GeoMet, Inc.
Form 10-K
March 20, 2007
Table of Contents

Index to Financial Statements

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2006

or

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission file number 000-52155

GeoMet, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**76-0662382**
State or other jurisdiction of incorporation or organization	**(I.R.S. Employer Identification No.)**
909 Fannin, Suite 1850, Houston, Texas 77010	**77010**

(Address of principal executive offices)	(Zip Code)

Registrant s telephone number, including area code

(713) 659-3855

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common stock, par value $0.001 per share	**NASDAQ Global Market**

Securities registered pursuant to Section 12(g) of the Act

Title of Class

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ¨ No x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ¨	Accelerated filer ¨	Non-accelerated filer x

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x

As of March 1, 2007, 38,680,713 shares of the registrant s common stock, par value $0.001 per share, were outstanding. The registrant was not a publicly reporting entity as of the last business day of the most recently completed second quarter and, therefore, cannot calculate the aggregate market value of its voting and non-voting common equity held by non-affiliates.

Table of Contents

Index to Financial Statements

GeoMet, Inc.

Form 10-K

TABLE OF CONTENTS

Table of Contents

Index to Financial Statements

CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

Various statements in this annual report, 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 annual report 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 annual report 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 annual report. All forward-looking statements speak only as of the date of this annual report. 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.

All references in this annual report to the Company , GeoMet , we , us or our are to GeoMet Inc. and our wholly-owned Subsidiaries. Unless otherwise noted, all information in this annual report relating to natural gas reserves and the estimated future net cash flows attributable to those reserves are based on estimates prepared by independent engineers and are net to our interest.

3

Table of Contents

Index to Financial Statements

GLOSSARY OF NATURAL GAS AND COALBED METHANE TERMS

The following is a description of the meanings of some of the oil and natural 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, natural 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 natural gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known reservoir.

Table of Contents

Index to Financial Statements

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 non-GAAP 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 natural 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.

Natural 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 natural gas during the test period, corrected to standard temperature and pressure (the measured natural gas), (ii) the lost natural 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 natural gas, which is determined by measuring the natural 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.

Dth. Decatherm is 10 therms and 1 therm is equivalent to 100,000 btu s at 59 degrees.

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

Table of Contents

Index to Financial Statements

of federal income taxes, a non-GAAP measure. 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 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 natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Shut in. Stopping an oil or natural 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 natural 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.

Table of Contents

Index to Financial Statements

PART I

Item 1. *Business*

History of GeoMet

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

During the period 1985 through 1993, 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.

About GeoMet

We are engaged in the exploration, development, and production of natural gas from coal seams (coalbed methane or CBM) and gas marketing. Our principal operations and producing properties are located in the Cahaba Basin in Alabama and the central Appalachian Basin in West Virginia and Virginia. At December 31, 2006, we controlled a total of approximately 280,000 net acres of coalbed methane and oil and natural gas 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 central Appalachian Basin, and we also control the balance of 203,000 net acres of coalbed methane and oil and natural gas development rights primarily in Alabama, 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 633 additional drilling locations. We operate in two segments, natural gas exploration, development and production, exclusively within the continental United States and British Columbia and gas marketing in the United States.

Table of Contents

Index to Financial Statements

At December 31, 2006, we had 325.7 Bcf of estimated proved reserves with a PV-10 of approximately $526 million using gas prices in effect at such date. See Selected Financial Data Reconciliation of Non-GAAP Financial Measures for additional information regarding PV-10. Our estimated proved reserves were 100% coalbed methane and 75% proved developed. In 2006 our net gas sales averaged approximately 17,064 Mcf per day. For 2006, our total capital expenditures were approximately $81 million, and our development expenditures for the development of the Gurnee and Pond Creek fields were approximately $67.2 million. We intend to spend approximately $57 million in 2007 for development expenditures in the Gurnee and Pond Creek fields, a 15% decrease from 2006. For 2007, we estimate that our total capital expenditures will be approximately $69 million.

Areas of Operation

Cahaba Basin

We have the development rights to approximately 42,000 net CBM acres throughout the Cahaba Basin of central Alabama, which is adjacent to the Black Warrior Basin. At December 31, 2006, approximately 59% of our estimated proved reserves, or 193.1 Bcf, were located in the Gurnee field within the Cahaba Basin, of which approximately 78% were classified as proved developed. At December 31, 2006, we had developed approximately 31% of our Cahaba Basin CBM acreage. We own a 100% working interest in the area and are the operator. As of December 31, 2006, we had 194 net productive wells in the Gurnee field. Net daily sales of gas averaged approximately 5,343 Mcf for 2006. At December 31, 2006, our undeveloped CBM acreage in the Cahaba Basin contained 346 additional drilling locations, based predominantly on 80-acre spacing. In 2007, we intend to spend approximately $34 million of our capital expenditure budget to develop and drill approximately 52 wells and expand our facilities in the Cahaba Basin. We intend to drill at least 50 wells annually in the Cahaba Basin over the next several 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 33 core holes have been drilled and over 600 gas desorption tests have been conducted on our acreage to determine the gas content of the coal and to define the coalbed methane resource under a substantial portion of the acreage in our leasehold position.

We have constructed and operate an approximate 38.5-mile pipeline from the Cahaba Basin to the Black Warrior River for the disposal of produced water under a permit issued by the Alabama Department of Environmental Management. This pipeline has a design capacity of approximately 45,000 barrels of water per day. In October 2006, we executed a series of agreements with a privately held company relating to our operations in the Cahaba Basin, under which we agreed to designate up to 50% of the pipeline s capacity to dispose of produced water from the company s operations in the Gurnee field. Our fees earned under the agreements will initially be $0.35 per barrel of untreated produced water but will decline to $0.20 per barrel of treated produced water on or about September 12, 2007. The disposal fees we generate will be included in other revenues. 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 our disposal pipeline and water treatment facility will meet all of our future water disposal requirements for the Gurnee field.

Additionally, under these agreements, we have secured firm capacity rights on a high pressure gas gathering pipeline which connects into Enbridge s Magnolia Pipeline System. The acquired rights entitle us to transport approximately 40 million cubic feet per day of coalbed methane gas at a fee of $0.05 per MMbtu actually gathered through the pipeline. We do not anticipate utilizing this capacity in the immediate future. This agreement provides us with a second outlet for our gas produced from the Gurnee field. Together with our existing capacity on the Southern Natural Gas Bessemer Calera lateral, our total gas takeaway capacity is expected to meet all of our future requirements.

Table of Contents

Index to Financial Statements

We control and operate a 17.3-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.

Central Appalachian Basin

In the central 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, 2006, approximately 40% of our estimated proved reserves, or 130.0 Bcf, were located within the Pond Creek field, of which approximately 68% were classified as proved developed. We own a 100% working interest in the area and are the operator. As of December 31, 2006, we had 194 net productive wells in the Pond Creek field. Net daily sales of gas averaged approximately 10,531 Mcf for 2006. As of December 31, 2006, our undeveloped CBM acreage in the Pond Creek field contained 287 additional drilling locations based predominantly on 60-acre spacing. In 2007, we intend to spend approximately $23 million of our capital expenditure budget to develop and drill approximately 40 wells in the Pond Creek field. We intend to drill at least 40 wells annually in the Pond Creek field over the next several 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. Prior mining activity revealed that these coal groups are gas rich. A total of 41 core holes have been drilled on and in the area of our acreage in the central 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 is cancellable by either party upon 30 days notice beginning 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 approximately $6 million to interconnect with Jewell Ridge Pipeline, a new interstate pipeline. The 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 Spectra Energy, constructed and operates the Jewell Ridge Pipeline. In March 2006, we executed a precedent agreement with ETNG that, subject to satisfaction of certain conditions, obligated the parties to enter into two long-term firm transportation agreements, which become effective when our pipeline is in service, having maximum daily quantities of 15,000 decatherms and 10,000 decatherms and primary terms of 15 years and 10 years, respectively. We expect our pipeline to be in service by April 1, 2007.

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 central Appalachian Basin. We have drilled two test wells and four core holes in that area.

