretion of the compensation committee and was not subject to any formal plan. Beginning in 2006, certain of our officers bonus compensation will be based on the achievements of targets of four performance measures, including annual production, year-end proved reserve quantities, annual EBITDA, and three-year finding and development costs. Each of these performance measures carries a 25% weight in determining the total bonus amount. The bonus amount determined by achievements of the targets of these performance measures will range from a minimum of 25% of each such officer s bonus target percentage of annual base salary compensation to a maximum of 175% of such target percentage. The bonus target percentages of annual base salary compensation for our chief executive officer, our chief financial officer and our two senior vice presidents are 60%, 50%, 40%, and 40%, respectively. Our chief executive officer may recommend that any or all of the individual bonuses (except his own), as so determined be adjusted by an absolute 25% of the bonus target percentage of annual base salary compensation based on subjective individual performance factors. The compensation committee may make further adjustments to increase or decrease individual bonuses based on subjective performance factors.

Incentive Bonus Pool Plan

We established an Incentive Bonus Pool Plan (the Bonus Plan) in 2001 to provide a performance incentive and a retention vehicle for certain of our key non-executive management, technical and professional employees. Our compensation committee administers the Bonus Plan. Awards consist of pool units that are fictional ownership units in the incentive bonus pool where the maximum number of pool units of the Bonus Plan cannot exceed 1,000 units. Amounts credited to the incentive bonus pool for a plan year equal 2% of our annual un-audited consolidated pre-tax income. Awards under the Bonus Plan are paid in installments over three years, 50% of the award in year one and installments of 25% each are paid in the succeeding two years, subject to the participant s continuing employment with us. In the event of change of control as defined each participant s unpaid incentive bonus becomes fully vested. Our board of directors may terminate the Bonus Plan at any time and pay outstanding awards.

Description of 2005 Stock Option Plan

We have adopted the GeoMet, Inc. 2005 Stock Option Plan (the 2005 Plan). Our board of directors believes that equity-based incentive compensation plans provide an important means of attracting, retaining and motivating employees, non-employee directors, and other service providers. The 2005 Plan is intended to promote and advance our interests by providing our employees, non-employee directors and other service

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providers added incentive to continue in our service through a more direct interest in the future success of our operations. Our board of directors believes that employees, non-employee directors, and other service providers who have an investment in us are more likely to meet and exceed performance goals. In 2001, the Company established a stock option plan that authorizes the granting of options to key employees to acquire common stock of its majority-owned subsidiary at prices equivalent to the market value at the date of grant. The options have a term of seven years, vest evenly over four years and become exercisable on each of the first four anniversary dates of issuance. Effective with the merger of the majority-owned subsidiary into GeoMet, all of the outstanding options under this plan became fully vested and the options were exchanged for options to acquire common stock of GeoMet under the 2005 Plan. Our board of directors and stockholders recently approved the GeoMet, Inc. 2006 Long-Term Incentive Plan discussed below, under which an additional 2,000,000 shares of our common stock were reserved for awards to be granted. In conjunction with the approval of the 2006 Plan, we will not grant any additional awards under our 2005 Plan; however, we will continue to issue shares of our common stock upon exercise of awards that we have previously granted. The following is a summary of the 2005 Plan.

Administration. The 2005 Plan provides for administration by our compensation committee. Among the powers granted to the compensation committee are (1) the authority to interpret the 2005 Plan and the options granted thereunder, (2) determine eligibility for participation in the 2005 Plan, (3) prescribe the form of the option agreements embodying options granted under the 2005 Plan, (4) make administrative guidelines and other regulations for carrying out the 2005 Plan and make changes in such guidelines and regulations as the compensation committee deems proper and (5) take any and all other actions it deems necessary or advisable for the proper operation or administration of the 2005 Plan. The compensation committee also has authority with respect to all matters relating to the discharge of its responsibilities and the exercise of its authority under the 2005 Plan. The 2005 Plan provides for indemnification of compensation committee members for personal liability incurred related to any action, interpretation or determination made in good faith with respect to the 2005 Plan and awards made under the 2005 Plan.

Eligibility. Our employees, non-employee directors and other service providers who, in the opinion of the compensation committee, are in a position to make a significant contribution to our success are eligible to participate in the 2005 Plan. The compensation committee determines the type and size of award and sets the terms, conditions, restrictions and limitations applicable to the award within the confines of the terms of the 2005 Plan.

Available Shares. The maximum number of shares available for grant under the plan is 1,200,000 shares of our common stock plus any shares of common stock that become available under the 2005 Plan for any reason other than exercise. The number of shares available for award under the 2005 Plan is subject to adjustment for certain corporate changes in accordance with the provisions of the 2005 Plan. Shares of common stock issued pursuant to the 2005 Plan may be shares of original issuance or treasury shares or a combination of those shares.

Stock Options. The 2005 Plan provides for the grant of incentive stock options intended to meet the requirements of Section 422 of the Code and nonqualified stock options that are not intended to meet those requirements. Incentive stock options may be granted only to our employees. All options will be subject to terms, conditions, restrictions and limitations established by the compensation committee, as long as they are consistent with the terms of the 2005 Plan.

The compensation committee will determine when an option will vest and become exercisable. No option will be exercisable more than ten years after the date of grant (or, in the case of an incentive stock option granted to a 10% shareholder, five years after the date of grant). Unless otherwise provided in the option award agreement, options terminate within a certain period of time following a participant s termination of employment or service for any reason other than cause (one year in the case of an incentive stock option and two years in the case of a non-qualified stock option) or for cause (three months).

The exercise price of a stock option granted under the 2005 Plan shall be determined by the compensation committee but may not, in any event, be less than the fair market value of the common stock on the date of grant.

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Incentive stock options must be granted at 100% of fair market value (or, in the case of an incentive stock option granted to a 10% shareholder, 110% of fair market value).

The exercise price of a stock option may be paid (i) in cash, (ii) with the consent of the compensation committee, by the execution of a promissory note and/or a combination of cash and execution of a promissory note, or (iii) with the consent of the compensation committee and if and to the extent provided for under the option agreement for such option, in cash and/or by delivery of shares of common stock already owned by the optionee having an aggregate fair market value (determined as of the date of exercise) equal to the purchase price.

New Plan Benefits. The number of awards that will be received by or allocated to our executive officers, non-employee directors, employees, and other service providers under the 2005 Plan is undeterminable at this time.

Corporate Change. Unless an award agreement provides otherwise, in the event of a participant s involuntary termination of employment or service other than for death, cause, or inability to perform or a voluntary termination for good reason, within one year after a corporate change (which may include, among others, the dissolution or liquidation of us, certain reorganizations, mergers or consolidations, the sale of all or substantially all our assets, or the closing of an underwritten public offering of our common stock), the board of directors serving prior to the date of the applicable event shall accelerate the exercise dates of all outstanding options, and may, in its discretion, without obtaining stockholder approval, pay cash to any or all optionees in exchange for the cancellation of their outstanding options.

Withholding Taxes. All applicable withholding taxes will be deducted from any payment made under the 2005 Plan, withheld from other compensation payable to the participant, or be required to be paid by the participant prior to the making of any payment of cash or common stock under the 2005 Plan. Payment of withholding taxes may be made by withholding shares of common stock from any payment of common stock due or by the delivery by the participant of previously acquired shares of common stock, in either case having an aggregate fair market value equal to the amount of the required withholding taxes. No payment will be made and no shares of common stock will be issued pursuant to any award made under the 2005 Plan until the applicable tax withholding obligations have been satisfied.

Transferability. No award may be sold, transferred, pledged, exchanged, or disposed of, except by will or by the laws of descent and distribution. All awards are exercisable during the lifetime of the optionee only by the optionee, or if the optionee is legally incompetent, by the optionee s legal representative. If provided in the award agreement, nonqualified stock options may be transferred by a participant to a permitted transferee. In connection with a divorce, a participant may request that we agree to observe the terms of a domestic relations order with respect to all or part of an award granted to a participant. Our decision regarding such a request will be made by the compensation committee based upon our interests. The compensation committee s decision need not be uniform between participants.

Amendment. Our board of directors may suspend, terminate, amend or modify the plan, but may not without the approval of the holders of a majority of the shares of our common stock make any alteration or amendment that operates (1) to increase the total number of shares of common stock as to which options may be granted under the 2005 Plan (other than adjustments in connection with certain corporate reorganizations and other events), (2) to extend the term of the 2005 Plan or the exercise period beyond the ten-year maximum provided in the 2005 Plan, (3) to decrease the minimum purchase price provided in the 2005 Plan, or (4) to make any other change requiring shareholder approval under any applicable rule, regulation, or procedure of any national securities exchange or securities association upon which any of our securities are listed. No suspension, termination, amendment or modification of the plan will adversely affect in any material way any award previously granted under the 2005 Plan, without the consent of the participant.

Effectiveness. The 2005 Plan became effective in April 2005. Unless terminated earlier, the 2005 Plan will terminate on the tenth anniversary of the effective date. However, we have suspended granting any additional awards in conjunction with the approval of our 2006 Plan, which is discussed below.

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Description of 2006 Long-Term Incentive Plan

The GeoMet, Inc. 2006 Long-Term Incentive Plan (the 2006 Plan), under which 2,000,000 shares of our common stock have been reserved for awards to be granted, has been approved by our board of directors and stockholders. The purpose of the 2006 Plan is to promote and advance our interests by providing our officers, independent directors, and technical and professional employees added incentive to continue in our service through a more direct interest in the future success of our operations. We believe that officers, independent directors, and technical and professional employees who have an investment in us are more likely to meet and exceed performance goals. We believe that the various equity-based incentive compensation vehicles provided for under the 2006 Plan, which may include stock options, restricted and unrestricted stock, restricted stock units, stock appreciation rights, performance awards and other incentive awards, are needed to maintain and promote our competitive ability to attract, retain and motivate officers, independent directors, and technical and professional employees. The following is a summary of the 2006 Plan.

Purposes. The 2006 Plan allows for the grant of stock options, stock awards, restricted stock, restricted stock units, stock appreciation rights, performance awards, and other incentive awards to our employees and independent directors who are in a position to make a significant contribution to the success of us and our affiliates. The purposes of the 2006 Plan are to attract and retain employees and independent directors, further align their interests with shareholder interests, and closely link compensation with company performance. The 2006 Plan will provide an essential component of the total compensation package, reflecting the importance that we place on aligning the interests of employees and independent directors with those of our stockholders.

Administration. The 2006 Plan provides for administration by the Compensation Committee or another committee of our board of directors (the Committee). However, each member of the Committee must (1) meet independence requirements of the exchange on which our common stock is listed (if any), (2) be a non-employee director within the meaning of Rule 16b-3 under the Securities Exchange Act of 1934, and (3) be an outside director under Section 162(m) of the Internal Revenue Code of 1986, as amended (the Code). With respect to awards granted to non-employee directors, the Committee is the board of directors. Among the powers granted to the Committee are (1) the authority to operate, interpret and administer the 2006 Plan, (2) determine eligibility for and the amount and nature of awards, (3) establish rules and regulations for the operation of the 2006 Plan, accelerate the exercise, vesting or payment of an award if the acceleration is in our best interest, (4) require participants to hold a stated number or percentage of shares acquired pursuant to an award for a stated period of time, and (5) establish other terms and conditions of awards made under the 2006 Plan. The Committee also has authority with respect to all matters relating to the discharge of its responsibilities and the exercise of its authority under the 2006 Plan. The 2006 Plan provides for indemnification of Committee members for personal liability incurred related to any action, interpretation, or determination made in good faith with respect to the Plan and awards made under the 2006 Plan.

Eligibility. Our employees and independent directors who, in the opinion of the Committee, are in a position to make a significant contribution to our success and our affiliates are eligible to participate in the 2006 Plan. The Committee determines the type and size of award and sets the terms, conditions, restrictions and limitations applicable to the award within the confines of the terms of the 2006 Plan.

Available Shares. The maximum number of shares available for grant under the 2006 Plan is 2,000,000 shares of common stock plus any shares of common stock that become available under the 2006 Plan for any reason other than exercise. The number of shares available for award under the 2006 Plan is subject to adjustment for certain corporate changes in accordance with the provisions of the 2006 Plan. Shares of common stock issued pursuant to the 2006 Plan may be shares of original issuance or treasury shares or a combination of those shares.

The maximum number of shares of common stock available for grant of awards under the 2006 Plan to any one participant is (1) 200,000 shares during the fiscal year in which the participant begins work for us and (2) 100,000 shares during each fiscal year thereafter.

Stock Options. The 2006 Plan provides for the grant of incentive stock options intended to meet the requirements of Section 422 of the Code and nonqualified stock options that are not intended to meet those requirements. Incentive stock options may be granted only to our employees. All options will be subject to terms, conditions, restrictions, and limitations established by the Committee, as long as they are consistent with the terms of the 2006 Plan.

The Committee will determine when an option will vest and become exercisable. No option will be exercisable more than ten years after the date of grant (or, in the case of an incentive stock option granted to a 10% shareholder, five years after the date of grant). Unless otherwise provided in the option award agreement, options terminate within a certain period of time following a participant s termination of employment or service for any reason other than cause (12 months) or for cause (30 days).

Generally, the exercise price of a stock option granted under the 2006 Plan may not be less than the fair market value of the common stock on the date of grant. However, the exercise price may be less if the option is granted in connection with a transaction and complies with special rules under Section 409A of the Code. Incentive stock options must be granted at 100% of fair market value (or, in the case of an incentive stock option granted to a 10% shareholder, 110% of fair market value).

The exercise price of a stock option may be paid (1) in cash, (2) in the discretion of the Committee, with previously acquired nonforfeitable, unrestricted shares of common stock that have been held for six months and that have an aggregate fair market value at the time of exercise equal to the total exercise price, or (3) a combination of those shares and cash. In addition, in the discretion of the Committee, the exercise price may be paid by delivery to us or our designated agent of an executed irrevocable option exercise form together with irrevocable instructions to a broker-dealer to sell or margin a sufficient portion of the shares of common stock with respect to which the option is exercised and deliver the sale or margin loan proceeds directly to us to pay the exercise price and any required withholding taxes.

Stock Appreciation Rights (SARs). A stock appreciation right entitles the participant to receive an amount in cash and/or shares of Common Stock, as determined by the Committee, equal to the amount by which our common stock appreciates in value after the date of the award. The Committee will determine when the SAR will vest and become exercisable. Generally, the exercise price of a SAR will not be less than the fair market value of the common stock on the date of grant. However, the exercise price may be less if the stock is granted in connection with a transaction and complies with special rules under Section 409A of the Code. No SAR will be exercisable later than ten years after the date of the grant. The Committee will set other terms, conditions, restrictions and limitations on SARs, including rules as to exercisability after termination of employment or service.

Stock Awards. Stock awards are shares of common stock awarded to participants that are subject to no restrictions. Stock awards may be issued for cash consideration or for no cash consideration.

*Restricted Stock and Restricted Stock Units (RSU*s). Restricted stock is shares of common stock that must be returned to us if certain conditions are not satisfied. The Committee will determine the restriction period and may impose other terms, conditions, and restrictions on restricted stock, including vesting upon achievement of performance goals pursuant to a performance award and restrictions under applicable securities laws. The Committee also may require the participant to pay for restricted stock. Subject to the terms and conditions of the award agreement related to restricted stock, a participant holding restricted stock will have the right to receive dividends on the shares of restricted stock during the restriction period, vote the restricted stock, and enjoy all other shareholder rights related to the shares of common stock. Upon expiration of the restriction period, the participant is entitled to receive shares of common stock not subject to restriction.

Restricted stock units are fictional shares of common stock. The Committee will determine the restriction period and may impose other terms, conditions, and restrictions on RSUs. Upon the lapse of restrictions, the participant is entitled to receive one share of common stock or an amount of cash equal to the fair market value of one share of common stock as provided in the award agreement. An award of RSUs may include the grant of a tandem cash dividend right or dividend unit right. A cash dividend right is a contingent right to receive an amount in cash equal to the cash distributions made with respect to a share of common stock during the period

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the RSU is outstanding. A dividend unit right is a contingent right to have additional RSUs credited to the participant equal to the number of shares of common stock (at fair market value) that may be purchased with the cash dividends. Restricted stock unit awards are considered nonqualified deferred compensation subject to Section 409A of the Code and will be designed to comply with that section.

Performance Awards. A performance award is an award payable in cash or common stock (or a combination thereof) upon the achievement of certain performance goals over a performance period. Performance awards may be combined with other awards to impose performance criteria as part of the terms of the other awards. For each performance award, the Committee will determine (1) the amount a participant may earn in the form of cash or shares of common stock or a formula for determining the amount payable to the participant, (2) the performance criteria and level of achievement versus performance criteria that will determine the amount payable or number of shares of common stock to be granted, issued, retained and/or vested, (3) the performance period over which performance is to be measured, which may not be shorter than one year, (4) the timing of any payments to be made, (5) restrictions on the transferability of the award, and (6) other terms and conditions that are not inconsistent with the 2006 Plan.

The maximum amount that may be paid in cash pursuant to a performance award each fiscal year is $1 million. If an award provides for a performance period longer than one fiscal year, the limit will be multiplied by the number of full fiscal years in the performance period. The performance measure(s) to be used for purposes of performance awards may be described in terms of objectives that are related to the individual participant or objectives that are company-wide or related to a subsidiary, division, department, region, function or a business unit in which the participant is employed, and may consist of one or more or any combination of the following criteria:

Earnings or earnings per share (whether on a pre-tax, after-tax, operational or other basis)	Accomplishment of mergers, acquisitions, dispositions, public offerings or similar extraordinary business transactions
Return on equity	One or more operating ratios
Return on assets or net assets	Stock price
Revenues	Total shareholder return
Income or operating income	Cash flow or EBITDA
Expenses or costs or expense levels or cost levels	Net borrowing, debt leverage levels, credit quality or debt ratings
Return on capital or invested capital or other related financial measures	Net asset value per share
Capital expenditures	Profit margin
Economic value added	Operating profit
Individual business objectives	Growth in reserves
Growth in production	Finding and development cost per Mcf
Reserve replacement ratio	

Performance awards may be designed to comply with the performance-based compensation requirements of Section 162(m) of the Code. Section 162(m) of the Code limits our income tax deduction for compensation paid to our Chief Executive Officer and each of our four other highest paid officers to $1 million each year. There is an exception to the $1 million deduction limitation for performance-based compensation. To the extent that awards are intended to qualify as performance-based compensation under Section 162(m), the performance criteria will be established in writing by the Committee not later than 90 days after the commencement of the performance period, based on one or more, or any combination, of the performance criteria listed above. The Committee may reduce, but not increase, the amount payable and the number of shares to be granted, issued, retained or vested pursuant to a performance award. Prior to payment of compensation under a performance award intended to comply with Section 162(m), the Committee will certify the extent to which the performance goals and other criteria are achieved.

Other Incentive Awards. The Committee may grant other incentive awards under the 2006 Plan based upon, payable in or otherwise related to, shares of common stock if the Committee determines that the other incentive

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awards are consistent with the purposes of the plan. Other incentive awards will be subject to any terms, conditions, restrictions, or limitations established by the Committee. Payment of other incentive awards will be made at the times and in the forms, which may be cash, shares of common stock, or other property, established by the Committee.

New Plan Benefits. The number of awards that will be received by or allocated to our executive officers, independent directors, and employees under the 2006 Plan is undeterminable at this time.

Corporate Change. Unless an award agreement provides otherwise, in the event of a participant s involuntary termination of employment or service other than for death, cause, or inability to perform or a voluntary termination for good reason, within one year after a corporate change affecting us (which may include, among others, our dissolution or liquidation, certain reorganizations, a merger or consolidation, the sale of all or substantially all of our assets and our affiliates), any time periods, conditions or contingencies relating to exercise or realization of, or lapse of restrictions under, awards will be automatically accelerated or waived so that (1) if no exercise of the award is required, the award may be realized in full at the time of termination, or (2) if exercise of the award is required, the award may be exercised in full beginning at the time of termination. In addition, to the extent surrender or settlement of awards will not result in negative tax consequences to participants, the Committee may, without consent of a participant, (1) require participants to surrender any outstanding options or stock appreciation rights in exchange for an equivalent amount of cash, common stock, securities of another company or any combination thereof equal to the difference between fair market value of the common stock and the exercise or grant price, or (2) require that participants receive payments in settlement of restricted stock, restricted stock units (and related cash dividend rights and dividend unit rights, as applicable), performance awards or other incentive awards in an amount equivalent to the value of those awards.

Withholding Taxes. All applicable withholding taxes will be deducted from any payment made under the 2006 Plan, withheld from other compensation payable to the participant, or be required to be paid by the participant prior to the making of any payment of cash or common stock under the 2006 Plan. Payment of withholding taxes may be made by withholding shares of common stock from any payment of common stock due or by the delivery by the participant to us of previously acquired shares of common stock, in either case having an aggregate fair market value equal to the amount of the required withholding taxes. No payment will be made and no shares of common stock will be issued pursuant to any award made under the 2006 Plan until the applicable tax withholding obligations have been satisfied.

Transferability. No award may be sold, transferred, pledged, exchanged, or disposed of, except by will or by the laws of descent and distribution. If provided in the award agreement, nonqualified stock options may be transferred by a participant to a permitted transferee. In connection with a divorce, a participant may request that we agree to observe the terms of a domestic relations order with respect to all or part of an award granted to a participant. Our decision regarding such a request will be made by the Committee based upon our best interests. The Committee s decision need not be uniform between participants.

