GeoMet, Inc.
Form 10-K
March 13, 2009

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, 2008

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	**(I.R.S. Employer**
incorporation or organization	**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, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ¨ Accelerated filer x Non-accelerated filer ¨ Smaller reporting company ¨

(Do not check if a smaller reporting company)

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

The aggregate market value of common stock, par value $0.001 per share, held by non-affiliates (based upon the closing sales price on the NASDAQ Global Market on June 30, 2008), the last business day of registrant s most recently completed second fiscal quarter was approximately $372 million.

As of March 1, 2009, 39,049,684 shares of the registrant s common stock, par value $0.001 per share, were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Information required by Part III, Items 10, 11, 12, 13 and 14, is incorporated by reference to portions of the registrant s definitive proxy statement for its 2009 annual meeting of stockholders, which will be filed on or before April 30, 2009.

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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 current 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. Other than as required under the securities laws, 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;
- difficult and adverse conditions in the global and domestic capital and credit markets;
- continued volatility and further deterioration of the capital and credit markets;
- the impairment of financial institutions;
- changes in general economic conditions, including the performance of financial markets and interest rates, which may affect our ability to raise capital and generate operating cash flow;
- hedging decisions, including whether or not to hedge;
- our hedging activities may prevent us from benefiting from price increases and may expose us to other risks;
- actions of third party co-owners of interests in properties in which we also own an interest;

fluctuations in interest rates and availability of capital;

foreign currency fluctuations could negatively affect the profitability of foreign operations;

competition in the gas industry;

declines in the prices we receive for our gas affecting our operating results, cash flows and credit capacity;

uncertainties in estimating our gas reserves;

replacing our gas reserves;

uncertainties in exploring for and producing gas;

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- the coalbeds and other strata from which we produce methane gas may contain impurities that may increase the cost of production;
- new gas development projects and exploration for gas in areas where we have little or no proven gas reserves;
- our ability to acquire water supplies needed for drilling, or our ability to dispose of water used or removed from strata at a reasonable cost and within applicable environmental rules;
- other persons could have ownership rights in our advanced gas extraction techniques which could force us to cease using those techniques or pay royalties;
- 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;
- 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
- our ability to retain and attract qualified personnel;
- our joint venture arrangements;
- the outcomes of various legal proceedings, which are more fully described in our reports filed under the Securities Exchange Act of 1934;
- the effects of government regulation and permitting and other legal requirements;
- the effects of stringent federal and state employee health and safety regulations;
- the effects of proposals to regulate greenhouse gas emissions; 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 is based on estimates prepared by independent engineers and is net to our interest.

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GLOSSARY OF NATURAL GAS AND COALBED METHANE TERMS

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

Additional drilling locations. Identified potential drilling locations on our existing acreage that are not included in our proved undeveloped reserves.

Appalachian Basin. A mountainous region in the eastern United States of America (U.S.), 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.

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

Finding and development costs. A 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 is calculated for the three year time period by taking the sum of the cost incurred for exploration, development, and acquisition 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 schedules of Capitalized Costs, Capitalized Costs Incurred, Natural Gas Reserves and Standardized Measure, which are all required to be disclosed by Statement of Financial Accounting Standards (SFAS) No. 69, *Disclosures about Oil and Gas Producing Activities an amendment of FASB Statements 19, 25, 33, and 39* (SFAS 69).

Gas desorption test. A process to estimate the volume of natural gas adsorbed in a volume of coal (usually expressed as cubic feet per ton) by placing a sample of coal into a sealed canister and taking periodic measurements of gas desorbed, temperature and pressure for up to 90 days. The estimate of total gas adsorbed in the coal sample is the sum of: (i) the measurements of 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.

Gas in-place. The total gas measured within any particular formation before any production. A portion of this total resource base is not economically recoverable. This portion varies due to the formation s reservoir characteristics such as pressure and permeability.

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

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

Mcf. Thousand cubic feet of natural gas.

MMBtu. Million British thermal units.

MMcf. Million cubic feet of natural gas.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or wells, 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.