British Columbia

Our Peace River Project is comprised of approximately 36,687 gross acres and 18,343 net acres along the Peace River near Hudson s Hope, British Columbia. We are conducting operations on this project through an exploration and development agreement with a group of third parties. We have earned a 50% working interest in

Table of Contents

Index to Financial Statements

this leasehold by spending $7.2 million on an evaluation program. 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. Prior to 2006, we drilled and completed two production test wells and recompleted a third production test well and a water disposal well. During 2006, we drilled four production test wells and a water disposal test well. We are currently conducting testing operations on these wells. In 2007, we intend to spend approximately $2.0 million of our capital expenditure budget to continue the evaluation and exploration of 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, 2006, 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 19 exploration or production test wells and two water disposal wells. We have also conducted 71 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 continue to pursue 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.

Table of Contents

Index to Financial Statements

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.

Strategy

Our objective is to increase stockholder value by investing capital to increase our reserves, production, cash flow, and earnings. We have recently engaged Merrill Lynch & Co. to evaluate and advise us on potential strategic opportunities or alternatives to increase our stockholder value. We intend to focus on the following strategies:

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

- Exploit our existing resource base by 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 $90 million was available for borrowing at December 31, 2006.

Competitive Strengths

CBM Is Our Primary Business. We primarily explore for, develop, and produce CBM gas. 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 for the three-year period ended December 31, 2006 have been significantly below the industry average as published by John F. Herold, an independent third party.

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

Table of Contents

Index to Financial Statements

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 typically have inclining production rates early in their lives 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 22-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 2,700 CBM wells worldwide since 1977.

Large Inventory of Organic Growth Opportunities. We have a total of over 280,000 net acres of CBM and oil and natural gas 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 central Appalachian Basin provides us with a total of 633 additional drilling locations.

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

Minimal Water Disposal Issues. Unlike many CBM projects, water disposal is not a significant issue for us. In the Gurnee field, we have a pipeline in place to transport produced water for disposal into the Black Warrior River. The Pond Creek field 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 drill on our properties and fund our capital budgets depends, to a large extent, upon our ability to generate cash flow from operations at or above current levels and maintain borrowing capacity at or near current levels under our revolving credit facility, or 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, lower than expected production rates 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.

Marketing and Customers

We market substantially all of our gas through Shamrock Energy LLC, which became our wholly owned subsidiary on January 1, 2007, under a natural gas purchase agreement. The purchase agreement calls for Shamrock to purchase and us to sell gas produced from all of our major properties. In addition, 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 sold, less a fee for Shamrock s services ranging from $0.03 to $0.045 per MMBtu purchased.

Table of Contents

Index to Financial Statements

On June 14, 2006, we entered into an option agreement with Jon M. Gipson, the president of Shamrock, pursuant to which we had the right to acquire all of the outstanding equity interests and assets of Shamrock. 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, the termination date of the Shamrock purchase option, (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 entered into during the option period that require such guaranties, up to an aggregate of $1,500,000, and (iv) to advance Shamrock up to an additional $50,000 as may be required to cover certain expenses of Shamrock prior to January 31, 2007.

We exercised the Shamrock purchase option on January 1, 2007, at which time we provided Mr. Gipson an at-will employment position with us. Also, on March 9, 2007, we caused Shamrock to distribute to Mr. Gipson approximately $22,500, which equals 50% of the net profits generated by Shamrock from August 1, 2006 through January 1, 2007. This amount was accrued at December 31, 2006 as a dividend payable to Mr. Gipson. No additional consideration was paid as a result of our exercise of this option.

In accordance with FIN 46(R), we consolidated Shamrock into our financial statements, effective August 1, 2006. We did not have any voting interest in Shamrock prior to January 1, 2007 and as a result the consolidation of Shamrock did not have a material impact on our results of operations for year ended December 31, 2006. Other than the Shamrock customers that we have provided guarantees to on behalf of Shamrock, the remainder of Shamrock s customers have no recourse against us. Our potential losses were limited to the current advance of $90,000 and the amounts outstanding under the existing guarantees ($1,160,000) which have not been recorded as a liability as of December 31, 2006. As of December 31, 2006, $3,387,118 of assets and $3,387,118 of liabilities have been included in our audited consolidated balance sheet as a result of applying FIN 46(R) to Shamrock, a variable interest entity. Over 99% of the assets and liabilities are current.

Segment Information

We are engaged in the exploration, development and production of coal bed methane primarily in the United States and Canada. The variable interest entity consolidation of Shamrock LLC for the period from August 1, 2006 through December 31, 2006 (see Note 4 of the audited consolidated financial statements) added a gas marketing activity that added a second reportable segment to our core business of natural gas exploration, development and production.

Using guidelines set forth in SFAS No. 131, *Disclosures about Segments of an Enterprise and Related Information*, we have identified two reportable segments; (1) exploration, development and production of natural gas and (2) marketing natural gas.

Information concerning our business activities is summarized as follows:

	Natural Gas Exploration & Production	Marketing Natural Gas	Eliminations	Total
As of and for the year ended December 31, 2006:				
Revenues from external customers	$ 45,092,949	$ 13,043,598	$	$ 58,136,547
Intersegment revenues	22,551,525		(22,551,525)	
Operating income (loss)	31,305,258	(109)		31,305,149
Total assets	$ 331,807,648	$ 9,266,426	$ (5,879,308)	$ 335,194,766

All sales and operating income occurred in the United States, except for a $624,151 operating loss in Canada. Natural gas exploration and production cash capital expenditures were $73,344,670 in the United States and $5,715,938 in Canada. Marketing natural gas is not capital intensive and there were no capital expenditures during the reporting period. We sell all of our gas production to Shamrock Energy, our natural gas marketing

Table of Contents

Index to Financial Statements

subsidiary, and all intersegment revenues are related to Shamrock. For the years ended December 31, 2006 and 2005 and 2004, Shamrock, which became our wholly owned subsidiary on January 1, 2007, purchased approximately 99% of our natural gas production. Due to the availability of other purchasers, we do not believe that the loss of our current purchasers would adversely affect our results of operations.

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 generally highly fragmented and not dominated by any single producer except in the immediate area of our Virginia development operations, where we believe there is one dominate producer that controls a substantial portion of the market. 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.

Governmental Regulations

Our coalbed methane exploration and production operations are subject to significant federal, state, and local laws and regulations governing the gathering and transportation of our gas production across state and federal boundaries. The following is a summary of some of the existing regulations to which our operations in the United States are subject.

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 own a pipeline in Alabama that provides intrastate natural gas transportation as defined by the Alabama Public Service Commission (APSC). The APSC regulates gas pipelines that transport gas on an intrastate basis in situations where the gas has been cleaned and pressurized to the point that it is ready for sale. All pipeline systems in Alabama must be constructed, operated and maintained to be in compliance with the defined federal minimum safety standards. The APSC has not enacted its own regulations relating to pipeline safety. Instead, it enforces the U.S. Department of Transportation Office of Pipeline Safety Regulations, including as to reporting, design, construction, and operating requirements of the pipeline. We are inspected annually by the APSC to ensure we are in compliance with the regulations.

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

Table of Contents

Index to Financial Statements

traditional tests the FERC has used to establish a pipeline s status as a gatherer not subject to the FERC s 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 natural gas sales 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

Table of Contents

Index to Financial Statements

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 on the oil and gas industry, in general.

Table of Contents

Index to Financial Statements

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 contributing 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 material 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.

Table of Contents

Index to Financial Statements

Employees

At December 31, 2006, we had 77 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. At December 31, 2006 we did not have any personnel working as contractors.

Corporate Offices

We lease our corporate offices at 909 Fannin, Suite 1850, Houston, Texas 77010. Effective November 1, 2006, we increased our office space to 9,041 square feet and our lease agreement provides for a monthly rental of $16,598 per month through October 2009. Our technical and operational headquarters are located at 5336 Stadium Trace Parkway, Suite 206, Birmingham, Alabama 35244.

Code of Ethics

In November 2006, we adopted an amended Corporate Code of Business Conduct and Ethics for all of our employees, including the Chief Executive Officer and Chief Financial Officer. A copy of our Corporate Code of Business Conduct and Ethics is filed as an exhibit to this Form 10-K and is also available on our website at *www.geometinc.com*.

Available Information

General information about us can be found on our website at *www.geometinc.com*. Our annual report on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, as well as any amendments and exhibits to those reports, are available free of charge through our website as soon as reasonably practicable after we file or furnish them to the Securities and Exchange Commission and are also available on the SEC s website www.sec.gov.