Amendment. Our board of directors may suspend, terminate, amend, or modify the 2006 Plan, but may not without the approval of the holders of a majority of the shares of our common stock make any alteration or amendment that operates (1) to increase the total number of shares of common stock that may be issued under the 2006 Plan (other than adjustments in connection with certain corporate reorganizations and other events), (2) to change the designation or class of persons eligible to receive awards under the 2006 Plan, or (3) to effect any change for which stockholder approval is required by or necessary to comply with applicable law or the listing requirements of the Nasdaq Global Market or any exchange or association on which our common stock is then listed or quoted. Upon termination of the 2006 Plan, the terms and provisions thereof will continue to apply to awards granted before termination. No suspension, termination, amendment, or modification of the plan will adversely affect in any material way any award previously granted under the 2006 Plan, without the consent of the participant.

Effectiveness. The 2006 Plan became effective in April 2006. Unless terminated earlier, the 2006 Plan will terminate on the day before the tenth anniversary of the effective date.

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SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth information as of March 31, 2006 with respect to the beneficial ownership of our common stock by (i) stockholders owning 5% or more of our outstanding common stock, (ii) our directors, (iii) our named executive officers, and (iv) our executive officers and directors as a group before this offering and after the completion of this offering.

Unless otherwise indicated in the footnotes to this table each of the stockholders named in this table has sole voting and investment power with respect to the shares indicated as beneficially owned.

		Percentage of Shares Beneficially Owned(2)	
Name and Address of Beneficial Owner	Amount(1)	Before Offering	After Offering
Yorktown Energy Partners IV, L.P. 410 Park Avenue New York, New York 10022	16,202,696	49.7%	43.2%
W. Howard Keenan, Jr. 410 Park Avenue New York, New York 10022	16,202,696(3)	49.7%	43.2%
J. Darby Seré 909 Fannin, Suite 3208 Houston, Texas 77010	1,440,150(4)	4.4%	3.8%
William C. Rankin 909 Fannin, Suite 3208 Houston, Texas 77010	1,260,300(5)	3.9%	3.3%
Philip G. Malone 5336 Stadium Trace Parkway Suite 206 Birmingham, Alabama 35244	887,368(6)	2.7%	2.4%
Brett S. Camp 5336 Stadium Trace Parkway Suite 206	887,368(7)	2.7%	2.4%

Birmingham, Alabama 35244			
J. Hord Armstrong, III 909 Fannin, Suite 3208 Houston, Texas 77010		%	%
James C. Crain 909 Fannin, Suite 3208 Houston, Texas 77010		%	%
Stanley L. Graves 909 Fannin, Suite 3208 Houston, Texas 77010		%	%
Charles D. Haynes 909 Fannin, Suite 3208 Houston, Texas 77010		%	%
All executive officers and directors as a group (nine persons)	20,677,882	63.4%	55.1%

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(1) Unless otherwise indicated, all shares of stock are held directly with sole voting and investment power. Securities not outstanding, but included in the beneficial ownership of each such person are deemed to be outstanding for the purpose of computing the percentage of outstanding securities of the class owned by such person, but are not deemed to be outstanding for the purpose of computing percentage of the class owned by any other person. The total number includes shares issued and outstanding as of March 31, 2006, plus shares which the owner shown above has the right to acquire within 60 days after the date of this prospectus.

(2) For purposes of calculating the percent of the class outstanding held by each owner shown above with a right to acquire additional shares, the total number of shares excludes the shares which all other persons have the right to acquire within 60 days after the date of this prospectus, pursuant to the exercise of outstanding stock options and warrants.

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(3) Represents shares of common stock owned by Yorktown Energy Partners IV, L.P. W. Howard Keenan, Jr. is a member and a manager of the general partner of Yorktown Energy Partners IV, L.P. and may be deemed to beneficially own the shares held by that entity.

(4) Includes options to purchase up to 479,960 shares of common stock, which are exercisable within 60 days from the date of this prospectus and 456,000 shares of common stock that are held in an investment limited partnership under the control of Mr. Seré, and for which he holds voting and dispositive power.

(5) Includes options to purchase up to 560,040 shares of common stock, which are exercisable within 60 days from the date of this prospectus, and 400,000 shares of common stock that are held in an investment limited partnership under the control of Mr. Rankin, and for which he holds voting and dispositive power.

(6) Includes 443,684 shares of common stock held by the spouse of Philip G. Malone.

(7) Includes 443,684 shares of common stock held by the spouse of Brett S. Camp.

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CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

On April 14, 2005, the merger date of our majority-owned subsidiary with and into GeoMet, we issued to each minority interest owner and holder of incentive stock options of our majority-owned subsidiary an option to purchase shares of our common stock at the per share exchange value of $7.64 (the non-dilution option). Within 30 days of issuance, the holder of the non-dilution option could exercise the option to purchase shares of our common stock with cash or a loan from us, up to a certain amount of our shares of common stock to prevent any dilution that resulted from the merger. Notes issued to purchase any stock are full recourse, earn interest at an annual rate of 6%, and mature on the earlier of April 14, 2009 or 60 days after the holder ceases to be an employee or the occurrence of a Triggering Transaction as defined in the non-dilution option agreement. The option holders exercised non-dilution options to purchase 1,456,660 shares of our common stock. The option holders financed the exercise of these options using approximately $10.9 million in notes and $0.2 million in cash. Certain of our executive officers and members of their families held approximately $4.5 million of these notes. All of the loans to our executive officers and their family members were repaid in full with interest upon the closing of our private equity offering in January 2006, as were all but $400,000 of the loans to others.

On December 8, 2000, GeoMet was formed through the issuance of 7.2 million shares of common stock for $18 million in cash to Yorktown Energy Partners IV, L.P., our controlling stockholder, which is a partnership managed by Yorktown Partners LLC and organized in 1999 to make direct investments in the energy industry on behalf of certain institutional investors, and 800,000 shares of common stock to certain of our executive officers for $400,000 in cash and notes receivable in the amount of $1.6 million under the terms of an agreement between us, Yorktown, and such executive officers. The notes were issued only to certain executive officers, were full recourse, and accrued interest at an annual rate of 5.87% and were to become due and payable on April 14, 2009, or earlier upon certain circumstances. These loans to our executive officers were repaid with interest upon the closing of our private equity offering in January 2006.

In 2003, we increased the authorized common stock by 8,000,000 shares and issued 4,000,000 and 8,000,000 shares of common stock on May 19 and September 22, respectively at $2.50 per share, to the existing stockholders in proportion to their original ownership, for cash of $27.3 million and notes receivable of $2.7 million. On April 27, 2004, we issued 4,000,000 shares of common stock at $2.50 per share, to our existing stockholders in proportion to their original ownership, for cash of $9.1 million and notes receivable of $0.9. The notes were issued only to certain executive officers, were full recourse and accrued interest at an annual rate of 5.87% and were to become due and payable on April 14, 2009, or earlier upon certain circumstances. In connection with the closing of our private equity offering in January 2006, all of these loans were repaid in full with interest.

On July 21, 2003, we loaned Mr. Rankin, our chief financial officer, $250,000 to provide liquidity in connection with a divorce settlement so that Mr. Rankin could retain ownership of his shares of common stock. The note was full recourse and accrued interest at an annual rate of 5.87% and was to become due and payable on April 14, 2009, or earlier upon certain circumstances. The loan was repaid in full with interest upon the closing of our private equity offering in January 2006.

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DESCRIPTION OF CAPITAL STOCK

Pursuant to our amended certificate of incorporation, we have the authority to issue an aggregate of 135,000,000 shares of capital stock, consisting of 125,000,000 shares of common stock, par value $0.001 per share, and 10,000,000 shares of preferred stock, par value $0.001 per share.

Selected provisions of our organizational documents are summarized below. Copies of our organizational documents will be provided upon request and are available on our website, *www.geometinc.com*. In addition, you should be aware that the summary below does not give full effect to the terms of the provisions of statutory or common law which may affect your rights as a stockholder.

Common Stock

As of March 31, 2006, we had a total of 32,614,021 shares of common stock outstanding. Following the completion of this offering and assuming that the underwriters exercise their option to purchase additional shares in full, we will have 38,364,021 shares of common stock outstanding based on the number of shares 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. As of March 31, 2006 we have granted options to purchase 2,172,552 shares, of which 1,770,990 remain outstanding, and 2,227,448 shares remain available for future grants.

Voting rights. Each share of common stock is entitled to one vote in the election of directors and on all other matters submitted to a vote of our stockholders. Our stockholders may not cumulate their votes in the election of directors.

Dividends, distributions and stock splits. Holders of our common stock are entitled to receive dividends if, as and when such dividends are declared by our board out of assets legally available therefor after payment of dividends required to be paid on shares of preferred stock, if any.

Liquidation. In the event of any dissolution, liquidation, or winding up of our affairs, whether voluntary or involuntary, after payment of our debts and other liabilities and making provision for any holders of our preferred stock who have a liquidation preference, our remaining assets will be distributed ratably among the holders of common stock.

Fully paid. All the shares of common stock to be outstanding upon completion of this offering will be fully paid and nonassessable.

Other rights. Holders of our common stock have no redemption or conversion rights but do have preemptive rights to subscribe for our securities, except in certain circumstances, including, but not limited to, a public offering of our stock.

Preferred Stock

Our board of directors has the authority to issue up to 10,000,000 shares of preferred stock in one or more series and to fix the rights, preferences, privileges and restrictions thereof, including dividend rights, dividend rates, conversion rates, voting rights, terms of redemption, redemption prices, liquidation preferences, and the number of shares constituting any series or the designation of that series, which may be superior to those of the common stock, without further vote or action by the stockholders. There will be no shares of preferred stock outstanding, and we have no present plans to issue any preferred stock.

One of the effects of undesignated preferred stock may be to enable our board of directors to render it more difficult to or to discourage an attempt to obtain control of us by means of a tender offer, proxy contest, merger or otherwise, and as a result to protect the continuity of our management. The issuance of shares of the preferred stock by our board of directors as described above may adversely affect the rights of the holders of common stock. For example, preferred stock issued by us may rank prior to the common stock as to dividend rights, liquidation preference or both, may have full or limited voting rights, and may be convertible into shares of common stock. Accordingly, the issuance of shares of preferred stock may discourage bids for our common stock or may otherwise adversely affect the market price of our common stock.

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Liability and Indemnification of Officers and Directors

Our certificate of incorporation contains certain provisions permitted under the Delaware General Corporation Law relating to the liability of directors. These provisions eliminate a director s personal liability for monetary damages resulting from a breach of fiduciary duty, except that a director will be personally liable:

- for any breach of the director s duty of loyalty to us or our stockholders;
- for acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of law;
- under Section 174 of the Delaware General Corporation Law relating to unlawful stock repurchases or dividends; or
- for any transaction from which the director derives an improper personal benefit.

These provisions do not limit or eliminate our rights or those of any stockholder to seek non-monetary relief, such as an injunction or rescission, in the event of a breach of a director s fiduciary duty. These provisions will not alter a director s liability under federal securities laws.

Our certificate of incorporation and bylaws also provide that we must indemnify our directors and officers against expenses, judgments, fines, and amounts paid in settlement incurred by such director or officer if he acted in good faith and in a manner he reasonably believed to be in or not opposed to the best interests of the corporation, and with respect to any criminal action or proceeding, had no reasonable cause to believe his conduct was unlawful. Our certificate of incorporation and bylaws also provide that we may advance expenses, as incurred, to our directors and officers in connection with a legal proceeding upon receipt of an undertaking by or on behalf of such director or officer to repay such amount unless it shall be ultimately determined that he is entitled to be indemnified by us as authorized by the certificate of incorporation and the bylaws.

Anti-Takeover Effects of Provisions of Delaware Law, Our Certificate of Incorporation and Bylaws

In connection with the closing of this offering, we will amend and restate our certificate of incorporation and bylaws. Our amended and restated certificate of incorporation and bylaws will contain and the Delaware General Corporation Law contains certain provisions that could discourage potential takeover attempts and make it more difficult for our stockholders to change management or receive a premium for their shares.

Delaware Law

We are subject to Section 203 of the Delaware General Corporation Law, an anti-takeover provision. In general, the provision prohibits a publicly-held Delaware corporation from engaging in a business combination with an interested stockholder for a period of three years after the date of the transaction in which the person became an interested stockholder. A business combination includes a merger, sale of 10% or more of our assets, and certain other transactions resulting in a financial benefit to the stockholder. For purposes of Section 203, an interested stockholder is defined to include any person that is:

- the owner of 15% or more of the outstanding voting stock of the corporation;
- an affiliate or associate of the corporation and was the owner of 15% or more of the voting stock outstanding of the corporation, at any time within three years immediately prior to the relevant date; or
- an affiliate or associate of the persons described in the foregoing bullet points.

However, the above provisions of Section 203 do not apply if:

- our board approves the transaction that made the stockholder an interested stockholder prior to the date of that transaction;

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after the completion of the transaction that resulted in the stockholder becoming an interested stockholder, that stockholder owned at least 85% of our voting stock outstanding at the time the transaction commenced, excluding shares owned by our officers and directors; or

on or subsequent to the date of the transaction, the business combination is approved by our board and authorized at a meeting of our stockholders by an affirmative vote of at least two-thirds of the outstanding voting stock not owned by the interested stockholder.

A corporation can elect not to be subject to Section 203 if a provision electing to opt out of Section 203 is included in the corporation s certificate of incorporation. Our amended and restated certificate of incorporation will not contain a provision opting out of Section 203. As a result, we anticipate that the provisions of Section 203 may encourage companies interested in acquiring us to negotiate in advance with our board.

Charter and Bylaw Provisions

Our amended and restated certificate of incorporation will provide that any action required or permitted to be taken by our stockholders may be effected only at a duly called annual or special meeting of the stockholders and not by written consent of the stockholders. Our amended and restated bylaws will provide that special meetings of stockholders may be called only by our chairman or chief executive officer, or by our chairman, president, or secretary at the request in writing of a majority of our board and not by our stockholders.

Directors may be removed with the approval of the holders of a majority of the shares then entitled to vote at an election of directors. Our amended and restated bylaws will provide that our directors may be removed by stockholders only for cause. Vacancies and newly created directorships resulting from any increase in the number of directors may be filled by election at an annual or special meeting of stockholders or by the affirmative vote of a majority of the directors then in office, though less than a quorum. If there are no directors in office, then an election of directors may be held in the manner provided by law.

Transfer Agent and Registrar

Our transfer agent and registrar for our common stock is American Stock Transfer & Trust Company.

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SHARES ELIGIBLE FOR FUTURE SALE

Prior to the date of this prospectus, there has been no public market for our common stock. The sale of a substantial amount of our common stock in the public market after we complete this offering, or the perception that such sales may occur, could adversely affect the prevailing market price of our common stock. Furthermore, because some of our shares will not be available for sale shortly after this offering due to the contractual and legal restrictions on resale described below and the fact that a substantial majority of our shares of common stock are subject to registration rights held by certain of our selling stockholders, the sale of a substantial amount of common stock in the public market after these restrictions lapse or in the future by these selling stockholders could adversely affect the prevailing market price of our common stock and our ability to raise equity capital in the future.

As of March 31, 2006, we had 32,614,021 shares of common stock outstanding. All of the shares of our common stock sold in this offering will be freely tradable without restriction or further registration under the Securities Act, unless the shares are purchased by affiliates as that term is defined in Rule 144 under the Securities Act and except certain shares that will be subject to the lock-up periods described under the caption Underwriting Lock-up Agreements , following the completion of this offering. Any shares purchased by an affiliate may not be resold except in compliance with Rule 144 volume limitations, manner of sale and notice requirements, pursuant to another applicable exemption from registration or pursuant to an effective registration statement. The shares of common stock held by our employees are restricted securities as that term is defined in Rule 144 under the Securities Act. These restricted securities may be sold in the public market by our employees only if they are registered or if they qualify for an exemption from registration under Rule 144 or Rule 144(k) under the Securities Act. These rules are summarized below.

Rule 144

In general, under Rule 144 as currently in effect, beginning 90 days after the date of this prospectus, a person or persons whose shares are aggregated, who have beneficially owned restricted shares for at least one year, including persons who may be deemed to be our affiliates, would be entitled to sell within any three-month period a number of shares that does not exceed the greater of (i) 1% of the number of shares of common stock then outstanding or (ii) the average weekly trading volume of our common stock during the four calendar weeks before a notice of the sale on SEC Form 144 is filed.

Sales under Rule 144 are also subject to certain manner of sale provisions and notice requirements and to the availability of certain public information about us.

Rule 144(k)

Under Rule 144(k), a person who is not deemed to have been one of our affiliates at any time during the 90 days preceding a sale, and who has beneficially owned the shares proposed to be sold for at least two years, including the holding period of any prior owner other than an affiliate, is entitled to sell these shares without complying with the manner of sale, public information, volume limitation or notice provisions of Rule 144.

Stock Issued Under Employee Plans

We intend to file registration statements on Form S-8 under the Securities Act to register approximately 4.4 million shares of common stock issuable, with respect to options and restricted stock units that have been exercised or will be granted under our employee plans or otherwise. These registration statements are expected to be filed following the effective date of the registration statement of which this prospectus is a part and will be effective upon filing. Shares issued upon the exercise of stock options or restricted stock will be eligible for resale in the public market without restriction after the effective date of the Form S-8 registration statements, subject to Rule 144 limitations applicable to affiliates. Under Rule 701 under the Securities Act, as currently in effect, each of our employees, officers, directors, and consultants who purchased or received shares pursuant to a written compensatory

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plan or contract is eligible to resell these shares 90 days after the effective date of this offering in reliance upon Rule 144, but without compliance with specific restrictions. Rule 701 provides that affiliates may sell their Rule 701 shares under Rule 144 without complying with the holding period requirement and that non-affiliates may sell their shares in reliance on Rule 144 without complying with the holding period, public information, volume limitation, or notice provisions of Rule 144.

Registration Rights

We entered into a registration rights agreement in connection with our private placement of common stock in the first quarter of 2006. In the registration rights agreement we agreed, for the benefit of the purchasers of our common stock in the private equity placement, to file a registration statement with the SEC, use our commercially reasonable efforts to cause the registration statement to become effective under the Securities Act, and continuously maintain the effectiveness of the registration statement under the Securities Act until the earliest of (i) the sale of all of the shares of common stock covered by the registration statement pursuant to a registration statement or Rule 144 under the Securities Act or any similar provision then in effect, (ii) such time as the shares of common stock covered by the registration statement and not held by affiliates of us are, in the opinion of our counsel, eligible for sale pursuant to Rule 144(k) (or any successor or analogous rule) under the Securities Act, or (iii) the second anniversary of the issuance of the shares of common stock covered by the registration statement.

We have filed a registration statement to satisfy our obligations under the registration rights agreement, which became effective immediately following this offering.

Additionally, all holders of our common stock sold in the private placement and, subject to agreement by the underwriters, the other existing beneficial holders of our common stock, including members of our management, and each of their respective direct and indirect transferees may elect to participate in the registration, of which this prospectus is a part, in order to resell their shares, subject to compliance with the registration rights agreement, cutback rights on the part of the underwriters, and other conditions and limitations that may be imposed by the underwriters.

The holders of shares of our common stock that are beneficiaries of the registration rights agreement and have elected to participate in this offering will not be able to sell any remaining shares owned by them and not included in this offering for a period of 180 days following the effective date of the registration statement, of which this prospectus is a part. The holders of shares of our common stock that are beneficiaries of the registration rights agreement and have elected not to participate in this offering also will not be able to sell any such shares for a period of 60 days following the effective date of the registration statement, of which this prospectus is a part.

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MATERIAL UNITED STATES FEDERAL INCOME TAX CONSIDERATIONS

FOR NON-UNITED STATES HOLDERS

To ensure compliance with Treasury Department Circular 230, prospective investors in our common stock are hereby notified that (1) any discussion of U.S. federal tax issues in this prospectus is not intended or written to be used, and cannot be used, for the purpose of avoiding penalties that may be imposed under the Internal Revenue Code, (2) any discussion of U.S. federal tax issues in this prospectus is written to support the promotion or marketing of the transactions or matters addressed herein and (3) prospective investors should seek advice based on their particular circumstances from an independent tax advisor.

The following is a summary of material United States federal income and, to a limited extent, estate tax considerations relating to the purchase, ownership and disposition of our common stock by persons that are non-United States holders (as defined below), but does not purport to be a complete analysis of all the potential tax considerations relating thereto. This summary is based upon the Internal Revenue Code of 1986 as amended (the Code) and regulations, administrative rulings and court decisions now in effect, all of which are subject to change, possibly on a retroactive basis. This summary deals only with non-United States holders that will hold our common stock as capital assets (generally, property held for investment) and does not address tax considerations applicable to investors that may be subject to special tax rules, including financial institutions, tax-exempt organizations, insurance companies, dealers in securities or currencies, traders in securities that elect to use a mark-to-market method of accounting for their securities holdings, persons that will hold the common stock as a position in a hedging transaction, straddle or conversion transaction for tax purposes, regulated investment companies, real estate investment trusts, or persons that have a functional currency other than the U.S. dollar. If a partnership holds the common stock, the tax treatment of a partner will generally depend upon the status of the partner and the activities of the partnership. If you are a partner of a partnership (including an entity treated as a partnership for United States federal income tax, purposes) holding our common stock, you should consult your tax advisor. Moreover, this summary does not discuss alternative minimum tax consequences, if any, or any state, local or foreign tax consequences to holders of the common stock. We have not sought any ruling from the Internal Revenue Service (the IRS) with respect to the statements made and the conclusions reached in the following summary, and there can be no assurance that the IRS will agree with such statements and conclusions. INVESTORS CONSIDERING THE PURCHASE OF OUR COMMON STOCK SHOULD CONSULT THEIR OWN TAX ADVISORS WITH RESPECT TO THE APPLICATION OF THE UNITED STATES FEDERAL INCOME AND ESTATE TAX LAWS TO THEIR PARTICULAR SITUATIONS AS WELL AS ANY TAX CONSEQUENCES ARISING UNDER THE LAWS OF ANY STATE, LOCAL OR FOREIGN TAXING JURISDICTION OR UNDER ANY APPLICABLE TAX TREATY.