PV-10 or present value of estimated future net revenues. An estimate of the present value of the estimated future net revenues from estimated proved natural gas reserves at a date indicated after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates of federal income taxes, a measure not in accordance with accounting principles generally accepted in the U.S. of

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America (GAAP), or a non-GAAP measure. The estimated future net revenues are discounted at an annual rate of 10% in accordance with the practice of the Securities and Exchange Commission (SEC), 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.

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.

Shale. A well hardened, very fine to fine grained sedimentary rock. Shale has ultra-low permeability and is formed from the compaction of silt, clay, or mud. Many shales contain a mixture of organic compounds called kerogen, which liberates natural gas during the maturation process of the shale. Gas within the shale can be stored onto the molecular surface of insoluble organic matter, trapped within the rock s pore space or present within open fractures.

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.

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PART I

Items 1 and 2. *Business and Properties*

Overview

GeoMet, Inc. is an independent energy company primarily engaged in the exploration for and development and production of natural gas from coal seams (coalbed methane or CBM) and non-conventional shallow gas. We were originally founded as a consulting company to the coalbed methane industry in 1985 and have been active as an operator and developer of coalbed methane properties since 1993. Our principal operations and producing properties are located in the Cahaba Basin in Alabama and the central Appalachian Basin in West Virginia and Virginia. We also control additional coalbed methane and oil and gas development rights, principally in Alabama, British Columbia, Virginia, and West Virginia. As of December 31, 2008, we control a total of approximately 213,000 net acres of coalbed methane and oil and gas development rights.

We primarily explore for, develop, and produce CBM and non-conventional shallow gas. Our objective is to create the premier non-conventional shallow gas company in North America (emphasizing coalbed methane) while maximizing stockholder value through the efficient investment of capital to increase reserves, production, cash flow and earnings. We believe that substantial expertise and experience is required to develop, produce, and operate coalbed methane and non-conventional shallow gas fields in an efficient manner. We believe that the inherent geologic and production characteristics of coalbed methane and non-conventional shallow gas offer significant operational advantages compared to conventional gas production.

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 the global economy and 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, material adverse outcomes from lawsuits 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.

Our proved natural gas reserves as of December 31, 2008 as estimated by DeGolyer and MacNaughton, independent petroleum engineers, totaled approximately 320 Bcf, a decrease of 8.6% from the approximate 350 Bcf of proved natural gas reserves at year-end 2007. Proved reserve estimates for the current year were calculated using an unescalated natural gas price of $5.71 per MMBtu, adjusted for regional price differentials, as compared to an unescalated natural gas price in the prior year of $7.46 per MMBtu.

Our proved reserves were 100% from unconventional reservoirs, were 99% from coalbed methane and were 77% developed. The present value of proved reserves discounted at ten percent was approximately $352 million at December 31, 2008 as compared to $663 million at year-end 2007. Although reserves declined from year-end 2007, before downward revisions and a property conveyance the Company replaced approximately 296% of its production in 2008. Downward revisions totaled approximately 42 Bcf of which approximately 13 Bcf resulted from lower natural gas prices. The remaining downward revisions were primarily in the Gurnee field in Alabama, resulting from production performance issues in certain sectors of the field.

Approximately 57% of total year-end 2008 proved reserves are in the Gurnee field in Alabama and 41% are in the Pond Creek and Lasher fields in West Virginia and Virginia. The Peace River project is the first commercial coalbed methane project in British Columbia, Canada and there are no other similar producing

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analogies in the region. As a result, initial proved developed reserves of only 4 Bcf were booked in 2008. Similarly, our Garden City project it is the first commercial Chattanooga Shale project in Alabama, and only 2 Bcf of initial proved reserves were booked in 2008.

Impact of Current Credit Market Conditions We believe that we are well-positioned for the current credit market environment. We have a healthy balance sheet with over $2 million in cash and a debt-to-book capital ratio of 38%. The borrowing base on our revolving credit facility was set at $140 million on March 12, 2009. Under the terms of the determination, our borrowing cost was increased by approximately 100 basis points and the fee on the undrawn portion of the borrowing base was increased by 12.5 basis points. If not extended, our credit facility will mature in January 2011. As of December 31, 2008, we were in compliance with all of the covenants in the credit agreement. All of our lenders are currently funding our borrowing requests.