Item 1A. ***Risk Factors***

If any of the following risks develop into actual events, our business, financial condition, results of operations, cash flows, strategies and prospects could be materially adversely affected.

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.

Table of Contents

Index to Financial Statements

Many of these factors may be beyond our control. Because all of our estimated proved reserves as of December 31, 2006 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, 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.

Table of Contents

Index to Financial Statements

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.

Our ability to market the gas we produce depends in substantial part on the availability and capacity of pipeline 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 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 currently 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 is cancellable by either party on 30 days written notice beginning on April 30, 2007. We are in the process of constructing a 12-mile pipeline to transport the natural gas we produce from the Pond Creek field into the Jewell Ridge Pipeline, which is owned and operated by East Tennessee Natural Gas, LLC, and a subsidiary of Spectra Energy. Upon completion of our new pipeline, we will have an alternative to the Cardinal States gathering system as a means to transport our gas to market. Pocahontas Mining Limited Liability Company (PMC) owns a portion of the land through which our new pipeline has been constructed and has granted us an easement to construct the pipeline on this land under a right-of-way agreement.

We have had ongoing legal disputes with CNX Gas Company LLC (CNX), the parent company of Cardinal States, as to whether or not the pipeline right-of-way granted to us by PMC is valid and whether CNX has the exclusive right to transport natural gas across PMC s property, as well as seeking a partition of the surface of a 32-acre tract of land that we and CNX both own undivided interests in the surface of the acreage,

Table of Contents

Index to Financial Statements

which a portion of our new pipeline will traverse. These legal disputes have impeded the construction of our new pipeline. For additional information regarding our legal disputes with CNX, see Item 3. Legal Proceedings CNX Surface Dispute.

In the event we are unable to complete the construction of our alternate pipeline to connect to the Jewell Ridge Pipeline by April 30, 2007 as a result of our legal disputes with CNX or other factors, we will be required to find an alternative to get our gas from the Pond Creek field to market, including constructing an alternate pipeline at a cost in excess of $12 million; changing the planned route of our new pipeline we are currently constructing, which could add more than $5 million to the cost of construction of our new pipeline; paying CNX an access fee for any gas transported across the PMC property at a rate up to or more than 3.5% of the gross proceeds from the sale of such gas; or seeking 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 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

Table of Contents

Index to Financial Statements

issuances of common stock. Our future contractual commitments from January 1, 2007 through December 31, 2012 total $92.9 million and include debt service, operating lease obligations, firm transportation obligations and other obligations, collectively aggregating approximately $9.2 million during 2007, $20.9 million during 2008 to 2010, and $62.8 in 2011 when our existing credit facility matures. We also require capital to fund our drilling budget, which is expected to be $69 million for 2007. 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, 2006 would result in an additional $600,000 of interest expense.

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

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

Our credit facility subjects us to a number of covenants that impose restrictions on us, including our ability to incur indebtedness and liens, make loans and investments, sell assets, engage in mergers, consolidations and acquisitions, enter into transactions with affiliates, or pay dividends. 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 annual report.

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.

22

Table of Contents

Index to Financial Statements

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 December 31, 2006 and will be completed by June 30, 2007. Upon a redetermination, we could be required to repay a portion of our bank debt. We may not have sufficient funds to make such repayments, which could result in a default under the terms of the credit facility and an acceleration of our indebtedness. At December 31, 2006, we have $60 million outstanding under a borrowing base of $150 million.

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

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

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

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

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

We may face unanticipated water disposal costs.

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

- we cannot obtain future permits from applicable regulatory agencies;
- water of lesser quality is produced;
- our wells produce excess water; or
- new laws and regulations require water to be disposed of in a different manner.

Our 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, 2006, we had identified and scheduled 633 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,

23

Table of Contents

Index to Financial Statements

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 employment agreements or non-competition agreements with any of our key employees, other than J. Darby Seré, our President and Chief Executive Officer, 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

Table of Contents

Index to Financial Statements

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. In some cases a consent to stimulate the coal seam may be required from a coal owner or operator before a permit is issued. 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 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

Table of Contents

Index to Financial Statements

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, 2006, we recognized total gains on our outstanding hedges of approximately $17.9 million (consisting of a $1.1 million realized gain and a $16.8 million unrealized gain). Based upon the hedges we had in place at December 31, 2006, hypothetical 10% and 25% increases in natural gas prices would increase pre-tax loss of approximately $2.8 million and $7.2 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, 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.

Item 1B. ***Unresolved Staff Comments***

None.

Item 2. ***Properties***

Estimated Proved Reserves

The following table sets forth certain information with respect to our estimated proved reserves by field as of December 31, 2006. Reserve volumes and values were determined under the method prescribed by the SEC which requires the application of period-end prices and current costs held constant throughout the projected reserve life. The reserve information as of December 31, 2006 is based on estimates made in a reserve report prepared by DeGolyer and MacNaughton, independent petroleum engineers.

	Estimated Proved Reserves				
Field	**Proved Developed Producing (MMcf)**	**Proved Developed Non-Producing (MMcf)**	**Proved Undeveloped (MMcf)**	**Total Proved (MMcf)**	**PV-10 (In thousands)**
Central Appalachia:					
Pond Creek field	89,045		40,962	130,007	$ 210,943
Alabama:					
Gurnee field	119,683	31,685	41,782	193,150	305,780
White Oak Creek field	2,424	81		2,505	8,910
Total	211,152	31,766	82,744	325,662	$ 525,633

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

Table of Contents

Index to Financial Statements

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 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 Financial 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 annual report 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, 2006 used to estimate proved reserves and future net revenue was $5.71 per MMBtu and was calculated using the Henry Hub cash price at December 31, 2006, of $5.63 per MMBtu of gas, adjusted for our price differentials but excluding the effects of hedging.

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,		
	2006	**2005**	**2004**
Gas:			
Net sales volume (Bcf)	6.2	4.6	3.2
Average natural gas sales price ($ per Mcf)	$ 7.22	$ 9.06	$ 6.12
Average natural gas sales price ($ per Mcf) realized(1)	$ 7.40	$ 7.43	$ 5.87
Total production expenses ($ per Mcf)	$ 2.75	$ 2.81	$ 2.36
Expenses: ($ per Mcf)			
Lease operations expenses	$ 1.86	$ 1.89	$ 1.60
Compression and transportation expenses	$ 0.72	$ 0.72	$ 0.61
Production taxes	$ 0.17	$ 0.20	$ 0.15
Depreciation, depletion & amortization	$ 1.26	$ 1.06	$ 0.84
Research and development	$ 0.02	$ 0.13	$ 0.09
General and administrative	$ 1.09	$ 0.70	$ 0.79

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

Table of Contents

Index to Financial Statements

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, 2006. 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**
Central Appalachian Basin	203	203	13,160	13,160	42,350	42,021
Cahaba Basin	194	194	13,666	13,666	29,416	29,166
North Central Louisiana(2)	16	16			122,612	119,244
British Columbia(2)	6	3			36,575	18,288
Piceance Basin					17,000	16,949
Other (United States)					35,603	27,747
Total	419	416	26,826	26,826	283,556	253,415

(1) Excludes 21 gross and 20.5 net wells pending completion at December 31, 2006.
(2) The productive wells listed in the above schedule for North Central Louisiana and British Columbia are exploratory productive wells that were drilled on undeveloped acreage that meet the SEC definition of a productive well.

Our material undeveloped leases are in the Cahaba Basin and Central Appalachian Basin, which includes our Gurnee field and Pond Creek field, respectively. Generally, the undeveloped acreage related to our Pond Creek field will expire in 2007 and 2008; however, the term of this undeveloped acreage can be extended by drilling and production operations. As to the Gurnee field, we have fulfilled drilling commitments on our largest lease that gives us the ability to postpone further drilling until 2009. Otherwise, the remaining acreage in the Gurnee Field either has expirations that occur from 2008 through 2011 or the leases can be extended by drilling and production operations.

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.

	Exploratory			Development		
Well Activity (Gross) United States	**Productive**	**Dry**	**Total**	**Productive**	**Dry**	**Total**
Year ended December 31, 2006	2		2	102		102
Year ended December 31, 2005	4	3	7	93		93
Year ended December 31, 2004	10	1	11	85		85

	Exploratory			Development		
Well Activity (Gross) Canada	**Productive**	**Dry**	**Total**	**Productive**	**Dry**	**Total**
Year ended December 31, 2006	3		3			
Year ended December 31, 2005	2		2			

Table of Contents

Index to Financial Statements

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.