As used in this discussion, a non-United States holder is a beneficial owner of common stock that for United States federal income tax purposes is not:

- an individual who is a citizen or resident of the United States, including an alien individual who is a lawful permanent resident of the United States or who meets the substantial presence test under Section 7701(b) of the Code;
- a corporation or partnership, or other entity treated as a corporation or partnership for United States federal income tax purposes, that was created or organized in or under the laws of the United States, any state thereof or the District of Columbia (unless, in the case of a partnership, U.S. Treasury regulations are adopted which provide otherwise);
- an estate whose income is subject to United States federal income taxation regardless of its source; or
- a trust (i) if it is subject to the supervision of a court within the United States and one or more United States persons have the authority to control all substantial decisions of the trust or (ii) that has a valid election in effect under applicable United States Treasury Regulations to be treated as a United States person.

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Dividends

We do not expect to pay any cash distributions on our common stock in the foreseeable future. However, if we do make a cash distribution on our common stock, such distributions will constitute dividends for U.S. federal income tax purposes to the extent paid from our current or accumulated earnings and profits, as determined under U.S. federal income tax principles. Distributions in excess of earnings and profits will constitute a return of capital that is applied against and reduces the non-United States holder s adjusted tax basis in the common stock, and any remaining excess will be treated as gain realized on the sale or other disposition of the common stock. See Gain on Disposition of Common Stock below for additional discussion of the federal tax treatment of distributions in excess of earnings and profits. Any distribution to a non-United States holder of common stock that is not effectively connected with a non-United States holder s conduct of a U.S. trade or business ordinarily will be subject to withholding of United States federal income tax at a rate of 30%, or such lower rate as may be specified under an applicable income tax treaty. To receive a reduced treaty rate, a non-United States holder must provide us with IRS Form W-8BEN or other appropriate version of Form W-8 certifying eligibility for the reduced rate.

Dividends paid to a non-United States holder that are effectively connected with a trade or business conducted by the non-United States holder in the United States (and, where a tax treaty applies, are attributable to a permanent establishment maintained by the non-United States holder in the United States) generally will be exempt from the withholding tax described above but instead will be subject to United States federal income tax on a net income basis at the regular graduated U.S. federal income tax rates in much the same manner as if the non-United States holder were a resident of the United States. In such cases, we will not have to withhold U.S. federal income tax if the non-United States holder complies with applicable certification and disclosure requirements. To claim this exemption from withholding tax, a non-United States holder must provide us with an IRS Form W-8ECI properly certifying eligibility for such exemption. Dividends received by a corporate non-United States holder that are effectively connected with a trade or business conducted by such corporate non-United States holder in the United States may also be subject to an additional branch profits tax at a rate of 30% or such lower rate as may be specified by an applicable tax treaty.

A non-United States holder that claims the benefit of an applicable income tax treaty generally will be required to satisfy applicable certification and other requirements. However,

- in the case of common stock held by a foreign partnership, the certification requirement generally will be applied to the partners of the partnership and the partnership will be required to provide certain information;

- in the case of common stock held by a foreign trust, the certification requirement generally will be applied to the trust or the beneficial owners of the trust depending on whether the trust is a foreign complex trust, foreign simple trust or foreign grantor trust as defined in the U.S. Treasury Regulations; and

- look-through rules will apply for tiered partnerships, foreign simple trusts and foreign grantor trusts.

A non-United States holder that is a foreign partnership or a foreign trust is urged to consult its own tax advisor regarding its status under these U.S. Treasury Regulations and the certification requirements applicable to it.

A non-United States holder that is eligible for a reduced rate of U.S. federal withholding tax under an income tax treaty may obtain a refund or credit of any excess amounts withheld by filing an appropriate claim for refund with the U.S. Internal Revenue Service.

Gain on Disposition of Common Stock

A non-United States holder generally will not be subject to U.S. federal income tax on any gain realized upon the sale or other disposition of our common stock unless:

the gain is effectively connected with the non-United States holder s conduct of a trade or business in the United States, and if required by an applicable tax treaty, attributable to a permanent establishment maintained by the non-United States holder in the United States;

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- the non-United States holder is a nonresident alien individual present in the United States for 183 days or more during the taxable year of the disposition and certain other requirements are met; or

- our common stock constitutes a U.S. real property interest by reason of our status as a United States real property holding corporation for U.S. federal income tax purposes (a USRPHC) at any time within the shorter of the five-year period preceding the disposition or your holding period for our common stock.

Unless an applicable tax treaty provides otherwise, gain described in the first bullet point above will be subject to U.S. federal income tax on a net income basis in the same manner as if such holder were a resident of the United States. Non-United States holders that are foreign corporations also may be subject to a branch profits tax equal to 30% (or such lower rate specified by an applicable tax treaty) of a portion of its effectively connected earnings and profits for the taxable year. Non-United States holders are urged to consult any applicable tax treaties that may provide for different rules.

Gain described in the second bullet point above will be subject to U.S. federal income tax at a flat 30% rate, but may be offset by U.S. source capital losses.

We believe that we are a USRPHC. Nonetheless, a non-United States holder generally will not be subject to United States federal income tax on any gain realized on a disposition of our common stock as a result of the third bullet point above if our common stock is considered to be regularly traded on an established securities market, within the meaning of Section 897 of the Code and the applicable Treasury Regulations, at any time during the calendar year in which the sale or other disposition occurs, and the non-United States holder does not actually or constructively own, at any time during the five-year period ending on the date of the sale or other disposition, more than 5% of our common stock. It is likely that our common stock will not be considered regularly traded on an established securities market prior to the effectiveness of the registration statement governing the resale of such stock. In addition, even after the registration statement becomes effective, it is possible that our common stock will not be considered regularly traded if it is not regularly quoted by brokers or dealers making a market in our common stock.

If our common stock is not considered to be regularly traded on an established securities market, a non-United States holder may be subject to withholding at a rate of 10% of the amount realized on a disposition of our common stock, and the non-United States holder generally will be taxed on its net gain derived from the disposition at the regular graduated U.S. federal income tax rates and in much the same manner as is applicable to U.S. persons. If the non-United States holder is a foreign corporation, the additional branch profits tax described above may also apply. Similarly, if we make any distribution to a non-United States holder in excess of our current and accumulated earnings and profits, the distribution generally will be subject to withholding in the manner described above under Dividends , and the non-United States holder generally will be taxed on its net gain, if any, derived from the receipt of the distribution at the regular U.S. federal income tax rates applicable to United States persons (subject to a credit for any tax withheld). If the non-United States holder subject to tax in this manner is a foreign corporation, the additional branch profits tax described above may also apply. A non-United States holder may obtain a refund or credit of any excess amounts withheld by filing an appropriate claim for refund with the U.S. Internal Revenue Service.

Non-United States holders should consult their own tax advisors with respect to the application of the foregoing rules to their ownership and disposition of our common stock.

Federal Estate Taxes

If you are an individual, common stock owned or treated as being owned by you at the time of your death will be included in your gross estate for United States federal estate tax purposes and may be subject to United States federal estate tax, unless an applicable estate tax treaty provides otherwise.

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Information Reporting and Backup Withholding

Generally, we must report annually to the IRS and to you the amount of dividends paid to you, your name and address, and the amount, if any, of tax withheld. Copies of the information returns reporting those dividends and amounts withheld may also be made available to the tax authorities in the country in which you reside under the provisions of any applicable tax treaty or exchange of information agreement.

In general, backup withholding at the applicable rate (currently 28%) will not apply to dividends on our common stock paid by us or our paying agents, in their capacities as such, to a non-United States holder if such non-United States holder has provided the required certification and neither we nor our paying agent has actual knowledge or reason to know that the payee is a United States person.

Information reporting and backup withholding generally will not apply to a payment of the proceeds of a sale of common stock effected outside the United States by a foreign office of a foreign broker. However, information reporting requirements will apply to a payment of the proceeds of a sale of common stock effected outside the United States by a foreign office of a broker if the broker (i) is a United States person, (ii) derives 50% or more of its gross income for certain periods from the conduct of a trade or business in the United States, (iii) is a controlled foreign corporation as to the United States, or (iv) is a foreign partnership that, at any time during its taxable year, is more than 50% (by income or capital interests) owned by United States persons or is engaged in the conduct of a trade or business in the United States, unless in any such case the broker has documentary evidence in its records that the beneficial owner is a non-United States holder and certain other conditions are met, or the holder otherwise establishes an exemption. Payment of the proceeds of a sale of common stock by a United States office of a broker will be subject to both information reporting and backup withholding unless the holder certifies its non-United States holder status under penalties of perjury, or otherwise establishes an exemption and the broker does not have actual knowledge or reason to know that the payee is a United States person.

Backup withholding is not an additional tax. Any amount withheld under the backup withholding rules will be allowed as a credit against the non-United States holder s United States federal income tax liability and any excess may be refundable if the proper information is provided to the IRS.

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UNDERWRITING

We are offering the shares of common stock described in this prospectus through a number of underwriters. Banc of America Securities LLC, A.G. Edwards & Sons, Inc. and Raymond James & Associates, Inc. are the representatives of the underwriters. We have entered into a firm commitment underwriting agreement with the representatives. Subject to the terms and conditions of the underwriting agreement, we have agreed to sell to the underwriters, and each underwriter has agreed to purchase, the number of shares of common stock listed next to its name in the following table:

Underwriter	Number of Shares
Banc of America Securities LLC	2,500,000
A.G. Edwards & Sons, Inc.	1,250,000
Raymond James & Associates, Inc.	1,250,000
Total	5,000,000

The underwriting agreement is subject to a number of terms and conditions and provides that the underwriters must buy all of the shares if they buy any of them. The underwriters will sell the shares to the public when and if the underwriters buy the shares from us.

The underwriters initially will offer the shares to the public at the price specified on the cover page of this prospectus. The underwriters may allow a concession of not more than $0.42 per share to selected dealers. If all the shares are not sold at the initial public offering price, the underwriters may change the public offering price and the other selling terms. The common stock is offered subject to a number of conditions, including:

receipt and acceptance of the common stock by the underwriters; and

the underwriters right to reject orders in whole or in part.

Option to Purchase Additional Shares. We have granted the underwriters an option to purchase up to 750,000 additional shares of our common stock at the same price per share as they are paying for the shares shown in the table above. These additional shares would cover sales by the underwriters which exceed the total number of shares shown in the table above. The underwriters may exercise this option at any time and from time to time, in whole or in part, within 30 days after the date of this prospectus. To the extent that the underwriters exercise this option, each underwriter will purchase additional shares from us in approximately the same proportion as it purchased the shares shown in the table above. We will pay the expenses associated with the exercise of the option.

Discount and Commissions. The following table shows the per share and total underwriting discounts and commissions to be paid to the underwriters by us. These amounts are shown assuming no exercise and full exercise of the underwriters option to purchase additional shares.

Paid by Us

	No Exercise	Full Exercise
Per Share	$ 0.70	$ 0.70
Total	$ 3,500,000	$ 4,025,000

We estimate that the expenses of the offering, not including underwriting discounts and commissions, will be approximately $850,000, all of which will be paid by us.

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Listing. Our common stock has been approved for listing on the Nasdaq Global Market under the symbol GMET.

Stabilization. In connection with this offering, the underwriters may engage in activities that stabilize, maintain or otherwise affect the price of our common stock, including:

- stabilizing transactions;
- short sales;
- syndicate covering transactions;
- imposition of penalty bids; and
- purchases to cover positions created by short sales.

Stabilizing transactions consist of bids or purchases made for the purpose of preventing or retarding a decline in the market price of our common stock while this offering is in progress. Stabilizing transactions may include making short sales of our common stock, which involves the sale by the underwriters of a greater number of shares of common stock than they are required to purchase in this offering, and purchasing shares of common stock from us or on the open market to cover positions created by short sales. Short sales may be covered shorts, which are short positions in an amount not greater than the underwriters option to purchase additional shares referred to above, or may be naked shorts, which are short positions in excess of that amount. Syndicate covering transactions involve purchases of our common stock in the open market after the distribution has been completed in order to cover syndicate short positions.

The underwriters may close out any covered short position either by exercising their option to purchase additional shares, in whole or in part, or by purchasing shares in the open market. In making this determination, the underwriters will consider, among other things, the price of shares available for purchase in the open market compared to the price at which the underwriters may purchase shares as referred to above.

A naked short position is more likely to be created if the underwriters are concerned that there may be downward pressure on the price of the common stock in the open market that could adversely affect investors who purchased in this offering. To the extent that the underwriters create a naked short position, they will purchase shares in the open market to cover the position.

The representatives also may impose a penalty bid on underwriters and dealers participating in the offering. This means that the representatives may reclaim from any syndicate members or other dealers participating in the offering the commissions and selling concessions on shares sold by them and purchased by the representatives in stabilizing or short covering transactions.

These activities may have the effect of raising or maintaining the market price of our common stock or preventing or retarding a decline in the market price of our common stock. As a result of these activities, the price of our common stock may be higher than the price that otherwise might exist in the open market. If the underwriters commence these activities, they may discontinue them at any time. The underwriters may carry out these transactions on the Nasdaq Global Market, in the over-the-counter market or otherwise.

In connection with this offering, some underwriters and any selling group members who are qualified market makers on the Nasdaq Global Market may engage in passive market making transactions in our common stock on the Nasdaq Global Market. Passive market making is allowed during the period when the SEC s rules would otherwise prohibit market activity by the underwriters and dealers who are participating in this offering. Passive market making may occur during the business day before the pricing of this offering, before the commencement of offers or sales of the common stock. A passive market maker must comply with applicable volume and price limitations and must be identified as a passive market maker. In general, a passive market

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maker must display its bid at a price not in excess of the highest independent bid for our common stock; but if all independent bids are lowered below the passive market maker s bid, the passive market maker must also lower its bid once it exceeds specified purchase limits. Net purchases by a passive market maker on each day are limited to a specified percentage of the passive market maker s average daily trading volume in our common stock during the specified period and must be discontinued when that limit is reached. Passive market making may cause the price of our common stock to be higher than the price that otherwise would exist in the open market in the absence of those transactions. The underwriters and dealers are not required to engage in a passive market making and may end passive market making activities at any time.

The underwriters have informed us that they do not expect to make sales to accounts over which they exercise discretionary authority in excess of 5% of the shares of common stock being offered.

IPO Pricing. Prior to this offering, there has been no public market for our common stock. The initial public offering price was negotiated between us and the representatives of the underwriters. Among the factors considered in these negotiations were:

- the history of, and prospects for, our company and the industry in which we compete;
- our past and present financial performance;
- an assessment of our management;
- the present state of our development;
- the prospects for our future earnings;
- the prevailing conditions of the applicable United States securities market at the time of this offering; and
- market valuations of publicly traded companies that we and the representatives of the underwriters believe to be comparable to us.

Qualified Independent Underwriter. Banc of America Securities LLC is a member of the NASD. Because we expect that more than 10% of the net proceeds of this offering will be paid to affiliates of Banc of America Securities LLC who are lenders under our credit facility, this offering is being conducted in accordance with the applicable requirements of Conduct Rule 2710(h)(1) and Conduct Rule 2720 of the NASD regarding the underwriting of securities of a company with which a member has a conflict of interest within the meaning of those rules. Conduct Rule 2720(c)(3) requires that the public offering price of an equity security must be no higher than the price recommended by a qualified independent underwriter which has participated in the preparation of the registration statement and performed its usual standard of due diligence in connection with that preparation. Raymond James & Associates, Inc. has agreed to act as qualified independent underwriter with respect of this offering. The public offering price of our common stock will be no higher than that recommended by Raymond James & Associates, Inc. Raymond James & Associates, Inc. will receive no additional compensation for acting in this capacity in connection with this offering, and we have agreed to indemnify Raymond James & Associates, Inc. in its capacity as qualified independent underwriter against certain liabilities under the Securities Act.

Lock-up Agreements. We and our directors and executive officers will enter into lock-up agreements with the underwriters. Under these agreements, subject to exceptions, we may not issue any new shares of common stock, and those holders of stock may not, directly or indirectly, offer, sell, contract to sell, pledge or otherwise dispose of or hedge any common stock or securities convertible into or exchangeable for shares of common stock, or publicly announce the intention to do any of the foregoing, without the prior written consent of Banc of America Securities LLC for a period of 180 days from the date of this prospectus. This consent may be given at any time without public notice. In addition, during this 180-day period, we will also agree not to file any registration statement for, and each of our officers and stockholders will agree not to make any demand for, or exercise any right of, the registration of, any shares of common stock or any securities convertible into or exercisable or exchangeable for common stock without the prior written consent of Banc of America Securities LLC, except for registration statements on Form S-8 to register shares issued pursuant to our stock option or stock incentive plans.

The 180-day restricted period described above is subject to extension such that, in the event that either (1) during the last 17 days of the 180-day restricted period, we issue an earnings release or material news or a material event related to us occurs or (2) prior to the expiration of the 180-day restricted period, we announce that we will release earnings results during the 16-day period beginning on the last day of the 180-day period, the lock-up restrictions described above will continue to apply until the expiration of the 18-day period beginning on the earnings release or the occurrence of the material news or material event.

The holders of shares of our common stock that are beneficiaries of the registration rights agreement and have elected not to participate in this offering also will not be able to sell any shares owned by them for a period of 60 days following the effective date of the registration statement, of which this prospectus is a part.

We have been informed by Banc of America Securities LLC that they have no present intention to consent to the release of the lock-up restrictions described above.

Directed Share Program. At our request, the underwriters have reserved for sale to certain of our employees, directors, families of employees and directors, business associates and other third parties at the initial public offering price up to 10% of the shares being offered by this prospectus. The sale of the reserved shares to these purchasers will be made by Raymond James & Associates, Inc. The purchasers of these shares will be subject to a 60-day lock-up or as required by the Conduct Rules of the NASD, which require a 90-day lock-up if they are affiliated with or associated with NASD members or if they or members of their immediate families hold senior positions at financial institutions, or to the extent the purchasers are subject to a lock-up agreement with the underwriters as described above. We do not know if our employees, directors, families of employees and directors, business associates and other third parties will choose to purchase all or any portion of the reserved shares, but any purchases they do make will reduce the number of shares available to the general public. If all of these reserved shares are not purchased, the underwriters will offer the remainder to the general public on the same terms as the other shares offered by this prospectus.

Indemnification. We will indemnify the underwriters against some liabilities, including liabilities under the Securities Act. If we are unable to provide this indemnification, we will contribute to payments the underwriters may be required to make in respect of those liabilities.

Electronic Prospectuses. A prospectus in electronic format may be made available on the web sites maintained by one or more of the underwriters participating in this offering. Other than the prospectus in electronic format, the information on any such web site, or accessible through any such web site, is not part of the prospectus. The representatives may agree to allocate a number of shares to underwriters for sale to their online brokerage account holders. Internet distributions will be allocated by the underwriters that will make internet distributions on the same basis as other allocations. In addition, shares may be sold by the underwriters to securities dealers who resell shares to online brokerage account holders.

Conflicts/Affiliates. The underwriters and their affiliates have provided, and may in the future provide, various investment banking, commercial banking and other financial services for us for which services they have received, and may in the future receive, customary fees. Bank of America, N.A., an affiliate of Banc of America Securities LLC, is the agent under our credit facility.

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Selling Restrictions. Each underwriter intends to comply with all applicable laws and regulations in each jurisdiction in which it acquires, offers, sells or delivers the shares or has in its possession or distributes the Prospectus or any other material.

In relation to each Member State of the European Economic Area which has implemented the Prospectus Directive (each, a Relevant Member State), with effect from and including the date on which the Prospectus Directive is implemented in that Relevant Member State (the Relevant Implementation Date) an offer of the shares to the public may not be made in that Relevant Member State prior to the publication of a prospectus in relation to the shares which has been approved by the competent authority in that Relevant Member State or, where appropriate, approved in another Relevant Member State and notified to the competent authority in that Relevant Member State, all in accordance with the Prospectus Directive, except that it may, with effect from and including the Relevant Implementation Date, make an offer of shares to the public in that Relevant Member State at any time:

(a) to legal entities which are authorised or regulated to operate in the financial markets or, if not so authorised or regulated, whose corporate purpose is solely to invest in securities;

(b) to any legal entity which has two or more of (1) an average of at least 250 employees during the last financial year; (2) a total balance sheet of more than 43,000,000 and (3) an annual net turnover of more than 50,000,000, as shown in its last annual or consolidated accounts; or

(c) in any other circumstances which do not require the publication by the us of a prospectus pursuant to Article 3 of the Prospectus Directive.