Impact of Decreasing Natural Gas Prices We account for our gas properties using the full cost method and are required to impair a full cost pool when the net capitalized costs in the pool exceed the discounted future net revenues of the proved reserves associated with the pool. Based upon the lower natural gas prices at December 31, 2008, we have reported a non-cash impairment to our U.S. full cost pool of $20 million, net of income tax. Due to limited initial proved reserve bookings in the Peace River project we also reported a non-cash impairment to our Canadian full cost pool of $19 million, net of income tax.

If natural gas prices at March 31, 2009 are below those prices that existed at December 31, 2008, GeoMet expects to record a non-cash impairment to the Company s natural gas properties for the quarter then ended.

Our capital expenditure budget for 2009 will be funded from our estimated operating cash flows. If our cash flows are not sufficient to fund all of our estimated capital expenditures, we may reduce our capital budget. The amount and timing of our expenditures are subject to change based upon market conditions, results of expenditures and other factors. We routinely adjust our capital expenditure budget in response to changes in natural gas prices, drilling and acquisition costs, cash flow, drilling results and borrowing base redeterminations under our revolving credit facility. Based on current gas price projections, we expect capital expenditures to be less than the $24.1 million capital budget we previously announced.

Characteristics of Coalbed Methane and Non-Conventional Shallow Gas

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 from initial production 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 U.S., 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 U.S., 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.

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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. At shallow depths of less than 500 feet, these fractures often 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.

Areas of Operation

Cahaba Basin

We hold the development rights to approximately 44,000 net CBM acres throughout the Gurnee field in the Cahaba Basin of central Alabama. At December 31, 2008, approximately 57% of our estimated proved reserves, or 182.2 Bcf, were located in the Gurnee field, of which approximately 79% were classified as proved developed. We are the operator and own a 100% working interest in the area. As of December 31, 2008, we had 246 productive wells in the Gurnee field. Net daily sales of gas averaged approximately 6,123 Mcf for 2008.

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.

Our acreage is roughly evenly divided between a northern block, largely on the east side of the Cahaba River, and a southern block, largely on the west side of the river. The geology is generally more complex on the east side of the river with beds dipping from northwest to southeast. The geological setting west of the river tends to be less complex with more gently dipping beds. Most of the development to date in the Gurnee field has been on the east side of the river which is near existing infrastructure. In 2008, we drilled two test wells on the less geologically complex west side of the river in the southern acreage block. Production results for 2008 were encouraging with early initial gas production inclines and average gas production rates higher than elsewhere in the field.

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 maximum design capacity of approximately 45,000 barrels of water per day, but would require additional pump stations and looping a portion of the line in order to reach the maximum design capacity, if needed.

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. As we control the gathering and delivery pipeline system, we incur no third party costs to gather and deliver our gas to market. We believe we have adequate takeaway capacity to meet our future needs.

Garden City

The Garden City Chattanooga Shale prospect is located in north central Alabama. At December 31, 2008, we have approximately 72,000 net acres of leasehold. Approximately 1% of our estimated proved reserves, or 1.7 Bcf, were located within the field, all of which were classified as proved developed. As of December 31, 2008, we are the operator and own a 100% working interest in 3 productive wells. In 2009, we intend to seek a produced water disposal solution. We market the gas from this field to a local municipality through their pipeline system. We believe we have adequate takeaway capacity to meet our future needs.

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Pond Creek

In the Pond Creek field in the central Appalachian Basin of southern West Virginia and southwestern Virginia, we have the rights to develop approximately 33,000 net CBM acres. At December 31, 2008, approximately 37% of our estimated proved reserves, or 117.7 Bcf, were located within the Pond Creek field, of which approximately 77% were classified as proved developed. As of December 31, 2008, we are the operator and own an average 99% working interest in 242 gross productive wells in the Pond Creek field. Net daily sales of gas averaged approximately 13,670 Mcf for 2008. In 2009, we intend to drill 20 wells and related additional facilities in the Pond Creek field.