	Exploratory			Development		
Well Activity (Net) United States	**Productive**	**Dry**	**Total**	**Productive**	**Dry**	**Total**
Year ended December 31, 2006	2.0		2.0	102.0		102.0
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

	Exploratory			Development		
Well Activity (Net) Canada	**Productive**	**Dry**	**Total**	**Productive**	**Dry**	**Total**
Year ended December 31, 2006	1.5		1.5			
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.

Item 3. *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 the White Oak Creek field in Alabama. We had previously entered into an agreement to sell our interests in the field 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 own in the field. The trial court rendered judgment in our favor, and El Paso appealed the decision of the trial court. The appellate court reversed the trial court s decision in favor of El Paso and remanded the case to the trial court to determine whether El Paso is entitled to specific performance and damages (lost royalties). To date, El Paso has not paid us the allocated purchase price for the overriding royalties of approximately $10.5 million. We have received royalty payments from the disputed overriding royalty interests of approximately $8.5 million since April 2004. We have filed a petition for a rehearing with the appellate court and are considering additional legal options including further appeals, if necessary.

CNX Surface Use Dispute

We have substantially completed the construction of a 12-mile pipeline, a portion of which traverses a right-of-way granted by PMC, which will connect with and transport our gas to the Jewell Ridge Pipeline. CNX,

29

Table of Contents

Index to Financial Statements

the lessor of certain minerals underlying the PMC property, has claimed that it has the exclusive right to transport gas across the PMC property and that our right-of-way is invalid. We and PMC filed a complaint in the Circuit Court of Buchanan County, Virginia on May 26, 2006 against CNX seeking a temporary and permanent injunction, as well as a declaration of our rights under the right-of-way agreement that we entered into with PMC, the surface owner. 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 have completed construction of the portion of the pipeline crossing the disputed right-of-way. In light of facts developed in discovery, we and PMC have filed a motion to amend our complaint to assert claims for damages in the amount of $350,000 associated with the delay and attorney s fees caused by the actions of CNX and additional grounds for relief. Trial dates previously set for April 17 and 18, 2007 to determine the rights of the parties as to the use of the PMC property and who has the right to transport gas across the PMC property have been cancelled and have not yet been rescheduled.

We believe that our right-of-way agreement across the PMC property is valid and enforceable and that we will prevail in the lawsuit. We expect our pipeline interconnect to the Jewell Ridge Pipeline to be completed and fully operational by April 1, 2007, in advance of the April 30, 2007 date on which our existing gathering and transportation agreement with a CNX affiliate is terminable by either party. However, in the event we are unsuccessful in obtaining a favorable judgment in this lawsuit, we may be required to construct an alternate pipeline at a cost in excess of $12 million, construct an alternate pipeline route around the PMC property at a cost of more than $5 million, pay CNX an access fee for any gas transported across the PMC property at a rate up to or more than 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.

On January 19, 2007, CNX obtained a temporary injunction against our construction of the same 12-mile pipeline across 1,450 feet of a 32-acre tract in Tazewell County, Virginia. The tract of land in dispute has been owned by a large number of extended family members, from whom we have obtained approximately 81% control of the tract, either through purchases of undivided surface interests in the property or by entering into surface use and right-of-way easement agreements. During our pipeline construction process, CNX purchased a minority undivided surface interest in the property and filed a lawsuit seeking to enjoin the construction of our pipeline across the tract. On February 16, 2007, the Virginia Supreme Court vacated the temporary injunction, which allowed us to complete construction of our pipeline across the 32-acre tract. Both we and CNX have filed complaints to partition the 32-acre tract, and we believe that we will obtain full ownership of the portion of the property that our pipeline traverses. In the event we receive an unfavorable decision in the partitioning of the property in question, we may be required to construct an alternate route for our pipeline around this 32-acre tract at a cost of up to $1 million.

In the event we are required to seek any of the above alternatives to our current plans for our 12-mile pipeline and assuming such alternatives are available, we may be unable to deliver our gas from the Pond Creek field to market for an extended period of time.

CNX Antitrust Action

We filed a complaint against CNX and Island Creek Coal Company, an affiliate of CNX (Island Creek), in the Circuit Court of Tazewell County, Virginia on February 14, 2007, seeking damages arising from alleged violations of the Virginia Antitrust Act, tortious interference with contractual relations with third parties, and statutory and common law conspiracy. The suit seeks $561 million for compensatory and consequential damages for alleged violations of the Virginia Antitrust Act, including alleged anticompetitive efforts of CNX to dominate and maintain its control over the market for the production and transportation of coalbed methane gas from the Oakwood Field in Buchanan County, Virginia and for CNX s alleged efforts to conspire and act in concert with

Table of Contents

Index to Financial Statements

Island Creek and others to dominate and maintain control over the market for the production and transportation of coalbed methane gas from the Oakwood Field in violation of the Virginia Antitrust Act and Virginia statutory and common law. The suit also alleges CNX s intentional interference with our existing and prospective third-party business relationships in efforts to harm us and improve CNX s position and corporate and financial interests. We seek to have any damages awarded for alleged violations of the Virginia Antitrust Act tripled under Virginia statutes permitting a court to award treble damages, as well as injunctive relief to prevent CNX and other parties from continuing these alleged anticompetitive activities.

Item 4. ***Submission of Matters to a Vote of Security Holders***

None.

Table of Contents

Index to Financial Statements

PART II

Item 5. ***Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.***

Common Stock

Our common stock was listed on the NASDAQ Global Market on July 28, 2006 under the symbol GMET . The table below shows the high and low closing prices of our common stock for the periods indicated.

	High	Low
Fiscal Year 2006:		
Quarter ended September 30, 2006	$ 11.71	$ 9.40
Quarter ended December 31, 2006	$ 11.25	$ 8.66

On March 1, 2007, the closing price of our common stock on the NASDAQ was $8.19 per share, and there were approximately 38.7 million shares of our common stock outstanding, held by approximately 1,500 holders of record.

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 therefore after payment of dividends required to be paid on shares of preferred stock, if any. We have not declared or paid any dividends on our shares of common stock and do not currently anticipate paying any dividends on our shares of common stock in the future. Currently our plan is to retain any future earnings for use in the operations and expansion of our natural gas exploration business. Our credit facilities currently prohibit us from paying any cash dividends on our common 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.

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. We used the net proceeds from our private placement of common stock 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 to reduce outstanding borrowings under our bank credit facility and for general corporate purposes.

Table of Contents

Index to Financial Statements

On August 2, 2006, we sold 5,750,000 shares of common stock in an initial public offering. We received net proceeds from the offering of approximately $52.6 million, after deducting estimated offering expenses and underwriting discounts and commissions, and used the net proceeds from the offering to reduce outstanding borrowings under our bank credit facility.

No equity securities of the Company were repurchased during the fiscal year ended December 31, 2006. We do not have a publicly announced program to repurchase shares of our common stock.

Performance Graph

The following performance graph and related information shall not be deemed soliciting material or to be filed with the Securities and Exchange Commission, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that we specifically incorporate the performance graph by reference into such filing.

The following graph compares the cumulative total stockholder return on our common stock from July 28, 2006, the date our common stock was initially listed on the Nasdaq Global Market, through December 31, 2006 and compares it with the cumulative total return on the S&P 500 Index and the S&P Oil and Gas Exploration and Production Index. The comparison assumes $100 was invested on July 28, 2006 and assumes reinvestment of dividends, if any. The comparisons in this table are required by the SEC and are not intended to forecast or be indicative of possible future performance of our stock.

Table of Contents

Index to Financial Statements

Item 6. ***Selected Financial Data***

The following table shows our selected historical consolidated financial and operating data as of and for each of the five years ended December 31, 2006. The selected historical consolidated financial and operating data for the three years ended December 31, 2006 are derived from our audited financial statements included herein. The selected historical consolidated financial and operating data for the two years ended December 31, 2003 was derived from our audited financial statements which are not included herein. The table reflects a four-for one common stock split in 2006 and prior periods have been adjusted for the stock split. 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 annual report where there is additional disclosure regarding the information in the following table. Our historical results are not necessarily indicative of the results that may be expected in future periods.