For the purposes of this provision, the expression an offer of shares to the public in relation to any shares in any Relevant Member State means the communication in any form and by any means of sufficient information on the terms of the offer and the shares to be offered so as to enable an investor to decide to purchase or subscribe the shares, as the same may be varied in that Member State by any measure implementing the Prospectus Directive in that Member State and the expression Prospectus Directive means Directive 2003/71/EC and includes any relevant implementing measure in each Relevant Member State.

No prospectus (including any amendment, supplement or replacement thereto) has been prepared in connection with the offering of the shares that has been approved by the Autorité des marchés financiers or by the competent authority of another State that is a contracting party to the Agreement on the European Economic Area and notified to the Autorité des marchés financiers; no shares have been offered or sold and will be offered or sold, directly or indirectly, to the public in France except to permitted investors (Permitted Investors) consisting of persons licensed to provide the investment service of portfolio management for the account of third parties, qualified investors (investisseurs qualifiés) acting for their own account and/or investors belonging to a limited circle of investors (cercle restreint d investisseurs) acting for their own account, with qualified investors and limited circle of investors having the meaning ascribed to them in Articles L. 411-2, D. 411-1, D. 411-2, D. 734-1, D. 744-1, D. 754-1 and D. 764-1 of the French Code Monétaire et Financier and applicable regulations thereunder; none of this prospectus or any other materials related to the offering or information contained therein relating to the shares has been released, issued or distributed to the public in France except to Permitted Investors; and the direct or indirect resale to the public in France of any shares acquired by any Permitted Investors may be made only as provided by Articles L. 411-1, L. 411-2, L. 412-1 and L. 621-8 to L. 621-8-3 of the French Code Monétaire et Financier and applicable regulations thereunder.

Each underwriter acknowledges and agrees that:

(i) it has not offered or sold and will not offer or sell the shares other than to persons whose ordinary activities involve them in acquiring, holding, managing or disposing of investments (as principal or as agent) for the purposes of their businesses or who it is reasonable to expect will acquire, hold, manage or dispose of investments (as principal or agent) for the purposes of their businesses where the issue of the shares would otherwise constitute a contravention of Section 19 of the Financial Services and Markets Act 2000 (the FSMA) by us;

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(ii) it has only communicated or caused to be communicated and will only communicate or cause to be communicated an invitation or inducement to engage in investment activity (within the meaning of Section 21 of the FSMA) received by it in connection with the issue or sale of the shares in circumstances in which Section 21(1) of the FSMA does not apply to us; and

(iii) it has complied and will comply with all applicable provisions of the FSMA with respect to anything done by it in relation to the shares in, from or otherwise involving the United Kingdom.

This document is only being distributed to and is only directed at (i) persons who are outside the United Kingdom or (ii) to investment professionals falling within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (the Order) or (iii) high net worth entities, and other persons to whom it may lawfully be communicated, falling within Article 49(2)(a) to (d) of the Order (all such persons together being referred to as relevant persons). The shares are only available to, and any invitation, offer or agreement to subscribe, purchase or otherwise acquire such shares will be engaged in only with, relevant persons. Any person who is not a relevant person should not act or rely on this document or any of its contents.

The offering of the shares of common stock has not been cleared by the Italian Securities Exchange Commission (Commissione Nazionale per le Società e la Borsa, the CONSOB) pursuant to Italian securities legislation and, accordingly, has represented and agreed that the shares of common stock may not and will not be offered, sold or delivered, nor may or will copies of the prospectus or any other documents relating to the shares of common stock be distributed in Italy, except (i) to professional investors (operatori qualificati), as defined in Article 31, second paragraph, of CONSOB Regulation No. 11522 of July 1, 1998, as amended, (the Regulation No. 11522), or (ii) in other circumstances which are exempted from the rules on solicitation of investments pursuant to Article 100 of Legislative Decree No. 58 of February 24, 1998 (the Financial Service Act) and Article 33, first paragraph, of CONSOB Regulation No. 11971 of May 14, 1999, as amended.

Any offer, sale or delivery of the shares of common stock or distribution of copies of the prospectus or any other document relating to the shares of common stock in Italy may and will be effected in accordance with all Italian securities, tax, exchange control and other applicable laws and regulations, and, in particular, will be: (i) made by an investment firm, bank or financial intermediary permitted to conduct such activities in Italy in accordance with the Financial Services Act, Legislative Decree No. 385 of September 1, 1993, as amended (the Italian Banking Law), Regulation No. 11522, and any other applicable laws and regulations; (ii) in compliance with Article 129 of the Italian Banking Law and the implementing guidelines of the Bank of Italy; and (iii) in compliance with any other applicable notification requirement or limitation which may be imposed by CONSOB or the Bank of Italy.

Any investor purchasing shares of our common stock in the offering is solely responsible for ensuring that any offer or resale of the shares of common stock it purchased in the offering occurs in compliance with applicable laws and regulations.

The prospectus and the information contained therein are intended only for the use of its recipient and, unless in circumstances which are exempted from the rules on solicitation of investments pursuant to Article 100 of the Financial Service Act and Article 33, first paragraph, of CONSOB Regulation No. 11971 of May 14, 1999, as amended, is not to be distributed, for any reason, to any third party resident or located in Italy. No person resident or located in Italy other than the original recipients of this document may rely on it or its content.

In addition to the above (which shall continue to apply to the extent not inconsistent with the implementing measures of the Prospectus Directive in Italy), after the implementation of the Prospectus Directive in Italy, the restrictions, acknowledgments and agreements in the paragraph relating to the European Economic Area set forth above shall apply to Italy.

Insofar as the requirements above are based on laws which are superseded at any time pursuant to the implementation of the Prospectus Directive, such requirements shall be replaced by the applicable requirements under the Prospectus Directive.

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LEGAL MATTERS

The validity of the shares offered hereby and certain other legal matters in connection with this offering will be passed upon for us by Thompson & Knight LLP, Houston, Texas. Certain legal matters in connection with the shares of common stock offered hereby will be passed upon for the underwriters by Vinson & Elkins L.L.P., Houston, Texas.

EXPERTS

The financial statements as of December 31, 2005 and 2004, and for each of the three years in the period ended December 31, 2005 included in this prospectus have been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the adoption of SFAS 143, Accounting for Asset Retirement Obligations) appearing in this registration statement, and has been so included in reliance upon the report of such firm given upon their authority as experts in accounting and auditing.

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 estimated proved reserves as of December 31, 2005 is attached to this prospectus as Appendix A. These estimates are included in this prospectus in reliance upon the authority of the firm as experts in these matters.

WHERE YOU CAN FIND MORE 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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GLOSSARY OF NATURAL GAS AND COALBED METHANE TERMS

The following is a description of the meanings of some of the oil and gas industry terms used in this prospectus.

Additional drilling locations. Locations specifically identified and scheduled by management as an estimate of our future multi-year drilling activities on existing acreage.

Appalachian Basin. A mountainous region in the eastern United States, running from northern Alabama to Pennsylvania, and including parts of Georgia, South Carolina, North Carolina, Tennessee, Kentucky, Virginia, and all of West Virginia.

Bcf. Billion cubic feet of natural gas.

Btu or British Thermal Unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

CBM. Coalbed methane.

CBM acres. Acreage under a lease that excludes oil, gas, and all other minerals other than CBM.

Coal seam. A single layer or stratum of coal.

Coal rank. Coal is a carbon rich rock derived from plant material accumulated in peat swamps. With increasing depth of burial, the plant material undergoes coalification, releasing volatile matter. The coal rank increases as the percentage of volatile mater (%VM) decreases. The generation of methane is a result of the thermal maturation or increasing rank of the coal. Coals targeted for CBM projects, from low rank to high rank, are lignite, sub-bituminous, high volatile bituminous, medium volatile bituminous and low volatile bituminous coals. The range of %VM associated with these coal ranks decrease from lignite at approximately 60%VM to low volatile bituminous coals at approximately 15%VM.

Completion. The installation of permanent equipment for the production of oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Development well. A well drilled within the proved boundaries of an oil or natural gas reservoir with the intention of completing the stratigraphic horizon known to be productive.

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Estimated proved reserves. The estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Estimated proved undeveloped reserves. Estimated proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Exploratory well. A well drilled to find and produce oil or gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir or to extend a known reservoir.

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Field. An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Finding and development costs. A performance measure, expressed in dollars per Mcf, commonly used throughout the oil and gas industry to measure the efficiency of a company in adding new reserves. The finding and development cost measure referred to in this prospectus is calculated for the three year time period by taking the sum of the cost incurred for exploration, development, and acquisition, including future development costs attributable to proved undeveloped reserves, adjusted for the change for the period in the balance of unevaluated gas properties not subject to amortization and dividing such amount by the total proved reserve additions. Management believes that this information is useful to an investor in evaluating GeoMet because it measures the efficiency of a company in adding proved reserves as compared to others in the industry. The cost and reserve information is derived directly from line items disclosed in the schedule of Capitalized Cost, Natural Gas Reserves and the Standardized Measure, which are all required to be disclosed by SFAS 69.

Gas desorption test. A process to estimate the volume of natural gas adsorbed in a volume of coal (usually expressed as cubic feet per ton) by placing a sample of coal into a sealed canister and taking periodic measurements of gas desorbed, temperature and pressure for up to 90 days. The estimate of total gas adsorbed in the coal sample is the sum of: (i) the measurements of gas during the test period, corrected to standard temperature and pressure (the measured gas), (ii) the lost gas, which is calculated using the elapsed time the sample desorbed before its placement into the canister and the rate of desorption determined from the test period, and (iii) the remaining gas, which is determined by measuring the gas released while grinding the coal sample into a powder or which is calculated mathematically using the measurements from the test period.

Gathering system. Pipelines and other equipment used to move natural gas from the wellhead to the trunk or the main transmission lines of a pipeline system.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Mcf. Thousand cubic feet of natural gas.

MMBtu. Million British thermal units.

MMcf. Million cubic feet of natural gas.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or well, as the case may be.

NYMEX. The New York Mercantile Exchange.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Proved developed reserves. Estimated proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.

PV-10 or present value of estimated future net revenues. An estimate of the present value of the estimated future net revenues from estimated proved natural gas reserves at a date indicated 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% in accordance with the SEC s practice, to determine their present value. The present value is shown to indicate the effect of time on the value of the revenue stream and should not be construed as being the fair market value of the

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properties. Estimates of future net revenues are made using oil and natural gas prices and operating costs at the date indicated and held constant for the life of the reserves.

Reserve life index. This index is calculated by dividing total estimated proved reserves by the production from the previous year to estimate the number of years of remaining production.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Shut in. Stopping an oil or gas well from producing.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or gas regardless of whether or not such acreage contains estimated proved reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production.

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GEOMET, INC. AND SUBSIDIARIES

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have audited the accompanying consolidated balance sheets of GeoMet, Inc. (the Company) as of December 31, 2005 and 2004 and the related consolidated statements of operations, stockholders equity and comprehensive income and cash flows for each of the three years in the period ended December 31, 2005. These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of GeoMet, Inc. as of December 31, 2005 and 2004, and the results of its operations and cash flows for each of the three years in the period ended December 31, 2005 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 4 to the Consolidated Financial Statements, the Company adopted Statement of Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*, on January 1, 2003.

/s/ DELOITTE & TOUCHE LLP

Houston, TX

April 12, 2006

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GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2005	December 31, 2004
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 615,806	$ 3,013,723
Restricted cash		130,243
Accounts receivable	5,577,140	3,484,560
Current portion of notes receivable	310,210	22,347
Derivative asset		440,585
Deferred tax asset	2,911,808	
Other current assets	414,232	404,610
Total current assets	9,829,196	7,496,068
Gas Properties utilizing the full cost method of accounting:		
Proved gas properties	229,519,222	131,190,981
Unevaluated gas properties, not subject to amortization	20,680,712	11,079,258
Other property and equipment	1,841,056	1,643,934
Total property and equipment	252,040,990	143,914,173
Less accumulated depreciation, depletion, and amortization	(15,392,300)	(10,376,533)
Property and equipment net	236,648,690	133,537,640
Other noncurrent assets:		
Note receivable	323,879	348,145
Note receivable from officer		250,000
Other	1,107,234	458,442
Total other noncurrent assets	1,431,113	1,056,587
TOTAL ASSETS	$ 247,908,999	$ 142,090,295
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Accounts payable	$ 6,861,075	$ 7,532,995
Derivative liability	8,931,926	
Asset retirement liability	51,510	280,569
Accrued liabilities	1,265,989	844,429
Current portion of long-term debt	86,472	89,392
Total current liabilities	17,196,972	8,747,385
Long-term debt	99,926,378	51,512,799

Long-term derivative liability	2,611,592	
Asset retirement liability	1,838,663	888,758
Other long-term accrued liabilities	258,573	303,294
Deferred income taxes	30,654,545	12,411,885
Total liabilities	152,486,723	73,864,121
Minority interest		2,534,395
Commitments and Contingencies (Note 12)		
Stockholders Equity:		
Common stock, $0.001 par value authorized 40,000,000, and 24,000,000 shares; issued and outstanding 29,974,664 and 24,000,000 at December 31, 2005 and December 31, 2004, respectively	29,975	24,000
Paid-in capital	106,408,915	59,848,451
Accumulated other comprehensive income	56,310	2,119
Retained earnings	6,443,928	11,017,209
Less notes receivable	(17,516,852)	(5,200,000)
Total stockholders equity	95,422,276	65,691,779
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 247,908,999	$ 142,090,295

See accompanying Notes to Consolidated Financial Statements.

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GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

AND COMPREHENSIVE INCOME

	Years Ended December 31,		
	2005	**2004**	**2003**
Revenues:			
Gas sales	$ 41,604,342	$ 19,521,447	$ 11,700,119
Operating fees and other	375,509	1,402,334	348,917
Total revenues	41,979,851	20,923,781	12,049,036
Expenses:			
Lease operating expense	8,687,550	5,091,046	1,639,679
Compression and transportation expense	3,332,045	1,951,316	992,634
Production taxes	913,885	473,222	413,799
Depreciation, depletion and amortization	4,867,134	2,691,320	2,120,038
Research and development	608,477	278,339	431,560
General and administrative	3,207,992	2,513,297	1,370,908
Impairment of other equipment and other non-current assets			8,394
Realized losses on derivative contracts	7,473,004	814,940	44,160
Unrealized losses (gains) from the change in market value of open derivative contracts	12,059,208	(542,076)	101,491
Total operating expenses	41,149,295	13,271,404	7,122,663
Income from operations	830,556	7,652,377	4,926,373
Other income (expense):			
Interest income	76,569	69,553	94,409
Interest expense (net of amounts capitalized)	(3,894,550)	(985,949)	(231,734)
Other expenses	(21,366)	(4,174)	(6,908)
Total other income (expense)	(3,839,347)	(920,570)	(144,233)
Income (loss) before income taxes, minority interest, and cumulative effect of change in accounting principle, net of income tax	(3,008,791)	6,731,807	4,782,140
Income tax (benefit) expense	(993,174)	2,312,008	1,650,928
Net income (loss) before minority interest and cumulative effect of change in accounting principle, net of income tax	(2,015,617)	4,419,799	3,131,212
Minority interest	(442,336)	584,018	570,719
Net income (loss) before cumulative effect of change in accounting principle, net of income tax	(1,573,281)	3,835,781	2,560,493
Cumulative effect of change in accounting principle, net of income tax			19,075

Net income (loss)	(1,573,281)	3,835,781	2,541,418
Other comprehensive income			
Foreign currency translation adjustment, net of income tax of $0	54,191	2,119	
Comprehensive income (loss)	$ (1,519,090)	$ 3,837,900	$ 2,541,418
Earnings per common share:			
Basic			
Income (loss) before cumulative effect of change in accounting principle, net of income tax	$ (0.06)	$ 0.17	$ 0.20
Cumulative effect of change in accounting principle, net of income tax			
Net income (loss) per share basic	$ (0.06)	$ 0.17	$ 0.20
Diluted			
Income (loss) before cumulative effect of change in accounting principle, net of income tax	$ (0.06)	$ 0.17	$ 0.20
Cumulative effect of change in accounting principle, net of income tax			
Net income (loss) per share diluted	$ (0.06)	$ 0.17	$ 0.20
Weighted average number of common shares:			
Basic	28,164,946	22,710,384	12,668,492
Diluted	28,164,946	22,860,396	12,668,492

See accompanying Notes to Consolidated Financial Statements.

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GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

AND COMPREHENSIVE INCOME

	December 31,		
	2005	2004	2003
Common stock, $0.001 par value shares outstanding:			
Balance at beginning of year	24,000,000	20,000,000	8,000,000
Sale of common stock to existing shareholders		4,000,000	12,000,000
Exercise of options, under merger agreement with majority-owned subsidiary	1,456,668		
Exercise of stock options, under incentive stock option plan	79,228		
Common stock issued to acquire non-controlling interest in majority-owned subsidiary	4,438,768		
Balance at end of year	29,974,664	24,000,000	20,000,000
Common stock, $0.001 par value:			
Balance at beginning of year	$ 24,000	$ 20,000	$ 8,000
Sale of common stock to existing shareholders		4,000	12,000
Exercise of options, under merger agreement with majority-owned subsidiary	1,457		
Exercise of stock options, under incentive stock option plan	79		
Common stock issued to acquire non-controlling interest in majority-owned subsidiary	4,439		
Balance at end of year	$ 29,975	$ 24,000	$ 20,000
Paid-in capital:			
Balance at beginning of year	$ 59,848,451	$ 49,852,450	$ 19,864,450
Sale of common stock to existing shareholders		9,996,001	29,988,000
Exercise of options, under merger agreement with majority-owned subsidiary	11,131,068		
Exercise of stock options, under incentive stock option plan	98,840		
Common stock issued to acquire non-controlling interest in majority-owned subsidiary	33,918,848		
Accrued interest on all notes receivable issued to purchase common stock	1,411,708		
Balance at end of year	$ 106,408,915	$ 59,848,451	$ 49,852,450
Accumulated other comprehensive income:			
Balance at beginning of year	$ 2,119	$	$
Foreign currency translation adjustment, net of income tax of $0	54,191	2,119	
Balance at end of year	$ 56,310	$ 2,119	$
Retained earnings:			
Balance at beginning of year	$ 11,017,209	$ 7,181,428	$ 4,640,010

Common stock dividends ($0.125 per share)	(3,000,000)		
Net income (loss)	(1,573,281)	3,835,781	2,541,418
Balance at end of year	$ 6,443,928	$ 11,017,209	$ 7,181,428
Notes receivable:			
Balance at beginning of year	$ (5,200,000)	$ (4,300,000)	$ (1,600,000)
Common stock issued	(10,905,144)	(900,000)	(2,700,000)
Accrued interest on all notes receivable issued to purchase common stock	(1,411,708)		
Balance at end of year	$ (17,516,852)	$ (5,200,000)	$ (4,300,000)
Total Stockholders Equity	$ 95,422,276	$ 65,691,779	$ 52,753,878

See accompanying Notes to Consolidated Financial Statements.

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GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2005	**2004**	**2003**
Cash flows provided by operating activities:			
Net income (loss)	$ (1,573,281)	$ 3,835,781	$ 2,541,418
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:			
Depreciation, depletion and amortization	5,015,767	2,773,602	2,182,984
Minority interest	(442,336)	584,018	570,719
Deferred income taxes	(1,001,946)	2,247,008	1,625,928
Impairment			8,394
Unrealized losses (gains) from the change in market value of open derivative contracts (including premium amortization)	12,059,208	(413,976)	155,191
Other noncash charges	269,423	164,683	98,710
Changes in operating assets and liabilities:			
Accounts receivable	(2,078,553)	(968,287)	(541,894)
Income tax refund receivable			1,183,807
Other current assets	(9,612)	(36,032)	(52,951)
Accounts payable	(184,511)	2,134,223	2,667,271
Accrued income tax payable	(40,000)		
Other accrued liabilities	418,679	259,944	361,133
Net cash provided by operating activities	12,432,838	10,580,964	10,800,710
Cash flows used in investing activities:			
Capital expenditures	(59,817,472)	(86,189,138)	(36,068,945)
Proceeds from sale of properties	6,739	21,418,809	
Purchase of GeoMet, Inc. common stock from minority stockholder		(1,401,250)	
Loan to officer			(250,000)
Restricted cash	130,243	(42,103)	(38,140)
Other assets	19,204	20,495	15,890
Net cash used in investing activities	(59,661,286)	(66,193,187)	(36,341,195)
Cash flows provided by financing activities:			
Debt issuance costs	(114,882)	(275,993)	(169,709)
Proceeds from exercise of stock options	326,298		
Equity offering costs	(716,443)		
Proceeds from sales of common stock		9,100,000	27,300,000
Credit facility borrowings	72,500,000	122,500,000	35,000,000
Common stock dividend	(3,000,000)		
Payments on credit facility and other debt	(24,089,392)	(81,131,937)	(31,596,143)
Net cash provided by financing activities	44,905,581	50,192,070	30,534,148
Effect of exchange rate changes on cash	(75,050)	(3,786)	

Increase (decrease) in cash and cash equivalents	(2,397,917)	(5,423,939)	4,993,663
Cash and cash equivalents at beginning of year	3,013,723	8,437,662	3,443,999
Cash and cash equivalents at end of year	$ 615,806	$ 3,013,723	$ 8,437,662
Supplemental disclosure of cash flow information			
Cash paid during the year for:			
Interest	$ 4,214,028	$ 861,874	$ 251,789
Income taxes	$ 175,000	$ 25,000	$ 25,000
Issuance of common stock in exchange for note receivable	$ 10,905,144	$ 900,000	$ 2,700,000
Issuance of common stock in exchange for majority-owned subsidiary s minority interest	$ 33,923,287	$	$
Acquisition of asset through a capital lease	$	$	$ 98,066

See accompanying Notes to Consolidated Financial Statements.