We extract gas from 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 low-medium volatile bituminous rank Pennsylvanian Age coal. Prior mining activity revealed that these coal groups are gas rich. A total of 42 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 Jewell Ridge pipeline system owned by East Tennessee Natural Gas, LLC (ETNG). In January 2007, we executed two long-term transportation agreements with ETNG which became effective when our pipeline was placed in service on April 1, 2007, with total maximum daily quantities of 15,000 MMBtu s and 10,000 MMBtu s and primary terms of 15 years and 10 years, respectively. We believe we have adequate takeaway capacity to meet our future needs.

Lasher

In the Lasher field in the central Appalachian Basin of southern West Virginia, we have the rights to develop approximately 17,000 net CBM acres. At December 31, 2008, approximately 4% of our estimated proved reserves, or 14.1 Bcf, were located within the Lasher field, of which approximately 42% were classified as proved developed. As of December 31, 2008, we are the operator and own a 100% working interest in 18 productive wells. Our gas from the Lasher field is delivered into the Columbia pipeline system for which we have firm transportation contracts continuing until October 31, 2011 with the right to extend these contracts, in five-year increments, at the maximum tariff rate. We believe we have adequate takeaway capacity to meet our future needs.

British Columbia

Our Peace River Project is comprised of approximately 25,000 net acres along the Peace River near Hudson s Hope, British Columbia. We have drilled 4 core holes targeting the medium volatile bituminous rank Lower Cretaceous Gething coals. Multiple, mostly thin, coal seams, with an aggregate average thickness of 52 feet, exist at depths from 1,000 to 3,000 feet. The Peace River project is the first commercial coalbed methane project in British Columbia, Canada and there are no other similar producing analogies in the region. As a result, initial proved developed reserves of only 3.8 Bcf were booked in 2008. At December 31, 2008, approximately 1% of our estimated proved reserves were located within the Peace River field, all of which were classified as proved developed. As of December 31, 2008, we own a 50% working interest in eight gross productive wells and we are the operator. Our gas from Peace River is delivered on a Spectra Energy Corp pipeline. There are two primary delivery options, namely Westcoast Station 2 in British Columbia and at Sumas, located near the U.S. and Canadian border. We believe we have adequate takeaway capacity to meet our future needs.

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Estimated Proved Reserves

The following table sets forth certain information with respect to our estimated proved reserves by field as of December 31, 2008. 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, 2008 is based on estimates made in a reserve report prepared by DeGolyer and MacNaughton.

	Estimated Proved Reserves				
Field	Proved Developed Producing (MMcf)	Proved Developed Non-Producing (MMcf)	Proved Undeveloped (MMcf)	Total Proved (MMcf)	PV-10(1) (In thousands)
Central Appalachia:					
Pond Creek field	90,643		27,015	117,657	$ 158,250
Lasher field	5,653	229	8,229	14,112	7,654
Alabama:					
Gurnee field	120,504	23,711	37,949	182,164	180,130
Garden City field	730	939		1,669	1,662
White Oak Creek field	109			109	412
Total U.S.	217,639	24,879	73,193	315,711	348,108
Canada:					
Peace River field	3,020	798		3,818	3,841
Total Gas Properties	220,659	25,677	73,193	319,529	$ 351,949

(1) PV-10, a non-GAAP measure, is our estimated present value of future net revenues from estimated proved reserves before income taxes. We believe PV-10 to be an important measure for evaluating the relative significance of our CBM gas properties and that PV-10 is widely used by professional analysts and investors in evaluating gas companies. Because many factors that are unique to each individual company impact the amount of future income taxes to be paid, the use of a pre-tax measure provides greater comparability of assets when evaluating companies. We believe that most other companies in the oil and gas industry calculate PV-10 on the same basis. Management also uses PV-10 in evaluating acquisition candidates. PV-10 only differs from the standardized measure of discounted future net cash flows (SMOG), as calculated and presented in accordance with SFAS 69, in that SMOG takes into account the present value of income taxes related to our future 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 prices of gas at December 31, 2008 used to estimate U.S. and Canadian proved reserves and future net revenue were \$5.84 per MMBtu and \$5.20 per MMBtu, respectively, and was calculated using the Henry Hub NYMEX cash price at December 31, 2008 of \$5.71 per MMBtu of gas, adjusted for price differentials at our sales points but excluding the effects of hedging.