	Year Ended December 31,				
	2006	**2005**	**2004**	**2003**	**2002**
STATEMENT OF OPERATIONS :					
Total revenues	$ 58,137	$ 41,980	$ 20,924	$ 12,049	$ 7,008
Impairment of other equipment and other non-current assets				8	108
Realized (gain) losses on derivative contracts	(1,118)	7,473	815	44	
Unrealized (gains) losses from the change in market value of open derivative contracts	(16,877)	12,059	(542)	102	
Total operating expenses	26,831	41,149	13,272	7,123	5,554
Income (loss) from operations	31,305	831	7,652	4,926	1,454
Interest expense, net of amounts capitalized	(3,130)	(3,895)	(986)	(232)	(186)
Income (loss) before income taxes, minority interest, and cumulative effect of change in accounting principle, net of income tax	28,199	(3,008)	6,732	4,782	1,380
Income tax expense (benefit)	10,880	(993)	2,312	1,651	639
Net income (loss) before minority interest and cumulative effect of change in accounting principle, net of income tax	17,319	(2,015)	4,420	3,131	741
Minority interest	(23)	(442)	584	571	138
Net income (loss) before cumulative effect of change in accounting principle, net of income tax	17,296	(1,573)	3,836	2,560	603
Cumulative effect of change in accounting principle, net of income tax				19	
Net income (loss)	$ 17,296	$ (1,573)	$ 3,836	$ 2,541	$ 603
Net income (loss) per common share:					
Basic	$ 0.49	$ (0.06)	$ 0.17	$ 0.20	$ 0.08
Diluted	$ 0.48	$ (0.06)	$ 0.17	$ 0.20	$ 0.08
BALANCE SHEET DATA (at period end):					
Working (deficit) capital	$ (1,625)	$ (7,368)	$ (1,251)	$ 5,133	$ 3,940
Total assets	$ 335,195	$ 247,909	$ 142,090	$ 81,505	$ 42,261
Long-term debt	$ 60,832	$ 99,926	$ 51,513	$ 10,102	$ 6,665
Stockholders equity	$ 210,007	$ 95,422	$ 65,692	$ 52,754	$ 22,912
Cash flow Data:					
Net cash provided by operating activities	$ 21,472	$ 12,433	$ 10,580	$ 10,801	$ 4,603
Net cash used in investing activities	$ (78,669)	$ (59,661)	$ (66,193)	$ (36,341)	$ (12,773)
Net cash provided by financing activities	$ 58,086	$ 44,906	$ 50,192	$ 30,534	$ 5,372
Capital expenditures	$ 79,061	$ 59,817	$ 86,189	$ 36,069	$ 12,770
OTHER DATA:					
Net sales volume (Bcf)	6.2	4.6	3.2	2.5	2.1
Average natural gas sales price ($ per Mcf)	$ 7.22	$ 9.06	$ 6.12	$ 4.71	$ 3.16
Average natural gas sales price ($ per Mcf) realized(1)	$ 7.40	$ 7.43	$ 5.87	$ 4.69	$ 3.16
Total production expenses ($ per Mcf)	$ 2.75	$ 2.81	$ 2.36	$ 1.23	$ 0.72
Depreciation, depletion and amortization	$ 1.26	$ 1.06	$ 0.84	$ 0.85	$ 0.88
Estimated proved reserves (Bcf)(2)	325.7	262.5	209.9	103.9	35.5
Standardized measure of discounted future net cash flows ($ millions)	$ 359.5	$ 632.7	$ 349.8	$ 172.5	$ 45.4
Non-GAAP Measures:(3)					
PV-10 ($ millions)	$ 525.6	$ 880.2	$ 481.8	$ 236.9	$ 64.4

(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.

Table of Contents

Index to Financial Statements

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,				
	2006	2005	2004	2003	2002
			(In thousands)		
Future cash inflows	$ 1,858,104	$ 2,536,279	$ 1,302,830	$ 599,501	$ 163,986
Less: Future production costs	501,955	463,416	290,425	125,765	48,771
Less: Future development costs	101,777	76,297	38,242	23,832	4,676
Future net cash flows	1,254,371	1,996,566	974,163	449,904	110,539
Less: 10% discount factor	728,739	1,116,413	(492,339)	(213,018)	(46,095)
PV-10	$ 525,632	$ 880,153	481,824	236,886	64,444
Less: Undiscounted income taxes	(410,391)	(579,689)	(274,975)	(125,858)	(32,101)
Plus: 10% discount factor	244,245	332,201	142,906	61,520	13,084
Discounted income taxes	(166,146)	(247,488)	(132,069)	(64,338)	(19,017)
Standardized measure of discounted future net cash flows	$ 359,486	$ 632,665	$ 349,755	$ 172,548	$ 45,427

Table of Contents

Index to Financial Statements

Item 7. ***Management s Discussion and Analysis of Financial Condition and Results of Operations***

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the financial statements and the related notes and other information included elsewhere in this report.

Overview

We are an independent natural gas producer involved in the exploration, development, and production of coalbed methane. Our principal operations and producing properties are located in the Cahaba Basin in Alabama and the central Appalachian Basin in West Virginia and Virginia. As of December 31, 2006, we control a total of approximately 280,000 net acres of coalbed methane and oil and gas development rights, primarily in Alabama, West Virginia, Virginia, Louisiana, Colorado, and British Columbia. We operate in two segments, natural gas exploration, development and production, almost exclusively within the continental United States and British Columbia and gas marketing in the United States.

We have been very active in North America for over 20 years as an operator of CBM fields owned by us, as a contract operator of 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 six 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 central 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.

The variable interest entity consolidated for the period August 1, 2006 through December 31, 2006 (see Note 4 of the consolidated financial statements) added a gas marketing activity that resulted in a second reportable segment to our core business of natural gas exploration, development and production.

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. We used the net proceeds from our private placement of common stock 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 to reduce outstanding borrowings under our bank credit facility and for general corporate purposes.

On August 2, 2006, we sold 5,750,000 shares of common stock in an initial public offering. We received net proceeds from the offering of approximately $52.6 million, after deducting estimated offering expenses and underwriting discounts and commissions, and used the net proceeds from the offering to reduce outstanding borrowings under our bank credit facility.

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 is critical to our long-term success.

For the year ended December 31, 2006, gas sales quantities increased by 1,635 MMcf from the comparable period in 2005 to 6,228 MMcf. The increase in sales was related to the continued development of our Cahaba and Pond Creek fields. Average gas sales prices for the year ended December 31, 2006 decreased by $1.84 per Mcf from the prior year period to $7.22 per Mcf.

Table of Contents

Index to Financial Statements

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 $16.9 million for the year ended December 31, 2006 compared to unrealized losses of $12.1 million for year ended December 31, 2005. For the year ended December 31, 2006 we had realized gains in the amount of $1.1 million compared to realized losses of $7.5 million for the year ended December 31, 2005.

We believe that our cash flow from operations and other financial resources such as borrowings under our credit facility, proceeds from our initial public equity offering that closed on August 2, 2006, and proceeds from future equity offerings will provide us with the ability to develop our existing properties and finance our current exploration on unevaluated properties.

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 annual report. 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.

Table of Contents

Index to Financial Statements

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; however, as allowed by the Securities and Exchange Commission guidelines, significant changes in gas prices subsequent to quarter end are used in the ceiling test. 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 and 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

Table of Contents

Index to Financial Statements

production. Currently, we use collars and fixed-price swaps as our mechanism for hedging commodity prices. We account for our derivative instruments under the provisions of SFAS No. 133 *Accounting for Derivative Instruments and Hedging Activities*, as amended. 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. We record the fair value of our derivative instruments on our balance sheet as either an asset or liability. Our estimates of fair value are determined by obtaining independent market quotes from an independent third party and comparing to estimates from our counterparties. The fair values determined by the third party and counterparties are based, in part, on estimates and judgments. 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. If commodity prices increase, we may recognize losses in future periods similar to 2005; however, for the year ended December 31, 2006 prices decreased, and we recognized a total gain on derivative contracts in the amount of $18 million, consisting of a $1.1 million realized gain and a $16.9 million unrealized gain.