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GEOMET, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 Organization and Our Business

GeoMet, Inc. (GeoMet) (formerly GeoMet Resources, Inc.) was incorporated under the laws of the state of Delaware on November 9, 2000. GeoMet is an independent natural gas producer involved in the exploration, development and production of natural gas from coal seams (coalbed methane). Our principal operations and producing properties are located in Alabama, West Virginia, and Virginia. GeoMet operates in one segment, natural gas exploration, development and production, almost exclusively within the continental United States.

Effective January 24, 2006, GeoMet s Board of Directors approved a four-for-one common stock split. Therefore, all share data in the financial statements and notes thereto has been adjusted for this split.

On April 13, 2005, GeoMet acquired, through a stock exchange, the minority interest in its 81% owned subsidiary and merged the subsidiary into GeoMet. Following the merger, GeoMet changed its name from GeoMet Resources, Inc. to GeoMet, Inc. In connection with this transaction, GeoMet exchanged 4,438,768 shares of its common stock valued at $7.64 per share for all of the common stock of the subsidiary that it did not already own, approximately 19.05%. The acquisition was accounted for as a purchase in accordance with SFAS No. 141, *Business Combinations* whereby the purchase price of the net assets acquired was allocated to those net assets based on their fair value. No goodwill was recorded because the purchase price approximated the fair value of net assets acquired. The exchange value was determined through negotiations between a special committee of the 81% owned subsidiary s board of directors and management.

The following table summarizes the estimated fair values of the assets acquired and liabilities assumed at the merger date. As of December 31, 2005, the purchase price allocation has not been finalized. An evaluation of unproved properties and certain intangible assets is expected to be completed by March 31, 2006.

	April 13, 2005 (Fair Value)
Natural gas properties and equipment	$ 48,229,135
Minority interest	2,092,058
Deferred tax liability	(16,397,906)
Net assets acquired	$ 33,923,287

The following table reflects the unaudited pro forma results of operations as though the acquisition had been consummated at the beginning of the years presented.

	Years Ended December 31,	
	2005	2004
Revenues and other income	$ 41,979,851	$ 20,923,781
Net income (loss) before cumulative effect of change in accounting principle, net of tax	(2,169,338)	(3,938,465)
Net income (loss)	(2,169,338)	3,938,465
Net income (loss) per share:		
Basic	$ (0.08)	$ 0.15
Diluted	(0.08)	$ 0.15

On November 17, 2004, GeoMet acquired 0.95% of the common stock of its 80% owned subsidiary from a minority interest shareholder in a business combination accounted for as a purchase. The purchase price of $1,401,250 was paid in cash. The total fair value of $1,996,719 was allocated to proved properties. The

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GEOMET, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

acquisition was accounted for as a step acquisition in accordance with SFAS No. 141, *Business Combinations*, whereby the purchase price of the net assets acquired was allocated to those net assets based on their fair value.

Note 2 Summary of Significant Accounting Policies

Principles of Consolidation The Consolidated Financial Statements include the accounts of the Company and its subsidiaries, GeoMet Operating Company, Inc. and Hudson s Hope Gas, Ltd. For the year ended December 31, 2004, the consolidated financial statements include the accounts of GeoMet and its 81% owned subsidiary. For the year ended December 31, 2003 the consolidated financial statements include the accounts of GeoMet and its 80% owned subsidiary. For the year ended December 31, 2004 and 2003 the equity of the minority interests in its majority-owned subsidiary is shown in the consolidated financial statements as minority interests. All intercompany accounts and transactions have been eliminated in consolidation.

Use of Estimates in the Preparation of Financial Statements The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Our most significant financial estimates are based on remaining proved gas reserves. Estimates of proved gas reserves are key components of our depletion rate for natural gas properties, our unevaluated properties and our full cost ceiling test limitation. In addition, estimates are used in computing taxes, asset retirement obligations and fair value of derivative contracts. Actual results could differ from these estimates.

Business Segment Reporting

The Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) 131, Disclosures about Segments of an Enterprise and Related Information establishes standards for reporting information about operating segments. Operating segments are defined as components of an enterprise that engage in activities from which it may earn revenues and incur expenses. Separate financial information is available and this information is regularly evaluated by the chief decision maker for the purpose of allocating resources and assessing performance.

Segment reporting is not applicable for us as each of our operating areas has similar economic characteristics and each meets the criteria for aggregation as defined in SFAS 131. All of our operations involve the exploration, development and production of natural gas and are almost exclusively located within the continental United States. We have a single, company-wide management team that administers all properties as a whole rather than as discrete operating segments. We track only basic operational data by area. We do not maintain separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis. Throughout the year, we freely allocate capital resources on a project-by-project basis across our entire asset base to maximize profitability without regard to individual areas or segments.

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.

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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. See Supplemental Financial and Operating Information after Notes to Consolidated Financial Statements for a summary by year of unevaluated costs.

Asset Retirement Liability The Company adopted SFAS No. 143, *Accounting for Asset Retirement Obligations* effective January 1, 2003. It establishes accounting and reporting standards for retirement obligations associated with tangible long- lived assets that result from the legal obligation to plug, abandon and dismantle existing wells and facilities that it has acquired, constructed or developed. It requires that the fair value of the liability for asset retirement obligations be recognized in the period in which it is 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. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset.

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Other Property and Equipment The cost of other property and equipment is depreciated over the estimated useful lives of the related assets. The cost of leasehold improvements is depreciated over the lesser of the length of the related leases or the estimated useful lives of the assets. Depreciation is computed on the straight-line basis over the following estimated useful lives which range from three to seven years.

Furniture and fixtures	7 years
Automobiles	3 years
Machinery and equipment	5 years
Software and computer equipment	3 years

Cash and Cash Equivalents For purposes of these statements, short-term investments, which have an original maturity of three months or less, are considered cash equivalents.

Notes Receivable Included in Stockholders Equity The Company has loaned money to officers and employees to purchase common stock in the Company. Such amounts, including accrued interest, are recorded as Notes Receivable, and are included as a component of Stockholders Equity. See Note 15 for additional information regarding repayment.

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 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.

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Net Income (Loss) Per Common Share Basic earnings per share is calculated by dividing net income by the weighted average number of shares of common stock outstanding during the period. No dilution for any potentially dilutive securities is included. Fully diluted earnings per share assumes the conversion of all potentially dilutive securities and is calculated by dividing net income by the sum of the weighted average number of shares of common stock outstanding plus potentially dilutive securities. Dilutive earnings per share considers the impact of potentially dilutive securities except in periods in which there is a loss because the inclusion of the potential common shares would have an anti-dilutive effect. A reconciliation of the numerator and denominator is as follows:

	Years Ended December 31,		
	2005	**2004**	**2003**
Numerator			
Income (loss) available to common stockholders before cumulative effect of change in accounting principle, net of income tax	$ (1,573,281)	$ 3,835,781	$ 2,560,493
Cumulative effect of change in accounting principle, net of income tax			19,075
Net income (loss) available to common stockholders basic EPS	$ (1,573,281)	$ 3,835,781	$ 2,541,418
Effect of dilutive securities:			
Effect on minority interest from exercise of options to acquire subsidiary common stock		(70,023)	(7,564)
Net income (loss) available to common stockholders diluted EPS	$ (1,573,281)	$ 3,765,758	$ 2,533,854
Denominator			
Weighted average shares outstanding	28,164,946	22,710,384	12,668,492
Add dilutive securities:			
Stock Options		150,012	
Total weighted average shares outstanding and dilutive securities	28,164,946	22,860,396	12,668,492

For diluted earnings per share for the year ended December 31, 2005, because we reported a net loss, the effect of outstanding options to purchase 2,093,324 shares for this period were excluded from the calculation because the effect would be anti-dilutive. For the year ended December 31, 2003, the calculation of shares outstanding for diluted earnings per share does not include the effect of outstanding stock options to purchase 1,000,000 shares, because the exercise price of these options was greater than the average stock price for the year, which would have an antidulitive effect on earnings per share.

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 and risk of loss is transferred based on our net revenue interests. Gas sold in production operations is not significantly different from the Company s share of production based on its interest in the properties.

Concentrations of Market Risk The future results of the Company will be affected by the market price of natural gas. The availability of a ready market for natural gas will depend on numerous factors beyond the control of the Company, including weather, production of natural gas, imports, marketing, competitive fuels, proximity of natural gas pipelines and other transportation facilities, any oversupply or undersupply of natural gas, the regulatory environment, and other regional and political events, none of which can be predicted with certainty.

Concentration of Credit Risk Financial instruments, which subject the Company to concentrations of credit risk, consist primarily of cash and accounts receivable. The Company places its cash investments with

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highly qualified financial institutions. Risks with respect to receivables as of December 31, 2005 and 2004 arise substantially from the sales of natural gas. Management does not expect there to be any significant risk of collectability of this receivable and therefore has not provided for an allowance for doubtful accounts. See Note 12 for further discussion about our major customers.

Fair Value of Financial Instruments The fair value of cash and cash equivalents, current receivables and payables, approximate book value because of the short maturity of these accounts. Debt outstanding under the credit facility is variable rate debt and as such, approximates fair value, as interest rates are variable based on market rates. The outstanding note receivable in Other Non-Current Assets and certain Other Debt carries a fixed interest rate. See Notes 3 and 6 for the fair values of the receivable and other debt.

Operating Fees The Company has received fees from operating coalbed methane gas fields from other owners. Where we have conducted contract operations in fields where we do not own a working interest the fees are recognized in Revenues. Where we have conducted contract operations in fields where we own a working interest the fees reduce General and Administrative Expenses. These fees were recognized in the period in which the services were performed.

Capitalized General and Administrative Expenses Under the full cost method of accounting, a portion of our general and administrative expenses that are directly attributable to our acquisition, exploration and development activities are capitalized as part of our full cost pool. These capitalized costs include salaries, employee benefits, costs of consulting services and other costs directly associated with those activities. We capitalized general and administrative costs related to our acquisition, exploration and development activities, during the periods ended December 31, 2005, 2004 and 2003 of $1,777,566, $1,885,556 and $1,910,499, respectively.

Capitalized Interest Costs The Company capitalizes interest based on the cost of major development projects which are excluded from current depreciation, depletion and amortization calculations. For the years ended December 31, 2005, 2004 and 2003, the Company capitalized $714,070, $124,419 and $97,227 of interest, respectively. See Unevaluated Properties above for additional information on the criteria for including costs in unevaluated properties.

Stock Compensation 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 market value of the Company s stock at grant date, and therefore, no compensation costs have been recognized under stock option plans. The Company used the income method on a semi-annual basis to estimate the market value of the Company s stock at grant date. As allowed by SFAS No. 123, Accounting for Stock-Based Compensation issued in 1995, GeoMet has 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

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The effects of applying SFAS 123 in this pro forma disclosure may not be representative of future amounts. See Note 9 for additional detail on stock options. The fair value of each option grant was based on the minimum value method with the following 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 3 years for 2005 and 2004, and 4 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 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. We believe that our methodology and valuations represented the estimated fair market value of our common stock at that time.

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	

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. None of our current price risk management activities are designated as accounting hedges, and accordingly, we account 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 and losses which are included in operating expense 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.

Foreign Currency Translation For subsidiaries whose functional currency is deemed to be other than the United States dollar, asset and liability accounts are translated at period end exchange rates and revenue and expenses are translated at average exchange rates prevailing during the period. Translation adjustments are included in the Accumulated Other Comprehensive Income (Loss). Any gains or losses on transactions or monetary assets or liabilities in currencies other than the functional currency are included in net income in the current period. The Company s only foreign subsidiary is its Canadian subsidiary, Hudson s Hope Gas, Ltd.

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

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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. The Company adopted SFAS No. 153 effective July 1, 2005. The adoption of SFAS No. 153 had no effect on the Company s financial statements.

In March 2005, the FASB issued FASB Interpretation (FIN) No. 47 (FIN 47), *Accounting for Conditional Asset Retirement Obligations*. This Interpretation 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 the control of the Company. FIN 47 states that a Company 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 of these liabilities. FIN 47 is effective for fiscal years ending after December 15, 2005. The release of this interpretation did not affect the method we were applying to accrue asset retirement obligations, therefore, the adoption of this interpretation 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,

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requires the Company 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 the Company s share price, the Company is required to estimate a value calculated by substituting the historical volatility of an appropriate industry sector index for the expected volatility of the Company s 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 the Company 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. Pro forma disclosure is no longer an alternative. 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.

Note 3 Note Receivable

The Company has an unsecured note receivable of $323,879 and $348,145 as of December 31, 2005 and 2004, respectively, from a third party included in other noncurrent assets. The note requires payment on a semi-monthly basis, including interest at 8.25%, of $2,168. The fair value of the receivable at December 31, 2005 was approximately $392,860. Scheduled maturities of the note receivable is detailed in the table below.

	Amount
2006	$ 24,266
2007	24,943
2008	27,200
2009	29,662
2010	32,346
Thereafter	209,728
Total note receivable	348,145
Less current portion of note receivable	24,266
Noncurrent note receivable	$ 323,879

Note 4 Asset Retirement Liability

In connection with adoption of SFAS No. 143, on January 1, 2003, the Company recognized asset retirement costs of $397,260 and asset retirement liability of $426,160, of which $21,699 were classified as current. The net difference, net of income taxes, between the Company s previously depleted abandonment costs and the amounts estimated under SFAS 143, was a loss of $19,075, which was recognized during 2003 as a cumulative effect of a change in accounting principle. The cumulative-effect adjustment of $19,075 included

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$32,067 of depletion benefits, $9,825 for deferred tax benefits and $60,967 for accretion of the fair value of the asset retirement obligations.

The following table describes the changes to the Company s asset retirement liability for the years ending December 31, 2005 and 2004.

	2005	2004
Asset retirement obligation at beginning of year	$ 1,169,327	$ 680,636
Liabilities incurred	608,247	647,238
Liabilities settled	(260,040)	(288,929)
Accretion expense	113,094	66,856
Revisions in estimates	259,545	63,526
Asset retirement obligation at end of year	1,890,173	$ 1,169,327
Less: current portion of obligation	51,510	280,569
Long-term asset retirement obligation	1,838,663	888,758

In addition, the Company was required to contribute $80,000 in cash to an escrow account which was to be used to pay for a portion of the abandonment and retirement costs of a gas prospect. The balance in the escrow account was included in *Restricted Cash* on the balance sheet. The balance in the escrow account at December 31, 2004 was $80,243. The retirement obligation at December 31, 2004 for the prospect that the escrow partially funds was $167,699. The gas property which the escrow account was related to was sold in August 2005 and the escrow account was released in full to the Company.

Note 5 Price Risk Management Activities

The Company engages in price risk management activities from time to time. These activities are intended to manage the Company s exposure to fluctuations in the price of natural gas. The Company utilizes derivative financial instruments, primarily using 3-way collars and swaps as the means to manage this price risk. Under collar arrangements, if the index price rises above the ceiling price, the Company pays the counterparty. If the index price falls below the floor price, the counterparty pays the Company.

The Company has elected not to designate any of its current derivative contracts as accounting hedges and accordingly, accounted for its derivative contracts using mark-to-market accounting. During the year ending December 31, 2005, the Company recognized losses on derivative contracts of $19,532,212, which included realized losses of $7,473,004. During the year ending December 31, 2004, the Company recognized losses on derivative contracts of $272,864, which included realized losses of $686,840 and $128,100 amortization of premium payments. During the year ending December 31, 2003, the Company recognized losses on derivative contracts of $145,651, which included realized gains of $9,540 and $53,700 of premium payments.

As of December 31, 2005, the following natural gas derivative contracts were outstanding with prices expressed in dollars per million British thermal units ($/MMBtu) and notional volumes in million British thermal units.

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 October 31, 2007	1,756,000	$ 6.60 7.98	$ 10.28

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At December 31, 2005 and 2004, the fair values of open derivative contracts were a liability of approximately $11.5 million and an asset of $440,585, respectively.

Note 6 Long-Term Debt

The following is a summary of the Company s long-term debt at December 31, 2005, 2004 and 2003:

	2005	2004	2003
Borrowings under bank credit facility	$ 99,000,000	$ 50,500,000	$ 9,000,000
Note payable to a third party, annual installments of $53,000 through January 2011, interest-bearing at 8.25% annually, unsecured	243,166	273,594	301,703
Note payable to an individual, semi-monthly installments of $644, through September 2015, interest-bearing at 12.6% annually, unsecured	146,571	153,779	160,137
Salary continuation payable to an individual, semi-monthly installments of $3,958, through December 2015, noninterest-bearing (less amortization discount of $572,074, with an effective rate of 8.25%), unsecured	623,113	664,838	703,359
Capital lease, monthly payments through February 2005		9,980	68,928
Total debt	100,012,850	51,602,191	10,234,127
Less current maturities included in current liabilities	(86,472)	(89,392)	(132,018)
Total long-term debt	$ 99,926,378	$ 51,512,799	$ 10,102,109

The Company initially entered into a bank credit facility in December 2001. Pursuant to the credit agreement, GeoMet, Inc. (the Borrower) has a $150 million revolving credit facility that permits the Borrower to borrow amounts from time to time based on the available borrowing base as determined in the bank credit facility. The bank credit facility is secured by substantially all of the Company s gas properties. The borrowing base under the bank credit facility is based upon the valuation as of June 30 and December 31 of each year of the Company s gas properties and other factors deemed relevant by the lenders, including Bank of America as agent. The lenders may also request one additional borrowing base re-determination in any fiscal year.

As of December 31, 2005, the borrowing base under the bank credit facility was $120 million and we had $99 million of borrowings outstanding. As of December 31, 2005 outstanding balances on the revolving credit facility bear interest at either the bank s Adjusted Base Rate, which is the bank s base rate but never less than the Federal Funds Rate plus 0.5%, or the Adjusted LIBOR rate plus a margin of 1.25% to 2.25% based on borrowing base usage. Average annual rates for December 31, 2005, 2004, and 2003 were 6.59%, 3.89% and 2.38%, respectively.

The Company is subject to certain restrictive financial and non-financial covenants under the bank credit facility, including a minimum current ratio of 1.0 to 1.0, and a maximum rate of EBITDA to interest expense of 2.75 to 1.0, both as defined in the credit facility agreement. As of December 31, 2005, the Company was in compliance with all of the covenants in the bank credit facility. The bank credit facility matures on November 21, 2007.

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The following were maturities of long-term debt for each of the next five years at December 31, 2005:

Year	Amount
2006	$ 86,475
2007	99,094,230
2008	102,648
2009	111,768
2010	121,792
Thereafter	495,937
Total Debt	$ 100,012,850

Subsequent to December 31, 2005, the bank credit facility was amended to reduce the Adjusted LIBOR margin to 1.0% to 2.0%. The amendment also extended the maturity date from November 21, 2007 to January 6, 2011. See note 15 Subsequent Events regarding repayment of borrowings under our bank facility in January 2006.

The total fair value of the two notes payable and the salary continuation payable as of December 31, 2005 was approximately $1.2 million.

Note 7 Income Taxes

An analysis of the Company s deferred taxes follows:

	2005	2004
Deferred tax assets:		
Current:		
Tax basis in excess of book basis of derivative contracts	$ 2,911,808	$
Long-term:		
Net operating loss carryforward	21,421,024	12,953,628
Compensation expense and other	372,213	353,492
Tax basis in excess of book basis of derivative contracts	1,072,117	513,085
Accrued asset retirement obligations	598,819	385,717

Alternative minimum tax credit carryforward	115,907	132,135
Total deferred tax assets	23,580,080	14,338,057
Deferred tax liability book basis of gas properties in excess of tax basis	(54,234,625)	(26,749,942)
Net deferred tax liability	$ (30,654,545)	$ (12,411,885)

For tax reporting purposes, the Company had net operating loss carryforwards of approximately $62 million at December 31, 2005 that are available to reduce future U.S. taxable income. If not utilized, such carryforwards would begin to expire in 2022. There was no net income or net loss for the Company s Canadian subsidiary for the years ended December 31, 2005 and 2004.

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Federal income tax expense (benefit) for each of the years ended December 31, 2005, 2004, and 2003 was different than the amount computed using the Federal statutory rate for the following reasons:

	2005	%	2004	%	2003	%
Amount computed using statutory rates	$ (1,022,988)	(34.0)%	$ 2,287,497	34.0%	$ 1,625,928	34.0%
State income taxes net of federal benefit	16,500	0.6%	16,500	0.2%	16,500	0.3%
Nondeductible items and other	13,314	0.4%	8,011	0.1%	8,500	0.2%
Income tax provision (benefit)	$ (993,174)	(33.0)%	$ 2,312,008	34.3%	$ 1,650,928	34.5%

The following components of the federal income tax expense (benefit) for the years ended December 31, 2005, 2004 and 2003 are as follows:

	Years Ended December 31,		
	2005	2004	2003
Current	$ 8,772	$ 65,000	$ 25,000
Deferred	(1,001,946)	2,247,008	1,625,928
Income tax provision (benefit)	$ (993,174)	$ 2,312,008	$ 1,650,928

Note 8 Common Stock

At December 31, 2005, the Company had 40,000,000 shares of common stock authorized, adjusted for a four-for-one stock split on January 24, 2006. See additional information regarding changes in Common Stock in Note 15 Subsequent Events.