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Production and Operating Statistics

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

	Year Ended December 31, 2008	2007	2006
Gas:			
Net sales volume (Bcf)	7.5	7.1	6.2
Average natural gas sales price ($ per Mcf)	$ 9.17	$ 6.97	$ 7.19
Average natural gas sales price ($ per Mcf) realized(1)	$ 9.10	$ 7.52	$ 7.37
Total production expenses ($ per Mcf)	$ 2.87	$ 2.86	$ 2.75
Expenses: ($ per Mcf)			
Lease operations expenses	$ 1.98	$ 1.96	$ 1.86
Compression and transportation expenses	$ 0.60	$ 0.73	$ 0.72
Production taxes	$ 0.29	$ 0.17	$ 0.17
Depletion of gas properties	$ 1.35	$ 1.24	$ 1.26
General and administrative	$ 1.26	$ 1.30	$ 1.05

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

Productive Wells and Acreage

The following table sets forth our interest in undeveloped acreage, developed acreage and productive wells in which we own a working interest as of December 31, 2008. 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		Developed Acres		Undeveloped Acres	
Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Gurnee	246.0	246.0	16,027	16,027	27,829	27,578
Garden City	3.0	3.0	240	240	82,513	72,062
Pond Creek	242.0	240.0	15,426	15,294	18,073	17,471
Lasher	18.0	18.0	1,407	1,407	15,270	15,251
Peace River	8.0	4.0	720	360	50,064	25,032
Other					22,470	22,470
Total	517.0	511.0	33,820	33,328	216,219	179,864

Our material undeveloped leases are in Alabama, which includes the Gurnee and Garden City fields, the Central Appalachian Basin, which includes the Pond Creek and Lasher fields, and Canada which includes the Peace River field. Generally, the undeveloped acreage expires on various dates from 2009 through 2013; however, the term of the undeveloped acreage can be extended by drilling and production operations. As to the Gurnee field, we have fulfilled drilling commitments on our largest lease, giving us the ability to postpone further drilling until 2010. Otherwise, the remaining acreage either has expirations that occur from 2009 through 2013 or the leases can be extended by drilling and production operations or option payments.

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Drilling Activity

The following table sets forth the number of completed gross exploratory and gross development wells drilled in the U.S. 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.

	Gross					
	Exploratory			Development		
Well Activity (Gross) U.S.	**Productive**	**Dry**	**Total**	**Productive**	**Dry**	**Total**
Year ended December 31, 2008	2		2	54		54
Year ended December 31, 2007	4		4	49		49
Year ended December 31, 2006	2		2	102		102

	Exploratory			Development		
Well Activity (Gross) Canada	**Productive**	**Dry**	**Total**	**Productive**	**Dry**	**Total**
Year ended December 31, 2008				5		5
Year ended December 31, 2007	1		1			
Year ended December 31, 2006	3		3			

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.

	Net					
	Exploratory			Development		
Well Activity (Net) U.S.	**Productive**	**Dry**	**Total**	**Productive**	**Dry**	**Total**
Year ended December 31, 2008	2.0		2.0	54.0		54.0
Year ended December 31, 2007	4.0		4.0	47.0		47.0
Year ended December 31, 2006	2.0		2.0	102.0		102.0

	Exploratory			Development		
Well Activity (Net) Canada	**Productive**	**Dry**	**Total**	**Productive**	**Dry**	**Total**
Year ended December 31, 2008				2.5		2.5
Year ended December 31, 2007	0.5		0.5			
Year ended December 31, 2006	1.5		1.5			

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.