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

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

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

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

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. The application of SFAS 123R requires the use of a model similar to the Black Scholes model to measure the estimated fair value of the options and as a result various assumptions must be made by management that require judgment and the assumptions could be highly uncertain. The significant assumptions include the expected term, volatility, interest rate and expected dividends. 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.

Table of Contents

Index to Financial Statements

Natural Gas Production Producing Fields Operations Summary

The table below presents information on gas revenues, sales volumes, production expenses and per Mcf data for the years ended December 31, 2006, 2005 and 2004. This table should be read with the discussion of the results of operations for the periods presented below.

	Year Ended December 31,		
	2006	2005	2004
Gas sales	$ 44,952	$ 41,604	$ 19,522
Lease operating expenses	$ 11,579	$ 8,687	$ 5,092
Compression and transportation expenses	4,499	3,332	1,951
Production taxes	1,037	914	473
Total production expenses	$ 17,115	$ 12,933	$ 7,516
Net sales volumes (MMcf)	6,228	4,594	3,187
Pond Creek field (MMcf)	3,844	2,923	1,631
Gurnee field (MMcf)	1,950	1,182	435
Per Mcf data ($/Mcf):			
Average natural gas sales price	$ 7.22	$ 9.06	$ 6.12
Average natural gas sales price realized(1)	$ 7.40	$ 7.43	$ 5.87
Lease operating expenses	$ 1.86	$ 1.89	$ 1.60
Pond Creek field	$ 1.54	$ 1.52	$ 2.82
Gurnee field	$ 2.90	$ 3.55	$ 3.56
Compression and transportation expenses	$ 0.72	$ 0.72	$ 0.61
Pond Creek field	$ 0.98	$ 0.95	$ 0.89
Gurnee field	$ 0.38	$ 0.43	$ 0.55
Production taxes	$ 0.17	$ 0.20	$ 0.15
Pond Creek field	$ 0.02	$ 0.02	$
Gurnee field	$ 0.41	$ 0.53	$ 0.33
Total production expenses	$ 2.75	$ 2.81	$ 2.36
Pond Creek field	$ 2.54	$ 2.50	$ 2.82
Gurnee field	$ 3.68	$ 4.52	$ 4.44
Depreciation, depletion and amortization	$ 1.26	$ 1.06	$ 0.84

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

Table of Contents

Index to Financial Statements

Results of Operations

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

The following are selected items are derived from our unaudited consolidating statement of operations, which are not included herein, and their percentage changes from the comparable period are presented below.

	Year Ended December 31, 2006	2005	Change
	(In thousands)		
Gas sales	$ 44,952	$ 41,604	8%
Operating fees and other	141	376	(63)%
Total revenues	45,093	41,980	7%
Lease operating expenses	11,579	8,687	33%
Compression and transportation expenses	4,499	3,332	35%
Production taxes	1,037	914	14%
Depreciation, depletion and amortization	7,876	4,867	62%
Research and development	129	609	(79)%
General and administrative	6,553	3,208	104%
Realized (gains) losses on derivative contracts	(1,118)	7,473	NM
Unrealized (gains) losses from the change in market value of open derivative contracts	(16,877)	12,059	NM
Total operating expenses	15,914	41,149	NM
Income from natural gas production	$ 29,179	$ 831	NM

NM-Not Meaningful

Gas sales. Gas sales increased by $3.3 million, or 8%, to $44.9 million compared to the prior year. The increase in gas sales was a result of increased production, partially offset by lower average gas prices. Production increased 36% while average gas prices, excluding hedging transactions, decreased 20%. The $3.3 million increase in gas sales consisted of a $14.8 million increase in production and an $11.5 million decrease in average prices. The increase in production was principally attributable to our Cahaba and Pond Creek development activities.

Lease operating expenses. Lease operating expenses increased by $2.9 million, or 33% to $11.6 million. The $2.9 million increase in lease operating expenses consisted of $3.1 million increase in production and $0.2 million decrease in costs. The decrease in costs is related to a decrease in well service activities from the prior year period.

Compression and transportation expenses. Compression and transportation expenses increased by $1.2 million, or 35% to $4.5 million. The $1.2 million increase in compression and transportation expenses was driven entirely by the increase in production.

Production taxes. Production taxes increased by $0.123 million, or 14%, to $1.0 million. The production taxes increase of $0.123 million was primarily due to increased production, partially offset by lower average gas prices.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $3.0 million, or 62%, to $7.9 million. The depreciation, depletion and amortization increase of $4.5 million consisted of a $3.3 million increase in depletion rate and a $1.2 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

Table of Contents

Index to Financial Statements

accounting adjustment related to the acquisition of the minority interest stock in a subsidiary on April 2005 and increased future development costs. Future development costs increased due to increased proved undeveloped wells and higher costs of drilling.

General and administrative. General and administrative expenses increased by $3.3 million, or 104%, to $6.5 million. The increase in general and administrative expenses was a result of increases in employee expenses (22%), professional services (466%), director and investor relations expenses (100%), insurance expense (176%) and office expenses and business taxes (56%). This increase was partially offset by increased capitalized general and administrative expenses recoveries (17%) related to field, operating recoveries and capitalized general and administrative expenses. The largest dollar increase was in employee expenses and professional services that resulted from the increased audit, Sarbanes Oxley, tax and legal services. The increase in general and administrative expenses was a result of expanding the overhead structure to support our growth and increased costs of being a public company.

Realized (gains) losses on derivative contracts. Realized (gains) losses on derivative contracts increased by $8.6 million to $1.1 million compared to a loss of $7.5 million in the prior 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 (gains) losses from the change in market value of open derivative contracts. Unrealized (gains) losses from the change in market value of open derivative contracts generated a $16.9 million gain as compared to a $12.1 million loss in the prior period. 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 $16.9 million gain was a result of decreased future commodity gas prices.

Results of Operations Marketing Natural Gas

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

The variable interest entity consolidation during the year (see Note 4 of the consolidated financial statements) added a gas marketing activity that added a second reportable segment to our core business of natural gas exploration, development and production.

The following are selected items derived from our consolidating statement of operations which are not included herein and their percentage changes from the comparable period are presented below.

	Year Ended December 31, 2006	2005
	(In thousands)	
Gas marketing	$ 13,044	
Purchased gas	12,899	
Gross Margin	145	
General and administrative expenses	254	
Loss from marketing natural gas (after inter-segment profit elimination of $131,996)	$ (109)	

Table of Contents

Index to Financial Statements

Results of Operations   Corporate

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

Interest expense (net of amounts capitalized). Interest expense (net of amounts capitalized) decreased by $0.765 million, or 20%, to $3.1 million. The decrease was primarily due to lower outstanding bank balances and was partially offset by higher interest rates. Capitalized interest totaled $1.0 million and $0.7 million for the years ended December 31, 2006 and 2005, respectively.

Income tax expense (benefit). Income tax expense (benefit) resulted in an expense of $10.9 million in the year ended December 31, 2006 compared to a benefit of $0.993 million in the prior period. The increase in income tax expense for the year was due to (1) pretax income versus a pretax loss in the prior period and (2) an increase in the effective tax rate for the year to 38% from 33% in the 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.

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 sale of certain of our White Oak Creek properties (the   White Oak Creek Sale   ) and the acquisition of our Pond Creek properties (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 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 (benefit) provision	(993)	2,312	(143)%
Net (loss) income 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.

Table of Contents

Index to Financial Statements

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 million from $0.61 million. 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 million from $0.78 million 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 swaps 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 counterparties during the year. The realized losses are recorded in total operating expenses in the Consolidated Statement of Operations and Comprehensive Income.

Table of Contents

Index to Financial Statements

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 ended 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.

Income tax expense (benefit). 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.

Liquidity and Capital Resources

Cash Flows and Liquidity

Cash flow from operations for the year ended December 31, 2006 and 2005 were $21.5 million and $12.4 million, respectively. Cash flow from operations for the year ended December 31, 2006 of $21.5 million combined together with net proceeds from the sale of common stock of $79 million and proceeds from the collection of notes receivable of $17.2 million were sufficient to fund our cash basis capital expenditures of $79.1 million and the repayment of our revolving credit facility and other debt of $39 million.