During 2005, GeoMet issued 4,438,768 shares of its common stock valued at $7.64 per share for the minority interest in its majority-owned subsidiary s common stock. In connection with this acquisition GeoMet issued to each minority interest owner and holder of incentive stock options of the majority-owned subsidiary an option to purchase common stock of GeoMet at the per share exchange value of $7.64 (the non-dilution option). Within 30 days of issuance, the holder of the non-dilution option could exercise the option to purchase, with cash and/or loan from GeoMet, up to the amount of GeoMet s common stock necessary to prevent any dilution that resulted from the merger. The 2005 notes issued to purchase any stock are secured by the stock, with full recourse, earn interest at an annual rate of 6% and mature on the earlier of

April 14, 2009, sixty days after the holder ceases to be an employee or the occurrence of a Triggering Transaction as defined in the non-dilution option agreement. Non-dilution options were exercised to purchase 1,456,668 shares of GeoMet common stock. The purchases were financed with $10,905,144 in notes and $227,380 in cash. The notes receivable, including accrued interest, is shown as a reduction of stockholders equity, and approximately $10,500,000 of these notes were repaid in full in January 2006. See Note 15 Subsequent Events for additional information on notes receivable payments.

During 2004, the Company issued 4,000,000 common shares at $2.50 per share, to the existing stockholders in proportion to their original ownership, for cash of $9,100,000 and a note receivable of $900,000. During 2003, the Company increased the authorized common shares by 8,000,000 and issued 4,000,000 and 8,000,000 common shares in May and September, respectively, at $2.50 per share, to the existing stockholders in proportion to their original ownership, for cash of $27,300,000 and a note receivable of $2,700,000. The 2004 and 2003 notes issued to purchase stock, including accrued interest, are shown as a reduction of stockholders equity. The terms of these notes are full recourse, earn interest at an annual rate of 5.87% and become due and payable on the earlier of April 14, 2009, six months after the holder ceases to be an employee or the occurrence of a Triggering

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GEOMET, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

Transaction as defined in the note agreement. All of these notes were repaid in full with interest in January 2006. See Note 15 Subsequent Events for additional information on notes receivable payment.

All Common Stock issued was subject to a Stockholders Agreement which, among other things restricted the transfer and disposition of the stock. The Stockholders Agreement also specified that all issuances of common stock must be issued at a price of $2.50 per share up to a maximum funding of $60 million. All provisions of the Stockholders Agreement, except for the provisions related to non-qualified stock option vesting, was terminated as of April 2005.

Note 9 Stock Options

Qualified Stock Options

The Company currently has one qualified stock option plan the 2005 Plan that authorizes the granting of incentive stock options to key employees. The exercise price of each option may not be less than 100% of the fair market value of a share of Common Stock on the date of grant. The options have a term of seven years, vest evenly over four years and become exercisable on each of the first four anniversary dates of issuance. Prior to the effective date of the merger, the option entitled the holder to acquire shares of the Company s majority-owned subsidiary. Effective with the merger of the majority-owned subsidiary into GeoMet, all of the outstanding options under this plan became fully vested and the options were exchanged for options to acquire common stock of GeoMet. The option tables for the years ended 2004 and 2003 have been converted into equivalent options of GeoMet.

A summary of changes in the incentive stock options outstanding as of December 31, 2005, 2004 and 2003 is presented below:

	Years Ended December 31,					
	2005		2004		2003	
	Number of Options	Weighted Average Price	Number of Options	Weighted Average Price	Shares	Weighted Average Price
Outstanding at beginning of year	873,368	$ 1.50	871,500	$ 1.31	759,640	$ 1.23
Granted	153,244	7.36	55,928	4.08	111,860	1.80

Forfeited	(54,060)	1.07	(54,060)	1.07		
Exercised	(79,228)	1.25				
Outstanding at end of year	893,324	$ 2.55	873,368	$ 1.50	871,500	$ 1.31
Options exercisable	805,324	$ 1.99	512,600	$ 1.31	322,472	$ 1.17
Weighted average fair value of options granted	$ 0.71		$ 0.14		$ 0.28	

The Company determines the fair value of options issued using the minimum value method.

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GEOMET, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

The following table summarizes information regarding incentive stock options outstanding at December 31, 2005:

	Outstanding Options			Exercisable Options	
Range of Exercise Price	**Shares Underlying Options**	**Weighted Average Remaining Contractual Life**	**Weighted Average Exercise Price**	**Shares Underlying Options**	**Weighted Average Exercise Price**
$0.00 - $1.07	363,504	2.2 years	$ 1.07	363,504	$ 1.07
$1.50 - $1.82	320,648	3.8 years	$ 1.59	320,648	$ 1.59
$1.83 - $4.08	55,928	5.0 years	$ 4.08	55,928	$ 4.08
$4.09 - $7.64	153,244	6.3 years	$ 7.36	65,244	$ 6.98
	893,324	3.6 years	$ 2.55	805,324	$ 1.99

Non-Qualified Stock Options

In conjunction with the sale of common stock to certain executive officers of the Company during 2000, the Company granted these officers options to acquire 400,000 shares of common stock of GeoMet at $2.50 per share. The holders of the options also had a right to be issued additional options to acquire five percent of any additional common stock issued at a price of $2.50 per share. The executive officers were issued options to acquire 600,000 shares in conjunction with the issuance of 12,000,000 common shares in 2003 and were issued options to acquire 200,000 shares in conjunction with the issuance of 4,000,000 common shares in 2004. The options have a term of 10 years and vest ratably over three years and become exercisable on each of the first three anniversary dates of the agreement. The weighted average fair value of options granted during the years ended 2004 and 2003 were $0.20 and $0.24. As of December 31, 2005, 2004, and 2003, the outstanding options and weighted average remaining contractual life was 1,200,000, 1,200,000, and 1,000,000 shares and 7.1, 7.8 and 8.5 years, respectively. The Company determined the fair value of options issued using the minimum value method based on the expected life of the option. For the year ended December 31, 2005 no non-qualified stock options were exercised, forfeited, or granted. All options granted since inception are still outstanding at December 31, 2005. Non-qualified stock options exercisable for the years ending December 31, 2005, 2004 and 2003, were 866,680, 600,008, and 400,000.

Note 10 Profit Sharing Plan

Substantially all of the employees are covered by the Company s profit sharing plan under Section 401(k) of the Internal Revenue Code. Eligible employees may make contributions to the plan by electing to defer some of their compensation. The Company is required to match 50 percent of total contributions up to a total of six percent of their annual compensation. The Company s matching contribution vests evenly over three years.

The Company s contribution to the Plan for the years ended December 31, 2005, 2004 and 2003 was $122,286, $108,836 and $101,375, respectively.

Note 11 Research and Development Agreement

During 2002, the Company entered into a one year joint development agreement (the Agreement) with a third party to design, test and build prototype jet drilling working tools, rigs, and systems in accordance with patented inventions and technology owned by a third party, and to provide the Company an option to license the patented inventions and technology for commercial development in enhancing coalbed methane development and production. Pursuant to the Agreement (as amended), the Company agreed to pay up to $565,000 in costs, excluding internal costs, associated with the joint development project which were expensed as research and development costs.

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GEOMET, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

During the term of the Agreement, the Company had an option to acquire an exclusive license to use the existing patent rights and any patent rights that arose as a result of the Agreement in the development of coalbed methane for a five year period beginning with the execution of the license agreement. Upon execution of the license agreement, the Company agreed to pay a minimum annual royalty to a third party of $50,000 and an overriding royalty interest of one percent of natural gas produced from each well utilizing the technology developed under the Agreement. The license agreement could be automatically extended for successive one year periods by paying the minimum royalty.

During 2004, the Company acquired a nonexclusive license to use the patented inventions and technology for enhancing coalbed methane development and production for an initial fee of $50,000. Depending on the use of the technology, additional license fees will be due in the form of per well completion fees and overriding royalties. The initial license term ends on July 8, 2006 and can be extended for indefinite annual periods for $10,000 per year. However, the Company is continuing to expend funds to convert the research to a commercially viable technology. All amounts expended for this research have been expensed as research and development costs.

Note 12 Commitments and Contingencies

Litigation From time to time the Company is a party to litigation in the normal course of business. While the outcome of lawsuits or other proceedings against the Company cannot be predicted with certainty, management does not believe that the adverse effect on its financial condition, results of operations or cash flows of the Company, if any, will be material.

We filed a claim in the 116th District Court of Dallas County, Texas on June 9, 2004 against El Paso Production Company, CMV Joint Venture and CDX Minerals, LLC seeking a declaratory judgment of our rights under a joint operating agreement covering certain properties in White Oak Creek. We had previously entered into an agreement to sell our interest to CDX, subject to a preferential right to purchase held by El Paso, which El Paso subsequently exercised. A dispute arose as to whether the preferential right granted under the agreement applied to overriding royalty interests and other related interests. We have asserted that the preferential right to purchase does not include overriding royalty interests and that we are entitled to retain all overriding royalty interests we possess under the agreement. The trial court rendered judgment in our favor, and El Paso has appealed the decision of the trial court. While we believe that we are entitled to retain these interests, a judgment against us would result in our being required to sell the overriding royalty interest to El Paso for a price of approximately $10.5 million; however, this amount would be reduced by any proceeds we have received from production since the effective date of the sale.

As of December 31, 2005, there were no known environmental or other regulatory matters related to the Company s operations which are reasonably expected to result in a material liability to the Company.

Operating Lease Commitments The Company has operating leases for office space, office equipment and field compressors expiring in various years through 2012. Future minimum lease commitments as of December 31, 2005 under noncancelable operating leases having remaining terms in excess of one year are as follows:

Year Ended December 31,	Amount
2006	$ 1,185,309
2007	1,166,953
2008	1,128,758
2009	763,372
2010	639,429
Thereafter	853,007
Total future minimum lease commitments	$ 5,736,828

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GEOMET, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

Total rental expenses under operating leases were approximately $1,048,083, $669,579 and $350,699 for the years ended December 31, 2005, 2004 and 2003, respectively.

Major Customers For the years ended December 31, 2005 and 2004, one customer purchased approximately 99% of the Company s natural gas production. For the year ended December 31, 2003, one customer purchased approximately 46% and another customer purchased approximately 54% of the Company s natural gas production. Due to the availability of other purchasers, the Company does not believe that the loss of its current purchasers would adversely affect the Company s results of operations.

Transportation Contracts In 2004 and 2005, the Company entered into firm transportation contracts with a pipeline. As of December 31, 2005 under the contracts the Company can transport maximum daily volumes of 17,000 dekatherms continuing until October 31, 2006. Beginning November 1, 2006, unless the annual contract is extended, the maximum decreases to 7,000 continuing until October 31, 2010. As of December 31, 2005, the maximum commitment remaining under the transportation contract is approximately $3,023,856.

Note 13 Acquisition and Disposition

On April 30, 2004, the Company acquired additional working interests in properties that it operates in West Virginia for approximately $27 million in cash. The entire purchase price was allocated to Proved Properties. The purchase price is subject to a contingent payable of up to an additional $3 million dependent on natural gas prices and production on the properties acquired. When the contingency is resolved on December 31, 2007 any amount paid will be added to Proved Properties in accordance with SFAS No. 141 Business Combinations. The acquisition was funded by borrowings under the bank credit facility.

On June 7, 2004, the Company sold all of its working interest in a non-operated field in Alabama for approximately $21 million in cash.

Note 14 Related Party Transactions

On July 21, 2003, GeoMet loaned its Chief Financial Officer $250,000 to provide liquidity in connection with a divorce settlement so that the executive could retain ownership of his common stock. The full recourse loan accrues interest at an annual rate of 5.87% and becomes due and payable on the earlier of April 14, 2009, six months after the holder ceases to be an employee or the occurrence of a Triggering Transaction as defined in the note agreement. The note and accrued interest was paid in full on January 2006 (See Note 15 Subsequent Events) and at December 31, 2005 is shown as Accounts receivable in the current asset section of the balance sheet.

Note 15 Subsequent Events

Effective January 24, 2006, GeoMet s Board of Directors approved an increase in the authorized capital stock of the Company from 10,000,000 shares of common stock at December 31, 2005 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.

On January 30, 2006, we completed a private placement of 10,000,000 shares of our common stock, consisting of 2,067,023 shares issued by us and 7,932,977 shares sold by certain of our existing stockholders, to qualified institutional buyers in a transaction exempt from registration under the Securities Act. We received aggregate consideration of approximately $25.0 million or $12.09 per share. We did not receive any proceeds from the shares sold by certain of our existing stockholders. In addition, we received approximately $17.5

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GEOMET, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

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 bank credit facility and for general corporate purposes. In connection with this private placement on February 7, 2006, we sold an additional 250,000 shares of our common stock to qualified institutional buyers from which we received aggregate consideration of approximately $3.0 million, or $12.09 per share, pursuant to the initial purchaser s option to purchase additional shares. The net proceeds generated from this sale were used to repay a portion of the borrowings under our bank credit facility and for general corporate purposes.

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SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION ON GAS

EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES (UNAUDITED)

This supplemental schedule provides unaudited information pursuant to Statement of Financial Accounting Standards No. 69, *Disclosures About Oil and Natural Gas Producing Activities*, (SFAS 69) and certain other information.

Capitalized Costs Capitalized costs and accumulated depreciation, depletion and amortization relating to the Company s gas producing activities, all of which are conducted within the continental United States and Canada, at December 31, 2005, 2004 and 2003 are summarized below.

The Company capitalizes certain payroll and other internal costs attributable to acquisition, exploration and development activities as part of its investment in natural gas properties over the periods benefited by these activities. During the years ended December 31, 2005, 2004 and 2003, these capitalized costs amounted to $1,777,566, $1,885,556 and $1,910,499, respectively. Capitalized costs do not include any costs related to production, general corporate overhead or similar activities. For the years ended December 31, 2005, 2004 and 2003, interest costs of $714,070, $124,419 and $97,227, respectively, were capitalized. The capitalized costs below do not include $48,229,135 and $1,996,719 recorded in Proved Properties as a result of the acquisition of common stock of the majority-owned subsidiary in April 2005, and November 2004, respectively.

	For the Years Ended December 31,		
	2005	2004	2003
Unevaluated properties United States	$ 14,789,928	$ 10,370,170	$ 9,026,356
Unevaluated properties Canada	5,890,784	709,088	
Properties subject to amortization United States	179,293,368	129,194,262	66,576,545
Capitalized costs consolidated	199,974,080	140,273,520	75,602,901
Accumulated depreciation, depletion and amortization United States	(14,455,583)	(9,762,900)	(7,276,664)
Net capitalized costs consolidated	$ 185,518,497	$ 130,510,620	$ 68,326,237
Net capitalized costs Canada	$ 5,890,784	$ 709,088	$
Net capitalized costs United States	179,627,713	129,801,532	68,326,237
Net capitalized costs consolidated	$ 185,518,497	$ 130,510,620	$ 68,326,237

Capitalized Costs Incurred

The following tables discloses costs incurred in gas property acquisition, exploration and development activities for the years ended December 31, 2005, 2004 and 2003.

	For the Years Ended December 31,		
	2005	2004	2003
Acquisition costs:			
Proved	$ 540,767	$ 27,805,246	$
Unproved	1,242,621	942,623	1,582,217
Exploration costs	5,621,775	7,120,683	19,422,697
Development costs	47,414,118	49,789,779	15,117,696
Total costs incurred United States	54,819,281	85,658,331	36,122,610
Exploration costs incurred Canada	4,876,703	709,088	
Total costs incurred Canada	4,876,703	709,088	
Total costs incurred consolidated	$ 59,695,984	$ 86,367,219	$ 36,122,610

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Additions to Unevaluated Properties

The following table provides a summary of unevaluated costs not being amortized as of December 31, 2005, by the year in which the costs were incurred.

At December 31, 2005 our projects in North Central Louisiana and British Columbia accounted for approximately $12.1 million and $5.7 million, respectively, of the total balance of unevaluated properties. We estimate the costs to be evaluated within three years.

	Costs incurred as of December 31,				
United States	**Total**	**2005**	**2004**	**2003**	**2002 & Prior**
Property acquisition	$ 3,421,193	$ 1,352,932	$ 874,647	$ 681,196	$ 512,418
Exploration	10,936,940	3,600,437	4,862,025	2,332,359	142,119
Capitalized interest	431,795	290,320	141,475		
Total	14,789,928	5,243,689	5,878,147	3,013,555	654,537
Canada					
Property acquisition	203,724	118,560	85,164		
Exploration	5,587,745	4,940,165	647,580		
Capitalized interest	99,315	99,315			
Total	5,890,784	5,158,040	732,744		
Total unevaluated consolidated	$ 20,680,712	$ 10,401,729	$ 6,610,891	3,013,555	654,537

Reserves The following table summarizes the Company s net ownership interests in estimated quantities of proved gas reserves and changes in net proved reserves, all of which are located in the continental United States. Reserve estimates for natural gas contained below were prepared by DeGolyer and MacNaughton, independent petroleum engineers.

Users of this information should be aware that the process of estimating quantities of proved, proved developed and proved undeveloped natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history, and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions (upward or downward) to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

	2005	**2004**	**2003**

Natural Gas Reserves (Mcf)			
Proved reserves at beginning of year	209,851,000	103,929,000	35,461,000
Revisions of previous estimates	(5,152,000)	(5,831,000)	(3,020,000)
Extensions and discoveries	62,406,000	91,535,000	73,972,000
Acquisition		31,775,000	
Disposition		(8,370,000)	
Production	(4,594,000)	(3,187,000)	(2,484,000)
Proved reserves at end of year	262,511,000	209,851,000	103,929,000
Proved developed reserves at beginning of year	160,935,000	80,780,000	29,432,000
Proved developed reserves at end of year	195,139,000	160,935,000	80,780,000

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The following table presents the standardized measure of future net cash flows related to proved gas reserves in accordance with SFAS No. 69. All components of the standardized measure are from proved reserves, all of which are located entirely within the continental United States. As prescribed by this statement, the amounts shown are based on prices and costs at December 31, 2005, 2004 and 2003, and assume continuation of existing economic conditions. Future income taxes are based on year-end statutory rates, adjusted for tax credits. A discount factor of 10 percent was used to reflect the timing of future net cash flows. Extensive judgments are involved in estimating the timing of future production and the costs that will be incurred throughout the remaining lives of the fields. Accordingly, the estimates of future net revenues from proved reserves and the present value thereof may not be materially correct when judged against actual subsequent results. Further, since prices and costs do not remain static, and no price or cost changes have been considered, and future production and development costs are estimated to be incurred in developing and producing the estimated proved gas reserves, the results are not necessarily indicative of the fair market value of estimated proved reserves, and the results may not be comparable to estimates disclosed by other gas producers.

Standardized Measure	**2005**	**2004**	**2003**
Future cash inflows	$ 2,536,279,000	$ 1,302,830,000	$ 599,501,000
Future production costs	(463,416,000)	(290,425,000)	(125,765,000)
Future development costs	(76,297,000)	(38,242,000)	(23,832,000)
Future income taxes	(579,689,000)	(274,975,000)	(125,858,000)
Future net cash flows	1,416,877,000	699,188,000	324,046,000
10% annual discount to reflect timing of cash flows	(784,212,000)	(349,433,000)	(151,498,000)
Standardized measure of discounted future net cash flows	$ 632,665,000	$ 349,755,000	$ 172,548,000

Changes in standardized measure relating to proved gas reserves for the years ended December 31, 2005, 2004 and 2003 are summarized below:

Changes in Standardized Measure	**2005**	**2004**	**2003**
Standardized measure at beginning of year	$ 349,755,000	$ 172,548,000	$ 45,427,000
Sales and transfers of oil and gas produced net of production cost	(28,952,000)	(12,014,000)	(8,654,000)
Net changes in prices and production cost	276,690,000	8,472,000	21,983,000
Extensions and discoveries	197,336,000	217,211,000	176,731,000
Acquisition/disposition (net)		59,308,000	
Net change in development cost	(31,196,000)	(11,772,000)	(17,822,000)
Revision of previous quantity estimates	(17,705,000)	(13,882,000)	(7,270,000)
Accretion of discount before income taxes	48,182,000	23,689,000	6,444,000
Net change in income taxes	(115,420,000)	(67,732,000)	(45,320,000)
Changes in production rates (timing) and other	(46,025,000)	(26,073,000)	1,029,000
Subtotal net change	282,910,000	177,207,000	127,121,000
Standardized measure at end of year	$ 632,665,000	$ 349,755,000	$ 172,548,000

The weighted average prices of gas used with the above tables at December 31, 2005, 2004 and 2003 were $9.66, $6.21 and $5.77 per Mcf, respectively. The Company s cash flow amounts do not include a reduction for estimated future plugging and abandonment costs that has been reflected as a liability on the balance sheet at December 31, 2005, 2004, and 2003 in accordance with SFAS No. 143 because the net change was not material for the periods presented.