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Strategy

Our objective is to create the premier non-conventional shallow gas company in North America (emphasizing coalbed methane) while maximizing stockholder value through the efficient investment of capital to increase reserves, production, cash flow and earnings. We intend to focus on the following strategies:

- Focus primarily on coalbed methane and non-conventional shallow gas to exploit our substantial expertise and experience.
- Maximize present value in existing development projects and expand into adjacent areas to leverage our information, knowledge and infrastructure.
- Develop new large scale projects, maintain operational control and reduce costs through economies of scale.
- Maintain financial discipline.

Competitive Strengths

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

- *Production Rates*. Unlike conventional and unconventional 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 Costs*. Our costs of finding and developing coalbed methane tend to be low compared to industry averages because our well costs are generally lower due to the relatively shallow depths of gas-bearing coal seams underlying our projects. Coal seams possess the ability to store significantly more gas volumetrically at shallow depths than conventional reservoirs. In the early stages of a CBM project development per unit operating costs are higher because natural gas production per well is initially low and many of our costs are fixed. As average production per well from a project increases over time 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 costs of finding, developing and producing natural gas will be lower than those of many conventional and unconventional natural 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 18-person CBM management, professional, and project management team has an average of more than 18 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. Our extensive undeveloped acreage position provides us with an additional 582 net drilling locations.

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Track Record of Success in Identifying and Exploiting Large Underdeveloped Resource Plays. We pursue those projects that leverage our CBM expertise to exploit underdeveloped resource potential and shallow gas. We have a history of developing large scale projects in multiple basins with low finding and development costs.

Changes in Global Economy

The global financial and capital markets have been experiencing extreme volatility and disruption, including the failures of financial services companies and the related liquidity crisis. The sharp economic downturn during 2008 was prompted by a combination of factors: tight credit markets, speculation and fear regarding the health of the U.S. and global financial systems, and weaker economic activity including a global economic recession.

Natural gas exploration companies are capital intensive and, as such, rely on the credit markets for liquidity and for the financing of natural gas exploration. In addition, economic recessions historically result in lower market demand, resulting in lower prices. A prolonged period of low gas prices may have a material impact on our cash generation, although in the near term this would be mitigated by our hedged position of our natural gas production. Although we expect to meet our near term liquidity needs with our working capital on hand, we will continue to need further funding to achieve our business objectives. If the disruptions in the global financial and capital markets continue, debt or equity financing may not be available to us on acceptable terms, if at all. If we are unable to fund future operations by way of financing, including public or private offerings of equity or debt securities, our business, financial condition and results of operations will be adversely impacted.

Our operations are affected by local, national and worldwide economic conditions. The consequences of a prolonged recession could include a lower level of economic activity and uncertainty regarding energy prices and the capital and commodity markets. A lower level of economic activity could result in a decline in energy consumption, which could adversely affect our revenues and future growth. Instability in the financial markets, as a result of recession or otherwise, also could affect the cost of capital and our ability to raise capital.

Competition

Our operations primarily compete regionally in the U.S. and Canada. Competition throughout the U.S. and Canada 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.

Seasonality of Business

Weather conditions affect the demand for and prices of natural gas and can also delay drilling activities, disrupting our overall business plans. Demand for natural gas is typically higher in the fourth and first quarters resulting in higher natural gas prices. Due to these seasonal fluctuations, results of operations for individual quarterly periods may not be indicative of the results that may be realized on an annual basis.

Governmental, State and Local 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 are subject.

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Regulation by the Federal Energy Regulatory Commission (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 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

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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 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.

Virginia Regulation. The Virginia Supreme Court has stated that the grant of coal rights only does not include rights to coalbed methane absent an express grant of coalbed methane, natural gases, or minerals in general. The situation may be different if there is any expression in the severance deed indicating more than mere coal is conveyed. Virginia courts have also found that the owner of the coalbed methane did not have the right to fracture the coal in order to retrieve the coalbed methane and that the coal operator had the right to ventilate the coalbed methane in the course of mining. In Virginia, we believe that we control the relevant property rights in order to capture gas from the vast majority of our producing properties. In addition, Virginia has established the Virginia Gas and Oil Board and a procedure for the development of coalbed methane by an operator in those instances where the owner of the coalbed methane has not leased it to the operator or in situations where there are conflicting claims of ownership of the coalbed methane. The general practice is to force pool both the coal owner and the gas owner. In those instances, any royalties otherwise payable are paid into escrow and the burden then is upon the conflicting claimants to establish ownership by court action. The Virginia Gas and Oil Board does not make ownership decisions.