As of December 31, 2006 and 2005, we had a working capital deficit of approximately $1.7 million and $7.4 million, respectively. The decrease in the working capital deficit was primarily a result of the mark to market of our derivatives position resulting in a net asset position at year end 2006 versus a liability position at year end 2005. At December 31, 2006, we had adequate cash flows from operating activities and 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 2007 will be approximately $69 million with approximately 83% allocated to development projects, 6% to exploration projects, and 11% to leasehold, representing a decrease of approximately $12.6 million under our actual 2006 capital expenditures. The 2007 estimated capital expenditures are primarily attributable to continued development expenditures at Pond Creek and Cahaba. As of December 31, 2006 we have approximately $90 million of available borrowing capacity under our revolving credit facility. The following table is a summary of the Company s capital expenditures on an accrual basis by category:

	Year Ended December 31,		
	2006	2005	2004
		(In thousands)	
Capital expenditures:			
Leasehold acquisition	$ 8,975	$ 2,012	$ 1,571
Exploration	7,626	8,620	6,759
Development	62,211	46,397	49,023
Acquisitions			27,046
Other items (primarily capitalized overhead and interest)	2,781	2,173	1,790
Total capital expenditures	$ 81,593	$ 59,202	$ 86,189

Table of Contents

Index to Financial Statements

Capital expenditures for the year ended December 31, 2006 were higher than 2005 due to increased development activities in the Pond Creek and Gurnee fields. Our capital expenditures for the year ended December 31, 2005 were approximately equal to the comparable 2004 period, exclusive of the Pond Creek Acquisition. Development expenditures in 2005 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.

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 proceeds from our private and public offerings to fund our 2007 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 natural 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 of more than two years. We generally limit the amount of these hedges during periods of relatively high financial leverage 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 $3.00 per MMBtu. 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 of 2005 in response to Hurricanes Katrina and Rita, resulted in significant unrealized losses. More recently, the decrease in gas prices has created significant unrealized gains. In 2006, commodity prices decreased from 2005 and this resulted in significant realized and unrealized gains. The unrealized gains and losses have no impact on cash flows.

We believe that the use of derivative instruments does not expose us to material risk unless we are over hedged. 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 the use of these instruments will not have a material adverse effect on our financial position or liquidity.

We account for our derivative contracts as accounting hedges using mark-to-market accounting under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*. During the year ended

Table of Contents

Index to Financial Statements

December 31, 2006, natural gas prices increased and we recognized a total gain on derivative contracts in the amount of $18 million which consisted of $1.1 million realized gain and $16.9 million unrealized gain.

As of December 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. 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. We have not entered into any new gas derivative contracts subsequent to December 31, 2006.

At December 31, 2006 and at December 31, 2005, the fair values of open derivative contracts were assets and liabilities of approximately $5.3 million and $11.5 million, respectively.

				Collars	
Instrument Type	**Production Period**	**Volumes (MMBtu)**	**Swap Price**	**Weighted Average Floor Prices ($/MMBtu)**	**Weighted Average Cap Prices ($/MMBtu)**
Collars (3 way)	Jan-Mar 2007	900,000		$ 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
Traditional Collars	Summer 2007	856,000		$ 7.50	$ 9.75
Traditional Collars	Winter 2007/2008	608,000		$ 8.25	$ 11.25
Swaps	Jan-Mar 2007	360,000	$ 7.75		

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

	Incremental increase (decrease) in pre-tax gain assuming a hypothetical price increase and decrease of natural gas prices(1)	
	10%	**25%**
	(in thousands)	
Price increase	$ (2,822)	$ (7,202)
Price decrease	$ 2,651	$ 6,521

(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.

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 our 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. Our 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

Table of Contents

Index to Financial Statements

(LIBOR) plus a margin of 1.00% to 2.00%, based on borrowing base usage. Borrowings under our credit agreement are secured by first priority liens on substantially all of our assets including equity interests in our subsidiaries. All outstanding borrowings under our credit agreement become due and payable on January 6, 2011.

We are subject to financial covenants requiring maintenance of a minimum current ratio and a minimum interest coverage ratio. Our ratio of consolidated current assets (defined to include amounts available under our 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 same 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. As of December 31, 2006, we are in compliance with all of the covenants in the credit agreement.

In addition, the borrowing base under our credit facility is redetermined semi-annually and may also be re-determined once each fiscal year for any reason upon request by lenders representing 66.66% of the total commitment under our credit facility. Re-determinations are based upon a number of factors, including commodity prices and reserve levels. 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. The next scheduled redetermination is to occur as of December 31, 2006 and will be completed by June 30, 2007.

At December 31, 2006, $60 million was outstanding under our credit facility. Interest on the borrowings averaged 6.41% per annum. Borrowing availability at December 31, 2006 was $90 million. 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 December 31, 2006, a 1% change in market interest rates would have increased interest expense and negatively impacted our annual cash flows by approximately $600,000.

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

Table of Contents

Index to Financial Statements

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, 2006:

	Beginning January 1, 2007(1)				
	One Year	2-4 Years	5-6 Years	More than 6 Years	Total
			(In thousands)		
Long-term debt and other obligations(2)	$ 94	$ 336	$ 60,496	$	$ 60,926
Interest expense on bank credit facility(3)	4,164	12,492	63		16,719
Operating lease obligations	1,532	3,970	1,650	239	7,391
Asset retirement obligations	73			2,481	2,554
Firm transportation contracts	1,213	3,555	594		5,362
Other operating commitments	2,092	600			2,692
Total commitments	$ 9,168	$ 20,953	$ 62,803	$ 2,720	$ 95,644

(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 June 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 5.44% plus the current 1.50% margin for a total interest rate of 6.94%.

Off-Balance Sheet Arrangements

In December 2003, the Financial Accounting Standards Board (the FASB) issued Interpretation No. 46 (revised), *Consolidation of Variable Interest Entities* (FIN 46(R)), which requires variable interest entities to be consolidated by their primary beneficiaries. A primary beneficiary is the party that absorbs a majority of the entity s expected losses or receives a majority of the entity s expected residual returns, or both, as a result of ownership, contractual or other financial interests in the entity.

We market substantially all of our gas through Shamrock Energy LLC, which became a wholly owned subsidiary on January 1, 2007, under a natural gas purchase agreement. The purchase agreement calls for Shamrock to purchase and us to sell gas produced from all of our major properties. In addition, 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 sold, less a fee for Shamrock s services ranging from $0.03 to $0.045 per MMBtu purchased.

On June 14, 2006, we entered into an option agreement with Jon M. Gipson, the president of Shamrock, pursuant to which we had the right to acquire all of the outstanding equity interests and assets of Shamrock. 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, the termination date of the Shamrock purchase option (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 entered into during the option period that require such guaranties, up to an aggregate of $1,500,000, and (iv) to advance Shamrock up to an additional $50,000 to Shamrock as may be required to cover certain expenses of Shamrock prior to January 31, 2007.

We exercised the Shamrock purchase option on January 1, 2007, at which time we provided Mr. Gipson an at-will employment position with us. Also, on March 9, 2007, we caused Shamrock to distribute to Mr. Gipson

Table of Contents

Index to Financial Statements

approximately $22,500, which equals 50% of the net profits generated by Shamrock from August 1, 2006 through January 1, 2007. This amount was accrued at December 31, 2006 as a dividend payable to Mr. Gipson. No additional consideration was paid as a result of our exercise of this option.

In accordance with FIN 46(R), we consolidated Shamrock into our financial statements, effective August 1, 2006. We did not have any voting interest in Shamrock prior to January 1, 2007 and as a result the consolidation of Shamrock did not have a material impact on our results of operations for year ended December 31, 2006. Other than the Shamrock customers that we have provided guarantees to on behalf of Shamrock, the remainder of Shamrock s customers have no recourse against us. Our potential losses were limited to the current advance of $90,000 and the amounts outstanding under the existing guarantees ($1,160,000) which have not been recorded as a liability as of December 31, 2006. As of December 31, 2006, $3,387,118 of assets and $3,387,118 of liabilities have been included in our audited consolidated balance sheet as a result of applying FIN 46(R) to Shamrock, a variable interest entity. Over 99% of the assets and liabilities are current.