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GEOMET, INC. AND SUBSIDIARIES

Consolidated Balance Sheet

	March 31, 2006 (Unaudited)
ASSETS	
Current Assets:	
Cash and cash equivalents	$ 1,340,471
Accounts receivable	3,958,410
Current portion of notes receivable	24,324
Deferred tax asset	
Other current assets	370,883
Total current assets	5,694,088
Gas Properties utilizing the full cost method of accounting:	
Proved gas properties	245,498,601
Unevaluated gas properties, not subject to amortization	23,740,015
Other property and equipment	2,089,995
Total property and equipment	271,328,611
Less accumulated depreciation, depletion, and amortization	(16,954,465)
Property and equipment net	254,374,146
Other noncurrent assets:	
Note receivable	317,844
Other	565,168
Total other noncurrent assets	883,012
TOTAL ASSETS	$ 260,951,246
LIABILITIES AND STOCKHOLDERS EQUITY	
Current Liabilities:	
Accounts payable	$ 10,545,468
Deferred tax liability	757,505
Derivative liability	1,893,762
Asset retirement liability	51,473
Accrued liabilities	739,743
Current portion of long-term debt	90,394
Total current liabilities	14,078,345
Long-term debt	58,376,577
Long-term derivative liability	576,224

Asset retirement liability	1,912,047
Other long-term accrued liabilities	258,573
Deferred income taxes	38,535,973
Total liabilities	113,737,739
Commitments and Contingencies (Note 10)	
Stockholders Equity:	
Preferred stock, $0.001 par value authorized 10,000, none issued	
Common stock, $0.001 par value authorized 40,000,000, and 24,000,000 shares; issued and outstanding 32,614,021 and 29,974,664 at March 31, 2006 and December 31, 2005, respectively	32,614
Paid-in capital	133,955,252
Accumulated other comprehensive income	31,260
Retained earnings	13,607,026
Less notes receivable	(412,645)
Total stockholders equity	147,213,507
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 260,951,246

See accompanying Notes to Consolidated Financial Statements.

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GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Operations and Comprehensive Income

	Three Months Ended March 31,	
	2006	2005
	(Unaudited)	
Revenues:		
Gas sales	$ 12,311,409	$ 6,368,796
Operating fees and other		137,957
Total revenues	12,311,409	6,506,753
Expenses:		
Lease operating expense	2,840,864	2,083,469
Compression and transportation expense	1,076,490	721,009
Production taxes	268,744	125,630
Depreciation, depletion and amortization	1,834,005	884,509
Research and development	69,255	995
General and administrative	1,019,556	751,235
Realized losses (gains) on derivative contracts	595,572	(165,445)
Unrealized losses (gains) from the change in market value of open derivative contracts	(9,073,532)	4,839,427
Total operating expenses	(1,369,046)	9,240,829
Income (loss) from operations	13,680,455	(2,734,076)
Other income (expense):		
Interest income	10,894	17,504
Interest expense (net of amounts capitalized)	(863,374)	(609,133)
Other expenses	(13,377)	
Total other income (expense)	(865,857)	(591,629)
Income (loss) before income taxes and minority interest, net of income tax	12,814,598	(3,325,705)
Income tax expense (benefit)	5,651,500	(1,105,741)
Income (loss) before minority interest, net of income tax	7,163,098	(2,219,964)
Minority interest		(506,759)
Net income (loss)	$ 7,163,098	$ (1,713,205)
Other comprehensive income, net of income taxes		
Foreign currency translation adjustment, net of income tax of $0	25,050	(3,992)
Comprehensive Income (loss)	$ 7,138,048	$ (1,717,197)
Earnings per common share:		
Basic		

Net income (loss) per share basic	$ 0.23	$ (0.07)
Diluted		
Net income (loss) per share diluted	$ 0.22	$ (0.07)
Weighted average number of common shares:		
Basic	31,707,241	24,000,000
Diluted	32,901,915	24,000,000

See accompanying Notes to Consolidated Financial Statements.

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GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Stockholders Equity and Accumulated Other Comprehensive Income

	March 31, 2006 (Unaudited)
Preferred stock, $0.001 par value shares outstanding, none	
Common stock, $0.001 par value shares outstanding:	
Balance at beginning of year	29,974,664
144A Offering, Sale of common stock	2,317,023
Exercise of stock options	322,334
Balance at end of period	32,614,021
Common stock, $0.001 par value:	
Balance at beginning of period	$ 29,975
144A Offering, Sale of common stock	2,317
Exercise of stock options	322
Balance at end of period	$ 32,614
Paid-in capital:	
Balance at beginning of period	$ 106,408,915
144A Offering, Sale of common stock	28,010,491
Exercise of stock options	1,583,226
Offering costs	(1,539,791)
Accrued interest on all notes receivable issued to purchase common stock, net of income tax	(507,589)
Balance at end of period	$ 133,955,252
Accumulated other comprehensive income:	
Balance at beginning of period	$ 56,310
Foreign currency translation adjustment, net of income tax of $0	(25,050)
Balance at end of period	$ 31,260
Retained earnings:	
Balance at beginning of period	$ 6,443,928
Net income	7,163,098
Balance at end of period	$ 13,607,026
Notes receivable:	
Balance at beginning of period	$ (17,516,852)
Payments	17,184,357

Accrued interest on all notes receivable issued to purchase common stock	(80,150)
Balance at end of period	$ (412,645)
Total Stockholders Equity	$ 147,213,507

See accompanying Notes to Consolidated Financial Statements.

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GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Cash Flows

	Three Months Ended March 31,	
	2006	2005
	(Unaudited)	
Cash flows provided by operating activities:		
Net income (loss)	$ 7,163,098	$ (1,713,205)
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:		
Depreciation, depletion and amortization	1,871,859	909,124
Amortization of debt issuance costs	35,852	38,645
Minority interest		(506,757)
Deferred income taxes	5,596,497	(1,315,846)
Unrealized losses (gains) from the change in market value of open derivative contracts (including premium amortization)	(9,073,532)	4,839,427
Stock-based compensation	102,962	
Loss on sale of assets	12,582	
Accretion expense	36,042	21,005
Changes in operating assets and liabilities:		
Accounts receivable	1,617,287	(30,574)
Other current assets	43,349	45,152
Accounts payable	3,623,928	599,455
Other accrued liabilities	(526,246)	(190,639)
Net cash provided by operating activities	10,503,678	2,695,787
Cash flows used in investing activities:		
Capital expenditures	(13,326,775)	(18,130,542)
Proceeds from sale of properties	3,457	
Collection of notes receivable	291,920	
Other assets	(6,253)	(3,683)
Net cash used in investing activities	(13,037,651)	(18,134,225)
Cash flows provided by financing activities:		
Debt issuance costs	(203,977)	
Proceeds from exercise of stock options	646,178	
Equity offering costs	(823,347)	
Proceeds from sales of common stock	28,012,808	
Credit facility borrowings	12,500,000	16,000,000
Proceeds from notes receivable and accrued interest	17,184,357	
Payments on credit facility and other debt	(54,045,879)	(52,200)
Net cash provided by financing activities	3,270,140	15,947,800
Effect of exchange rate changes on cash	(11,502)	(6,918)
Increase in cash and cash equivalents	724,665	502,443
Cash and cash equivalents at beginning of period	615,806	3,013,723

Cash and cash equivalents at end of period	$ 1,340,471	$ 3,516,166

See accompanying Notes to Consolidated Financial Statements.

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GEOMET, INC. AND SUBSIDIARIES

Notes to Consolidated Financial Statements

Note 1 Organization and Our Business

GeoMet, Inc. (GeoMet) (formerly GeoMet Resources, Inc.) was incorporated under the laws of the state of Delaware on November 9, 2000. GeoMet is an independent natural gas producer involved in the exploration, development and production of natural gas from coal seams (coal bed methane). Our principal operations and producing properties are located in Alabama, West Virginia, and Virginia. GeoMet operates in one segment, natural gas exploration, development and production, almost exclusively within the continental United States.

These un-audited consolidated financial statements reflect, in the opinion of the Company s management, all adjustments, consisting only of normal and recurring adjustments, necessary to present fairly the financial position as of, and results of operations for, the interim periods presented. These financial statements have been prepared in accordance with the guidelines of interim reporting; therefore, do not include all disclosures required for year end financial statements prepared in conformity with accounting principles generally accepted in the United State of America. Interim period results are not necessarily indicative of results of operations or cash flows for the full year. Certain prior year amounts have been reclassified to conform to current year presentation.

On April 13, 2005, GeoMet acquired, through a stock exchange, the minority interest in its 81% owned subsidiary and merged the subsidiary into GeoMet. Following the merger, GeoMet changed its name from GeoMet Resources, Inc. to GeoMet, Inc. In connection with this transaction, GeoMet exchanged 4,438,768 shares of its common stock valued at $7.64 per share for all of the common stock of the subsidiary that it did not already own, approximately 19.05%. The acquisition was accounted for as a purchase in accordance with SFAS No. 141, *Business Combinations* whereby the purchase price of the net assets acquired was allocated to those net assets based on their fair value. Goodwill was not recorded because the purchase price less than the fair value of net assets acquired. The exchange value was determined through negotiations between a special committee of the 81% owned subsidiary s board of directors and management.

The following table summarizes the final allocation of fair values to the net assets acquired at the merger date:

	April 13, 2005
Natural gas properties and equipment	$ 53,052,049
Minority interest	2,092,058
Deferred tax liability	(21,220,820)
Net assets acquired	$ 33,923,287

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GEOMET, INC. AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

Note 2 Net Income Per Share

Net Income (Loss) Per Share of Common Stock Basic earnings per share is calculated by dividing net income (loss) by the weighted average number of shares of common stock outstanding during the period. No dilution for any potentially dilutive securities is included. Fully diluted earnings per share assumes the conversion of all potentially dilutive securities and is calculated by dividing net income by the sum of the weighted average number of shares of common stock outstanding plus potentially dilutive securities. Dilutive earnings per share consider the impact of potentially dilutive securities except in periods in which there is a loss because the inclusion of the potential common shares would have an anti-dilutive effect. A reconciliation of the numerator and denominator is as follows:

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
Numerator		
Net income (loss) available to common stockholders basic EPS	$ 7,163,098	$ (1,713,205)
Net income (loss) available to common stockholders diluted EPS	$ 7,163,098	$ (1,713,205)
Denominator		
Weighted average shares outstanding	31,707,241	24,000,000
Add dilutive securities:		
Stock Options	1,194,674	
Total weighted average shares outstanding and dilutive securities	32,901,915	24,000,000

The three months ended March 31, 2005 resulted in a net loss per share of common stock. As a result, the fully diluted earnings per share excluded the potential outstanding option to purchase 1,200,000 common shares and the effect on minority interest from exercise of options to acquire subsidiary common stock for this period because the effect would be anti-dilutive. The minority interest was acquired in April 2005 and therefore has no effect for the three months ended March 31, 2006.

Note 3 Note Receivable

The Company has an unsecured note receivable of $342,168 as of March 31, 2006, respectively, from a third party included in other non-current assets. The note requires payment on a semi-monthly basis, including interest at 8.25%, of approximately $2,000.

Note 4 Gas Properties

The Company uses the full cost method of accounting for its investment in gas properties. Under this method of accounting, all costs of acquisition, exploration and development of gas reserves (including such costs as leasehold acquisition costs, geological expenditures, dry hole costs related to unsuccessful projects, tangible and intangible development costs) included in the full cost pool. In addition, the Company capitalizes interest expense, direct general and administrative expenses, direct stock-based compensation expense, and additions resulting from asset retirement liabilities. To the extent that capitalized costs of gas properties, net of accumulated depreciation, depletion and amortization, exceed the discounted future net revenues of proved gas reserves net of deferred taxes, such excess capitalized costs would be charged to operations. No such charges to operations were required during the three months ended March 31, 2006.

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GEOMET, INC. AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

Note 5 Asset Retirement Obligation

The Company records an asset retirement obligation (ARO) on the consolidated balance sheet and capitalizes the asset retirement costs in gas properties in the period in which the retirement obligation is incurred only if a reasonable estimate of the fair value of an obligation can be made. The amount of the ARO and the costs capitalized are equal to the estimated future costs to satisfy the obligation using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, which is then discounted back to the date the abandonment obligation was incurred using an assumed cost of funds for the Company. Once the obligation is recorded, the ARO is accreted to its future estimated value using the same assumed cost of funds.

The following table describes the changes to the Company s asset retirement liability for the three months ended March 31, 2006:

Asset retirement obligation at beginning of year	$ 1,890,173
Liabilities incurred	65,903
Liabilities settled	(33,681)
Accretion expense	41,363
Revisions in estimates	
Foreign currency translation	(238)
Asset retirement obligation at end of period	1,963,520
Less: current portion of obligation	51,473
Long-term asset retirement obligation	$ 1,912,047

Note 6 Price Risk Management Activities

The Company engages in price risk management activities from time to time. These activities are intended to manage the Company s exposure to fluctuations in the price of natural gas. The Company utilizes derivative financial instruments, primarily 3-way collars and swaps, as the means to manage this price risk. Under collar arrangements, if the index price rises above the ceiling price, the Company pays the counterparty. If the index price falls below the floor price, the counterparty pays the Company.

The Company has elected not to designate any of its current derivative contracts as accounting hedges under FASB 133, Accounting for Derivative Instruments and Hedging Activities, and accordingly, accounted for its derivative contracts using mark-to-market accounting. During the three months ended March 31, 2006, the Company recognized gains on derivative contracts of $8,477,960, which included realized losses of $595,572. During the three months ended March 31, 2005, the Company recognized losses on derivative contracts of $4,673,982, which included realized gains of $165,445.

As of March 31, 2006, the following natural gas derivative contracts were outstanding with prices expressed in dollars per million British thermal units ($/MMBtu) and notional volumes in million British thermal units.

Instrument Type	Production Period	Volumes (MMBtu)	Weighted Average Floor Price ($/MMBtu)	Cap ($/ MMBtu)
Collars (3 way)	April 1 December 31, 2006	3,178,000	$ 6.03 7.23	$ 8.98
Collars (3 way)	January 1 October 31, 2007	1,756,000	$ 6.60 7.98	$ 10.28

At March 31, 2006 and December 31, 2005, the fair values of open derivative contracts were liabilities of approximately $2.5 million and $11.5 million, respectively.

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GEOMET, INC. AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

Note 7 Long-Term Debt

The following is a summary of long-term debt at March 31, 2006:

	March 31, 2006
Borrowings under bank credit facility	$ 57,500,000
Note payable to a third party, annual installments of $53,000 through January 2011, interest-bearing at 8.25% annually, unsecured	210,227
Note payable to an individual, semi-monthly installments of $644, through September 2015, interest-bearing at 12.6% annually, unsecured	144,623
Salary continuation payable to an individual, semi-monthly installments of $3,958, through December 2015, non-interest-bearing (less amortization discount of $572,074, with an effective rate of 8.25%), unsecured	612,121
Total debt	58,466,971
Less current maturities included in current liabilities	(90,394)
Total long-term debt	$ 58,376,577

The Company initially entered into a bank credit facility in December 2001. In January 2006, the Company amended and restated its bank credit facility and, among other things, extended the maturity date to January 2011. Pursuant to the credit agreement (as amended), GeoMet, Inc. (the Borrower) has a $150 million revolving credit facility that permits the Borrower to borrow amounts from time to time based on the available borrowing base as determined in the bank credit facility. The bank credit facility is secured by substantially all of the Company s gas properties and the stock of its subsidiaries. The borrowing base under the bank credit facility is based upon the valuation as of June 30 and December 31 of each year of the Company s gas properties and other factors deemed relevant by the lenders, including Bank of America as agent. The lenders may also request one additional borrowing base re-determination in any fiscal year. In June 2006, the revolving credit facility was amended and restated and increased to $180 million and the borrowing base was increased to $150 million.

As of March 31, 2006, the borrowing base under the bank credit facility was $120 million of which $57.5 million of borrowings were outstanding resulting in a borrowing availability of $62.5. For the three months ended March 31, 2006 we borrowed $12.5 million and made payments of $54 million under the credit facility. As of March 31, 2006 outstanding balances on the revolving credit facility bear interest at either the bank s Adjusted Base Rate, which is the bank s base rate but never less than the Federal Funds Rate plus 0.5%, or the Adjusted LIBOR rate plus a margin of 1.00% to 2.0% based on borrowing base usage.

The Company is subject to certain restrictive financial and non-financial covenants under the bank credit facility, including a minimum current ratio of 1.0 to 1.0, and a maximum rate of EBITDA to interest expense of 2.75 to 1.0, both as defined in the credit facility agreement. As of

March 31, 2006, the Company was in compliance with all of the covenants in the bank credit facility. The bank credit facility matures on January 6, 2011.

Note 8 Common Stock

Effective January 24, 2006, GeoMet s Board of Directors approved a four-for-one common stock split and increased the authorized capital stock of the Company from 10,000,000 shares of common stock at December 31, 2005 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. Prior periods have been adjusted for the stock split.

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GEOMET, INC. AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

On January 30, 2006, we completed a private equity offering of 10,000,000 shares of our common stock, consisting of 2,067,023 shares issued by us and 7,932,977 shares sold by certain of our existing stockholders, to qualified institutional buyers exempt from registration under the Securities Act. We received aggregate consideration of approximately $25.0 million or $12.09 per share. We did not receive any proceeds from the shares sold by certain of our existing 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 bank credit facility and for general corporate purposes. In connection with this offering, on February 7, 2006, we sold an additional 250,000 shares of our common stock to qualified institutional buyers from which we received aggregate consideration of approximately $3.0 million, or $12.09 per share, pursuant to the initial purchaser s option to purchase additional shares. The net proceeds generated from this sale were used to repay a portion of the borrowings under our bank credit facility and for general corporate purposes.

Note 9 Stock Options

Prior to January 1, 2006, stock-based employee compensation was accounted for under the intrinsic value method of Accounting Principles Bulletin No. 25 Accounting for Stock Issued to Employees. The exercise price of the options granted was equal to the estimated market value of the Company s stock at grant date, and therefore, no compensation costs have been recognized. We used the income method on a semi-annual basis to estimate the market value of the Company s stock at grant date.

Effective January 1, 2006, we adopted the fair value recognition provisions of Statement of Financial Accounting Standards 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.

Qualified Stock Options

As of March 31, 2006, we currently have one qualified stock option plan, the 2005 Plan , that authorizes the granting of incentive stock options to key employees. The exercise price of each option may not be less than 100% of the fair market value of a share of common stock on the date of grant. The options have a term of seven years, vest evenly over four years, and become exercisable on each of the first four anniversary dates of issuance. Prior to the effective date of the merger, the option entitled the holder to acquire shares of the Company s majority-owned subsidiary. Effective with the merger of the majority-owned subsidiary into GeoMet, all of the outstanding options under this plan became fully vested and were exchanged for options to acquire common stock of GeoMet. The option tables for the years ended 2004 and 2003 have been converted into equivalent options of GeoMet.

During the three months ended March 31, 2006, the Company recorded a compensation expense accrual in the amount of $205,923 for an employee who exercised his options via a cashless exercise with no mature shares on the date of exercise. The total compensation expense accrual was then allocated to the full cost pool and lease operating expenses in the amount of $102,961 and $102,962, respectively.

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GEOMET, INC. AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

The table below summarizes qualified stock option activity for the three months ended March 31, 2006:

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Life
Outstanding at December 31, 2005	893,324	$ 2.55	3.6
Granted			
Forfeited			
Exercised	162,334	$ 1.52	
Outstanding at March 31, 2006	730,990	$ 2.78	3.48
Options exercisable at March 31, 2006	642,990	$ 3.11	2.12

The total intrinsic value (current market price less option strike price) of options exercised during the three months ended March 31, 2006 was $1.7 million, and the Company received $0.246 million in cash.

Non-Qualified Stock Options

In conjunction with the sale of common stock to certain executive officers of the Company during 2000, we granted these officers options to acquire 400,000 shares of common stock of GeoMet at $2.50 per share. The holders of the options also had a right to be issued additional options to acquire five percent of any additional common stock issued at a price of $2.50 per share. The executive officers were issued options to acquire 600,000 shares in conjunction with the issuance of 12,000,000 common shares in 2003 and were issued options to acquire 200,000 shares in conjunction with the issuance of 4,000,000 common shares in 2004. The options have a term of 10 years and vest ratably over three years and become exercisable on each of the first three anniversary dates of the agreement. As of March 31, 2006, the outstanding options and weighted average remaining contractual life was 1,040,000 shares and 6.8 years, respectively. We determined the fair value of options issued using the minimum value method based on the expected life of the option. For the three months ended March 31, 2006, 160,000 non-qualified stock options were exercised, none forfeited, and none granted. Non-qualified stock options exercisable at March 31, 2006 were 1,040,000. The total intrinsic value (current market price less option strike price) of options exercised during the three months ended March 31, 2006 was $1.7 million, and the Company received $0.4 million in cash.

Note 10 Commitments and Contingencies

Litigation From time to time the Company is a party to litigation in the normal course of business. While the outcome of lawsuits or other proceedings against the Company cannot be predicted with certainty, management does not believe that the adverse effect on its financial condition, results of operations or cash flows of the Company, if any, will be material. As of March 31, 2006, there were no known environmental or other regulatory matters related to the Company s operations which are reasonably expected to result in a material liability to the Company.