West Virginia Regulation. The West Virginia s Supreme Court has held that, in a conventional oil and gas lease executed prior to the inception of widespread public knowledge regarding coalbed methane operations, the oil and gas lessee did not acquire the right to produce coalbed methane. As of December 31, 2008, the West Virginia courts have not clarified who owns coalbed methane in West Virginia. Therefore, the ownership of coalbed methane is an open question in West Virginia. West Virginia has enacted a law, the Coalbed Methane Wells and Units Act (the West Virginia Act), regulating the commercial recovery and marketing of coalbed methane. Although the West Virginia Act does not specify who owns, or has the right to exploit, coalbed methane in West Virginia and instead refers ownership disputes to judicial resolution, it contains provisions similar to Virginia s pooling law. Under the pooling provisions of the West Virginia Act, an applicant who proposes to drill can prosecute an administrative proceeding with the West Virginia Coalbed Methane Review Board to obtain authority to produce coalbed methane from pooled acreage. Owners and claimants of coalbed methane interests who have not consented to the drilling are afforded certain elective forms of participation in the drilling (e.g., royalty or owner) but their consent is not required to obtain a pooling order authorizing the production of coalbed methane by the operator within the boundaries of the drilling unit. The West Virginia Act also provides that, where title to subsurface minerals has been severed in such a way that title to coal and title to natural gas are vested in different persons, the operator of a coalbed methane well permitted, drilled and

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completed under color of title to the coalbed methane from either the coal seam owner or the natural gas owner has an affirmative defense to an action for willful trespass relating to the drilling and commercial production of coalbed methane from that well.

Alabama Regulation. In 1983 the State Oil & Gas Board of Alabama, in cooperation with the coalbed methane operator s group, established the first rules for coalbed methane drilling, development and production operations. The evolution of Alabama coalbed methane permits is a continuing process. The coalbed methane industry in Alabama has a long history of working closely with Alabama Department of Environmental Management and other government agencies on the continual improvement of coalbed methane permits.

Canadian Governmental Regulation. Our operations in Canada are subject to regulation by the National Energy Board (NEB) and provincial agencies in Canada. These agencies have jurisdiction similar to the FERC for regulation. Business in Western Canada is regulated by the NEB pursuant to a framework for light-handed regulation under which the NEB acts on a complaints basis. However, the natural gas industry in Canada remains subject to extensive controls and regulations imposable by various levels of government. We do not expect that any of these controls or regulations will affect our operations in a manner materially different than they would affect other natural gas industry participants of similar size.

In addition to federal regulation, each province has legislation and regulations that govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability natural gas production. Royalties payable on production from lands other than government lands are determined by negotiations between the mineral owner and the lessee. Royalties on government land are determined by government regulation and are generally calculated as a percentage of the value of gross production, and the rate of royalties payable generally depends upon prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced.

NAFTA. The North American Free Trade Agreement among the governments of Canada, the U.S. and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada-U.S. Free Trade Agreement. Subject to the General Agreement on Tariffs and Trade, Canada continues to remain free to determine whether exports of energy resources to the U.S. or Mexico will be allowed, so long as any export restrictions do not reduce the proportion of energy resources exported relative to total supply (based upon the proportion prevailing in the most recent 36-month period or another representative period agreed upon by the parties), impose an export price higher than the domestic price (subject to an exception that applies to some measures that only restrict the value of exports), or disrupt normal channels of supply. All three countries are prohibited from imposing minimum or maximum export or import price requirements, with some limited exceptions.