Recent Accounting Pronouncements

In July 2006, the FASB issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes. The interpretation prescribes a two-step process in the recognition and measurement of a tax position taken or expected to be taken in a tax return. The first step is to determine if it is more likely than not that a tax position will be sustained upon examination by taxing authorities. If this threshold is met, the second step is to measure the tax position on the balance sheet by using the largest amount of benefit that is greater than 50% likely of being realized upon ultimate settlement. FIN 48 also requires additional disclosures. FIN 48 is effective prospectively for fiscal years beginning after December 15, 2006. Based on our initial assessment, we do not expect a material impact on our consolidated financial position or results of operations in the first quarter of 2007.

In September 2006, the FASB issued FASB No. 157, *Fair Value Measurements* (FASB 157). FASB 157 establishes a single authoritative definition of fair value sets out a framework for measuring fair value and requires additional disclosures about fair value measurements. FASB 157 applies only to fair value measurements that are already required or permitted by other accounting standards. FASB 157 is effective for fiscal years beginning after November 15, 2007. The Company will adopt this Statement in fiscal 2007 and adoption is not expected to have a material impact on our consolidated financial position or results of operations.

In September 2006, the SEC released Staff Accounting Bulletin 108 (SAB 108). SAB 108 provides interpretative guidance on how the effects of a carryover or reversal of prior year misstatements should be considered in quantifying a current year misstatement. SAB 108 is effective for fiscal years ending after November 15, 2006. We adopted this Statement in fiscal 2006, and its adoption did not have a material impact on our consolidated financial position or results of operations.

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. To date the foreign currency exchange rate risk has been inconsequential.

Table of Contents

Index to Financial Statements

Item 7A. Q*uantitative and Qualitative Disclosure about Market Risk*

Commodity Risk. Our major commodity price risk exposure is to the prices received for our natural gas production. Realized commodity prices received for our production are the spot prices applicable to natural gas. Prices received for natural gas are volatile and unpredictable and are beyond our control. For the year ended December 31, 2006, a 10% fluctuation in the prices received for natural gas production would have had an approximate $4.5 million impact on our revenues.

Interest Rate Risk. We have long-term debt subject to the risk of loss associated with movements in interest rates. As of December 31, 2006, we had $60 million of variable rate long-term debt outstanding due in January 2011. This variable rate obligation exposes us to the risk of increased interest expense in the event of increases in short-term interest rates. The impact on annual cash flow of a 10% change in the floating rate applicable to our variable rate debt would be approximately $.4 million.

Table of Contents

Index to Financial Statements

Item 8. ***Financial Statements and Supplementary Data***

GEOMET, INC. AND SUBSIDIARIES

Index To Financial Statements

Table of Contents

Index to Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have audited the accompanying consolidated balance sheets of GeoMet, Inc. and subsidiaries (the Company) as of December 31, 2006 and 2005 and the related consolidated statements of operations, stockholders equity and comprehensive (loss) income and cash flows for each of the three years in the period ended December 31, 2006. 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, such consolidated financial statements present fairly, in all material respects, the financial position of GeoMet, Inc. and subsidiaries as of December 31, 2006 and 2005, and the results of its operations and cash flows for each of the three years in the period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 123(R), Share-Based Payment on January 1, 2006.

/s/ DELOITTE & TOUCHE LLP

Houston, TX

March 19, 2007

Table of Contents

Index to Financial Statements

GEOMET, INC. AND SUBSIDIARIES

Consolidated Balance Sheets

	December 31, 2006	December 31, 2005
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 1,414,476	$ 615,806
Accounts receivable	10,881,479	5,577,140
Current portion of notes receivable	81,181	310,210
Deferred tax asset		2,911,808
Derivative asset	4,290,599	
Other current assets	648,053	414,232
Total current assets	17,315,788	9,829,196
Gas properties utilizing the full cost method of accounting:		
Proved gas properties	310,011,154	229,519,222
Unevaluated gas properties, not subject to amortization	26,397,982	20,680,712
Other property and equipment	2,314,190	1,841,056
Total property and equipment	338,723,326	252,040,990
Less accumulated depreciation, depletion, and amortization	(22,849,903)	(15,392,300)
Property and equipment net	315,873,423	236,648,690
Other noncurrent assets:		
Note receivable	298,936	323,879
Derivative asset	1,043,108	
Other	663,511	1,107,234
Total other noncurrent assets	2,005,555	1,431,113
TOTAL ASSETS	$ 335,194,766	$ 247,908,999
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Accounts payable	$ 14,284,921	$ 6,861,075
Derivative liability		8,931,926
Deferred tax liability	1,570,684	
Asset retirement liability	73,047	51,510
Accrued liabilities	2,917,575	1,265,989
Current portion of long-term debt	94,177	86,472
Total current liabilities	18,940,404	17,196,972
Long-term debt	60,832,110	99,926,378
Long-term derivative liability		2,611,592
Asset retirement liability	2,480,754	1,838,663
Other long-term accrued liabilities	154,455	258,573

Deferred income taxes	42,779,537	30,654,545
TOTAL LIABILITIES	125,187,260	152,486,723
Commitments and contingencies (Note 11)		
Stockholders Equity:		
Preferred stock, $0.001 par value authorized 10,000,000, none issued		
Common stock, $0.001 par value authorized 125,000,000, and 40,000,000 shares; issued and outstanding 38,678,713 and 29,974,664 at December 31, 2006 and 2005, respectively	38,679	29,975
Paid-in capital	186,852,852	106,408,915
Accumulated other comprehensive (loss) income	(193,888)	56,310
Retained earnings	23,740,144	6,443,928
Less notes receivable	(430,281)	(17,516,852)
TOTAL STOCKHOLDERS EQUITY	210,007,506	95,422,276
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 335,194,766	$ 247,908,999

See accompanying Notes to Consolidated Financial Statements

Table of Contents

Index to Financial Statements

GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

AND COMPREHENSIVE (LOSS) INCOME

	Years Ended December 31,		
	2006	2005	2004
Revenues:			
Gas sales	$ 44,952,027	$ 41,604,342	$ 19,521,447
Gas Marketing	13,043,598		
Operating fees and other	140,922	375,509	1,402,334
Total revenues	58,136,547	41,979,851	20,923,781
Expenses:			
Purchased gas	12,898,973		
Lease operating expense	11,579,112	8,687,550	5,091,046
Compression and transportation expense	4,498,850	3,332,045	1,951,316
Production taxes	1,037,401	913,885	473,222
Depreciation, depletion and amortization	7,876,212	4,867,134	2,691,320
Research and development	129,085	608,477	278,339
General and administrative	6,807,033	3,207,992	2,513,297
Realized (gains) losses on derivative contracts	(1,118,043)	7,473,004	814,940
Unrealized (gains) losses from the change in market value of open derivative contracts	(16,877,225)	12,059,208	(542,076)
Total operating expenses	26,831,398	41,149,295	13,271,404
Income from operations	31,305,149	830,556	7,652,377
Other income (expense):			
Interest income	33,149	76,569	69,553
Interest expense (net of amounts capitalized)	(3,130,005)	(3,894,550)	(985,949)
Other expenses	(9,773)	(21,366)	(4,174)
Total expense	(3,106,629)	(3,839,347)	(920,570)
Income (loss) before income taxes and minority interest, net of income tax	28,198,520	(3,008,791)	6,731,807
Income tax expense (benefit)	10,879,769	(993,174)	2,312,008
Net income (loss) before minority interest, net of income tax of $0	17,318,751	(2,015,617)	4,419,799
Minority interest	(22,535)	(442,336)	584,018
Net income (loss)	17,296,216	(1,573,281)	3,835,781
Other comprehensive income (loss)			
Foreign currency translation adjustment, net of income tax of $0	(250,198)	54,191	2,119
Comprehensive income (loss)	$ 17,046,018	$ (1,519,090)	$ 3,837,900
Earnings per common share:			
Basic			

Net income (loss) per share basic	$	0.49	$	(0.06)	$	0.17
Diluted						
Net income (loss) per share diluted	$	0.48	$	(0.06)	$	0.17
Weighted average number of common shares:						
Basic		35,018,122		28,164,946		22,710,384
Diluted		35,964,301		28,164,946		22,860,396

See accompanying Notes to Consolidated Financial Statements.

Table of Contents

Index to Financial Statements

GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

AND COMPREHENSIVE (LOSS) INCOME

	December 31,		
	2006	**2005**	**2004**
Common stock, $0.001 par value shares outstanding:			
Balance at beginning of year	29,974,664	24,000,000	