El Paso Overriding Royalty Interest Dispute

We filed a claim in the 116th District Court in Dallas County, Texas on June 9, 2004 against El Paso Production Company, CMV Joint Venture and CDX Minerals, LLC seeking a declaratory judgment of our rights under a joint operating agreement covering certain properties in White Oak Creek. We had previously entered into an agreement to sell our interest to CDX, subject to a preferential right to purchase held by El Paso, which El Paso subsequently exercised. A dispute arose as to whether the preferential right granted under the agreement applied to overriding royalty interests and other related interests. We have asserted that the preferential right to purchase does not include overriding royalty interests and that we are entitled to retain all overriding royalty

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GEOMET, INC. AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

interests we possess under the agreement. The trial court rendered judgment in our favor, and El Paso has appealed the decision of the trial court. While we believe that we are entitled to retain these interests, a judgment against us would result in our being required to sell the overriding royalty interest to El Paso for a price of approximately $10.5 million; however, this amount would be reduced by any proceeds we have received from production since the effective date of the sale.

CNX Surface Use Dispute

We and Pocahontas Mining Limited Liability Company (PMC) filed a claim in the Circuit Court of Buchanan County, Virginia on May 26, 2006 against CNX Gas Company LLC (CNX) seeking a temporary and permanent injunction as well as a declaration of our rights under a right-of-way agreement that we entered into with PMC, the surface owner. We are in the process of constructing a 12-mile pipeline, a portion of which traverses this right-of-way to connect with and transport our gas to the Jewell Ridge Pipeline. CNX has claimed that it has the exclusive right to transport gas across the acreage in question and that our right-of-way is invalid. CNX has gated certain access roads to the acreage and requested that we remove our contractor s equipment from the property. The Circuit Court of Buchanan County, Virginia conducted evidentiary hearings on June 15, 2006 and July 6, 2006. At the hearings the court 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. In the interim period, the court has ordered CNX to allow us access to the property over and across the existing roads. 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.

We believe that our right-of-way agreement is valid and enforceable and that we will prevail in our lawsuit; however, 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 our gas from the Pond Creek field to market for an extended period of time. If we are unable to deliver our gas from the Pond Creek field to market for a prolonged period of time, our financial position, results of operations and cash flow will be materially adversely affected.

Note 11 Related Party Transactions

On July 21, 2003, GeoMet loaned the Chief Financial Officer $250,000 to provide liquidity in connection with a divorce settlement so that the executive could retain ownership of his common stock. The full recourse loan accrues interest at an annual rate of 5.87% and becomes due and payable on the earlier of April 14, 2009, six months after the holder ceases to be an employee or the occurrence of a Triggering Transaction as defined in the note agreement. The note was paid in full on January 2006 concurrent with the private offering discussed in note 9.

Note 12 Income Taxes

We record our income taxes using an asset and liability approach in accordance with the provisions of the SFAS No. 109, *Accounting for Income Taxes*. This results in the recognition of deferred tax assets and liabilities using estimated effective tax rates 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.

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GEOMET, INC. AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

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 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.

Deferred income tax was increased by $405,772 during the three months ended March 31, 2006 because of certain state taxes that were not previously included in prior periods.

Note 13 Subsequent Events

On July 10, 2006, the Company filed Amendment No. 4 to Form S-1 (Registration No. 333-131716) with the Securities and Exchange Commission to register for sale the shares of common stock issued in the private offering discussed in note 9. Also on July 10, 2006, the Company filed Amendment No. 1 to Form S-1 (Registration No. 333-134070) to register shares of its common stock for sale in an initial public offering.

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Appendix A

DeGolyer and MacNaughton

5001 Spring Valley Road

Suite 800 East

Dallas, Texas 75244

APPRAISAL REPORT

on

PROVED RESERVES

as of

DECEMBER 31, 2005

on

CERTAIN PROPERTIES

owned by

GEOMET, INC.

EXECUTIVE SUMMARY

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DeGolyer and MacNaughton

5001 Spring Valley Road

Suite 800 East

Dallas, Texas 75244

APPRAISAL REPORT

on

PROVED RESERVES

as of

DECEMBER 31, 2005

on

CERTAIN PROPERTIES

owned by

GEOMET, INC.

EXECUTIVE SUMMARY

FOREWORD

Scope of Investigation This report presents an appraisal, as of December 31, 2005, of the extent and value of the proved natural gas reserves of certain coal bed methane properties owned by Geomet, Inc. (Geomet). The reserves estimated in this report are in the White Oak Creek and Gurnee fields located in Bibb, Jefferson, Tuscaloosa, Walker, and Shelby Counties in Alabama and in the Pond Creek field located in McDowell County, West Virginia and Buchanan County, Virginia. The properties appraised are listed in detail in the appendix bound with our report entitled Appraisal Report on Proved Reserves as of December 31, 2005 on Certain Properties owned by Geomet, Inc.

Reserves estimated in this report are expressed as gross and net reserves. Gross reserves are defined as the total estimated petroleum to be produced from these properties after December 31, 2005. Net reserves are defined as that portion of the gross reserves attributable to the interests owned by Geomet after deducting royalties and interests owned by others.

This report also presents values for proved reserves using prices and costs provided by Geomet. In general, prices and costs were held constant for the life of the properties. A detailed explanation of the future price and cost assumptions is included in the Valuation of Reserves section of this report.

Values of proved reserves in this report are expressed in terms of estimated future gross revenue, future net revenue, and present worth. Future gross revenue is that revenue which will accrue to the appraised interests from the production and sale of the estimated net reserves. Future net revenue is calculated by deducting estimated production taxes, ad valorem taxes, operating expenses, and capital costs from the future gross revenue. Operating expenses include field operating expenses, transportation expenses, compression charges, and an allocation of overhead that directly relates to production activities. Future income tax expenses were not taken into account in the preparation of these estimates. Present worth is defined as future net revenue discounted at a specified arbitrary discount rate compounded monthly over the expected period of realization. In this report, present worth values using a discount rate of 10 percent are reported in detail.

Estimates of gas reserves and future net revenue should be regarded only as estimates that may change as further production history and additional information become available. Not only are such reserves and revenue estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Authority This report was prepared at the request of Mr. J. Darby Seré, Chairman, President, and Chief Executive Officer, Geomet.

Source of Information Data used in the preparation of this report were obtained from Geomet and from public sources. Additionally, this information includes data supplied by Petroleum Information/Dwights LLC;

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 In the preparation of this report we have relied, without independent verification, upon information furnished by Geomet with respect to its property interests, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination of the properties was not considered necessary for the purposes of this report.

CLASSIFICATION of RESERVES

Petroleum reserves included in this report are classified as proved and are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs as of the date the estimate is made, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. Proved reserves classifications used in this report are in accordance with the reserves definitions of Rules 4 10(a) (1) (13) of Regulation S X of the Securities and Exchange Commission (SEC) of the United States. The petroleum reserves are classified as follows:

Proved oil and gas reserves Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(iii) Estimates of proved reserves do not include the following: (A) oil that may become available from known reservoirs but is classified separately as indicated additional reserves ; (B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite, and other such sources.

Proved developed oil and gas reserves Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as proved developed reserves only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved undeveloped reserves Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

ESTIMATION of RESERVES

Estimates of reserves were prepared by the use of geological and engineering methods generally accepted by the petroleum industry. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

White Oak Creek Field The properties evaluated in the White Oak Creek field in Alabama produce from the Pratt, New Castle, Mary Lee, and Black Creek coal seams and are located in the western portion of the Warrior basin. The composite thickness of these coal seams in this area varies from 10 feet to more than 15 feet. The coal in this area is water saturated and requires stimulation and a dewatering period before maximum gas rates are achieved. This area is predominately being developed on an 80-acre well spacing.

Production-decline curves for all of the coal bed methane wells in the immediate six township areas surrounding these properties, using production data available as of the date of the report, were analyzed to determine the typical production profile for the wells in this area. The producing rates for wells in this area typically incline for several years as the area is being dewatered. The rates will then either decline immediately or will remain flat for several years and then decline depending on the rate of dewatering and, consequently, the drawdown in reservoir pressure.

The volumetric method was used to estimate original gas in place (OGIP) for each of the 80-acre tracts in which Geomet owns an interest. Isopach maps were used to estimate coal volume, and the gas content of the coal was obtained from canister tests performed on various cores taken in the area.

Estimates of ultimate recovery were obtained after applying recovery factors to OGIP. Recovery factors were based on analogy with older wells in the area for which the producing trends disclosed a reliable decline that could be extrapolated to an economic limit.

Proved developed producing reserves were estimated for the older wells by extrapolating production-decline curves to an economic limit based on current economic conditions. For producing wells where the rates of production were inclining or flat, the volumetric method was used to estimate the reserves and the type curves were used to project the future rates of production.

Proved developed nonproducing reserves were estimated for certain wells that have been drilled but are not currently on production. The volumetric method was used to estimate the reserves for these wells and the type curves were used to project the future rates of production.

Proved undeveloped reserves were estimated using the volumetric method and the type curves were used to project the future rates of production for the wells to be drilled on these properties.

Gurnee Field All of the properties evaluated in the Gurnee field in Alabama produce from the Gholson, Coke, Jones/Alice, Big Bone/J, and Big Dirty coal seams and are located in the Cahaba basin. The composite thickness of these coal seams in this area varies from 25 feet to more than 85 feet. Average composite thickness is approximately 50 feet. The coal in this area is water saturated and requires stimulation and a dewatering period before maximum gas rates are achieved. This area is predominately being developed on an 80-acre well spacing.

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Production-decline curves for all of the coal bed methane wells in the immediate five township areas surrounding Geomet s Gurnee properties, using production data available as of the date of the report, were analyzed to determine the typical production profile for the wells in this area. The producing rates for wells in this area typically incline for several years as the area is being dewatered. The rates will then either decline immediately or will remain flat for several years and then decline depending on the rate of dewatering and, consequently, the drawdown in reservoir pressure.

The volumetric method was used to estimate OGIP for each of the 80-acre tracts in which Geomet owns an interest. Isopach maps were used to estimate coal volume, and the gas content of the coal was obtained from canister tests performed on various cores taken in the area.

Estimates of ultimate recovery were obtained after applying recovery factors to OGIP. Recovery factors were based on experience and general knowledge of established coal bed methane projects in the Cahaba basin and adjacent Black Warrior basin.

Proved developed producing reserves were estimated for the older wells by extrapolating production-decline curves to an economic limit based on current economic conditions. For producing wells where the rates of production were inclining or flat, the volumetric method was used to estimate the reserves and the type curves were used to project the future rates of production.

Proved developed nonproducing reserves were estimated for certain wells that have been drilled but are not currently on production. The volumetric method was used to estimate the reserves for these wells and the type curves were used to project the future rates of production.

Proved undeveloped reserves were estimated using the volumetric method and the type curves were used to project the future rates of production for the wells to be drilled on these properties.

Pond Creek Field All of the properties in West Virginia and Virginia evaluated in this report produce from the Pocahontas coal seams 1 through 10 in the Central Appalachian basin. The composite thickness of the coal seams in this area varies from 15 feet to more than 35 feet. The coal in this area is partially water saturated and requires stimulation and a dewatering period before maximum gas rates are achieved. This area is predominately being developed on 80-acre well spacing.

Production-decline curves for coal bed methane wells in McDowell County in West Virginia and Buchanan County in Virginia were analyzed, using production data available as of the date of the report, to determine the typical production profile for the wells in this area. The gas producing rates in this area typically incline for several years as the area is being dewatered. The rates will then either decline immediately or will remain flat for several years and then decline depending on the rate of dewatering and, consequently, the drawdown in reservoir pressure.

The volumetric method was used to estimate the OGIP for each 80-acre tract in which Geomet owns an interest. Isopach maps were used to estimate coal volume. Gas content of the coal was obtained from canister tests performed on cores taken in the area.

Estimates of ultimate recovery were obtained after applying recovery factors to OGIP. Recovery factors were based on experience and general knowledge of established coal bed methane projects in the Central Appalachian basin.

Proved developed producing reserves were estimated for the older wells by extrapolating production-decline curves to an economic limit based on current economic conditions. For producing wells where the rates of production were inclining or flat, the volumetric method was used to estimate the reserves and the type curves were used to project the future rates of production.

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Proved developed nonproducing reserves were estimated for the wells that had been drilled but were not on production as of December 31, 2005, and for future coal seam completions in producing wells. The volumetric method was used to estimate the reserves, and type curves were used to project the future rates of production.

Proved undeveloped reserves were estimated using the volumetric method, and type curves were used to project the future rates of production for wells to be drilled.

In the preparation of this report, gross production estimated through December 31, 2005, was deducted from gross ultimate recovery to arrive at the estimates of gross reserves. This required that the production rates be estimated for 1 month, since production data from certain properties were available only through November 2005. Data available from wells drilled on the appraised properties through December 31, 2005, are included herein. The development status represents the status applicable on December 31, 2005.

Gas volumes estimated herein are expressed as wet gas and sales gas. Wet gas is defined as the total gas to be produced before reductions for volume loss due to fuel and flare consumption and reduction for plant processing. Sales gas is defined as that portion of the wet gas to be delivered into a gas pipeline for sale after reduction for fuel usage, flare, and shrinkage resulting from field separation and plant processing. Gross gas volumes are reported as wet gas. Net gas volumes are reported as sales gas. All gas volumes are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at the legal pressure base of the state in which the property is located.

Shrinkage factors, based on historic data, of 6.1 percent for production from White Oak Creek field, 6.07 percent for production from Pond Creek, and 6.38 percent for production from Gurnee were used to estimate sales-gas volume.

The following table presents estimates of the proved reserves, as of December 31, 2005, of the properties appraised, expressed in millions of cubic feet (MMcf):

	Gross Wet-Gas Reserves (MMcf)	Net Sales-Gas Reserves (MMcf)
Proved Developed Producing	323,549	169,764
Proved Developed Nonproducing	34,422	25,375
Proved Undeveloped	96,732	67,372
Total Proved	**454,703**	**262,511**

VALUATION of RESERVES

This report has been prepared using initial prices and costs specified by Geomet. Future prices were estimated using guidelines established by the SEC and the Financial Accounting Standards Board (FASB).

Revenue values in this report were estimated using the initial prices and costs provided by Geomet. The following assumptions were supplied by Geomet and used for estimating future prices and costs in this report:

Natural Gas Prices

Gas price differentials for each property were provided by Geomet. The prices for gas from each field were calculated using these differentials to a Henry Hub price of $9.52 per million British thermal units (MMBtu) and were held constant for the lives of the properties. The weighted average price over the lives of the properties in the White Oak Creek field is $9.60 per thousand cubic feet (Mcf). The

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weighted average price over the lives of the properties in the Gurnee field is $9.49 per Mcf. The weighted average price over the lives of the properties in the Pond Creek field is $9.88 per Mcf.

Operating Expenses and Capital Costs

Estimates of operating expenses and capital costs based on current costs were used for the life of the properties with no increases in the future based on inflation. In certain cases future costs, either higher or lower than current costs, may have been used because of anticipated changes in operating conditions. Future capital expenditures were estimated using December 31, 2005 values and were not adjusted for inflation.

The estimated future revenue to be derived from the production and sale of the proved reserves, as of December 31, 2005, of the properties appraised is summarized as follows:

	Proved			
	Developed Producing	**Developed Nonproducing**	**Undeveloped**	**Total Proved**
Future Gross Revenue, M$	1,641,921	241,471	652,887	2,536,279
Production and Ad Valorem Taxes, M$	76,245	12,860	28,981	118,086
Operating Expenses, M$	236,797	11,990	96,542	345,329
Capital Costs, M$	0	7,125	69,172	76,297
Future Net Revenue*, M$	1,328,879	209,495	458,192	1,996,566
Present Worth at 10 Percent*, M$	657,426	73,787	148,942	880,155

* Future income taxes have not been taken into account in the preparation of these estimates.

Table 1 presents a summary of estimated net proved reserves by field and reserves classification and in total. Table 2 presents a summary of estimated revenues and expenditures from net proved reserves by field and reserves classification and in total.

In our opinion, the information relating to estimated proved reserves, estimated future net revenue from proved reserves, and present worth of estimated future net revenue from proved gas reserves contained in this report has been prepared in accordance with Paragraphs 10 13, 15, and 30(a) (b) of Statement of Financial Accounting Standards No. 69 (November 1982) of the FASB and Rules 4 10(a) (1) (13) of Regulation S X and Rule 302(b) of Regulation S K of the SEC; provided, however, that (i) certain estimated data have not been provided with respect to changes in reserves information (ii) future income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature or information beyond the scope of our report, we are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

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SUMMARY and CONCLUSIONS

Geomet owns interests in certain properties in the White Oak Creek and Gurnee fields located in Bibb, Jefferson, Tuscaloosa, Walker, and Shelby Counties in Alabama and in the Pond Creek field located in McDowell County, West Virginia and Buchanan County, Virginia. The estimated net proved reserves of the properties appraised, as of December 31, 2005, are summarized as follows, expressed in millions of cubic feet (MMcf):

	Net Sales-Gas Reserves (MMcf)
Proved Developed Producing	169,764
Proved Developed Nonproducing	25,375
Proved Undeveloped	67,372
Total Proved	**262,511**

Estimated revenue and costs attributable to Geomet s interests in the proved reserves, as of December 31, 2005, of the properties appraised under the aforementioned assumptions concerning future prices and costs are summarized as follows:

	Proved			
	Developed Producing	Developed Nonproducing	Undeveloped	Total Proved
Future Gross Revenue, M$	1,641,921	241,471	652,887	2,536,279
Production and Ad Valorem Taxes, M$	76,245	12,860	28,981	118,086
Operating Expenses, M$	236,797	11,990	96,542	345,329
Capital Costs, M$	0	7,125	69,172	76,297
Future Net Revenue*, M$	1,328,879	209,495	458,192	1,996,566
Present Worth at 10 Percent*, M$	657,426	73,787	148,942	880,155

* Future income taxes have not been taken into account in the preparation of these estimates.

All gas reserves in this report are expressed at a temperature base of 60 °F and the legal pressure base of the state in which the property is located.

Submitted,

/s/ DeGOLYER AND MacNAUGHTON

DeGOLYER and MacNAUGHTON

SIGNED: April 6, 2006

[SEAL]

/S/ JAMES TERRACIO, P.E.

James Terracio, P.E.

Senior Vice President

DeGolyer and MacNaughton

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TABLE 1

ESTIMATED NET PROVED RESERVES

as of

DECEMBER 31, 2005

from

CERTAIN PROPERTIES

owned by

GEOMET, INC.

	Proved			
Field	**Developed Producing Sales Gas (MMcf)**	**Developed Nonproducing Sales Gas (MMcf)**	**Undeveloped Sales Gas (MMcf)**	**Total Proved Sales Gas (MMcf)**
Gurnee	88,787	23,730	32,545	**145,062**
Pond Creek	78,256	1,608	34,594	**114,458**
White Oak Creek	2,721	37	233	**2,991**
Grand Total	**169,764**	**25,375**	**67,372**	**262,511**

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TABLE 2

ESTIMATED REVENUE from NET PROVED RESERVES

as of

DECEMBER 31, 2005

from

CERTAIN PROPERTIES

owned by

GEOMET, INC.

Field Reserves Classification	Future Gross Revenue (M$)	Production and Ad Valorem Taxes (M$)	Total Operating Expenses (M$)	Capital Costs (M$)	Future Net Revenue (M$)	Present Worth at 10 Percent (M$)
Gurnee						
Developed Producing	842,712	45,675	88,628	0	708,408	352,568
Developed Nonproducing	225,236	12,208	9,299	6,880	196,849	68,682
Undeveloped	308,903	16,742	37,978	36,903	217,281	75,374
Total Proved	**1,376,851**	**74,625**	**135,905**	**43,783**	**1,122,538**	**496,624**
Pond Creek						
Developed Producing	773,090	29,154	148,169	0	595,767	288,803
Developed Nonproducing	15,886	633	2,691	245	12,316	4,927
Undeveloped	341,750	12,118	58,564	32,269	238,798	72,535
Total Proved	**1,130,726**	**41,905**	**209,424**	**32,514**	**846,881**	**366,265**
White Oak Creek						
Developed Producing	26,119	1,416	0	0	24,704	16,055
Developed Nonproducing	349	19	0	0	330	178
Undeveloped	2,234	121	0	0	2,113	1,033
Total Proved	**28,702**	**1,556**	**0**	**0**	**27,147**	**17,266**
Total Developed Producing	**1,641,921**	**76,245**	**236,797**	**0**	**1,328,879**	**657,426**
Total Developed Nonproducing	**241,471**	**12,860**	**11,990**	**7,125**	**209,495**	**73,787**
Total Undeveloped	**652,887**	**28,981**	**96,542**	**69,172**	**458,192**	**148,942**
Grand Total Proved	**2,536,279**	**118,086**	**345,329**	**76,297**	**1,996,566**	**880,155**

Note: Future income tax expenses were not taken into account in the preparation of these estimates.

5,000,000 Shares

Common Stock

Prospectus

July 27, 2006

Banc of America Securities LLC

A.G. Edwards

Raymond James

Until August 21, 2006 (25 days after the commencement of this offering), all dealers that buy, sell or trade the common stock may be required to deliver a prospectus, regardless of whether they are participating in this offering. This is in addition to the dealers obligation to deliver a prospectus when acting as underwriters and with respect to their unsold allotments or subscriptions.