Environmental Regulations

Our coalbed methane exploration and production operations are subject to significant federal, state, local, and Canadian 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 drilling, production, and processing activities; suspend, limit or prohibit construction, drilling and other activities in certain lands lying within wilderness, wetlands and other protected areas; require remedial measures to mitigate pollution from historical and on-going operations such as the use of pits and plugging of abandoned wells; and restrict injection of liquids into subsurface strata that may contaminate groundwater. Governmental authorities have the power to enforce compliance with their laws, regulations and permits, and violations are subject to injunction, as well as administrative, civil and even criminal penalties. The effects of these laws and regulations, as well as other laws or regulations that are adopted in the future could have a material adverse impact on our operations.

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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 U.S. 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 natural gas industry, in general.

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 U.S., 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

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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 U.S., 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 U.S. 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 U.S. 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.

Canadian Environmental Regulation. The natural gas industry is governed by environmental regulation under Canadian federal and provincial laws, rules and regulations, which restrict and prohibit the release or emission and regulate the storage and transportation of various substances produced or utilized in association with natural gas industry operations. In addition, applicable environmental laws require that well and facility sites be abandoned and reclaimed, to the satisfaction of provincial authorities, in order to remediate these sites to near natural conditions. Also, environmental laws may impose upon responsible persons remediation obligations on property designated as a contaminated site. Responsible persons include persons responsible for the substance causing the contamination, persons who caused the release of the substance and any present or past

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owner, tenant or other person in possession of the site. Compliance with such legislation can require significant expenditures. A breach of environmental laws may result in the imposition of fines and penalties and suspension of production, in addition to the costs of abandonment and reclamation.

Industry Segment and Geographic Information

We operate in one industry, which is the exploration, development and production of natural gas. Our operational activities are conducted in the U.S. and Canada with only the U.S. currently having revenue generating operating results.

Employees

At December 31, 2008, we had 89 full-time employees and two full-time contractors. 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.

Corporate Offices

Our corporate headquarters are located at 909 Fannin, Suite 1850, Houston, Texas 77010. Our technical and operational headquarters are located at 5336 Stadium Trace Parkway, Suite 206, Birmingham, Alabama 35244.

Access to Company Reports

We file periodic reports, proxy statements and other information with the SEC in accordance with the requirements of the Exchange Act of 1934, as amended, or the Securities Exchange Act of 1934, as amended. We make our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to such reports available free of charge through our corporate website at *www.geometinc.com* as soon as reasonably practicable after we file any such report with the SEC. In addition, information related to the following items, among other information, can be found on our website: our press releases, our corporate governance guidelines, our corporate code of business ethics and conduct, our audit committee charter, our compensation committee charter and our nominating, corporate governance and ethics committee charter. You may also read and copy any document we file with the SEC at the SEC s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains an internet site that contains our reports, proxy and information statements, and our other filings which are also available to the public over the internet at the SEC s website at *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;

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

Many of these factors are beyond our control. Because all of our estimated proved reserves as of December 31, 2008 were natural gas reserves, our financial results are sensitive to movements in natural gas prices. Recent natural gas prices have been extremely volatile and we expect this volatility to continue. For example, from January 1, 2008 to February, 10, 2009, the NYMEX natural gas spot price ranged from a high of $13.54 per MMBtu to a low of $4.48 per MMBtu.

The results of higher investment in the exploration for and production of gas and oil and other factors, such as global economic and financial conditions discussed below, may cause the price of gas to fall. 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 substantial downward adjustments to our estimated proved reserves and could have a material adverse effect on our financial condition, results of operations and cash flow. If there are substantial downward adjustments to our estimated proved reserves 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.

If natural gas prices decline significantly for an extended period of time, we may, among other things, be unable to maintain or increase our borrowing capacity, repay current or future indebtedness or obtain additional capital on attractive terms, all of which can affect the value of our common stock.

The deterioration of global economic and financial conditions and an prolonged decline in the price of natural gas may materially and adversely affect our business, financial condition and results of operations.

Our business, financial condition and results of operations are affected by conditions in the capital markets and the economy generally. The recent global financial crisis and worldwide economic slowdown could lead to prolonged national or global recession, which would likely reduce domestic and foreign demand for natural gas and result in lower natural gas prices. Substantial decreases in natural gas prices could have a material adverse effect on our business, financial condition and results of operations, could limit our access to liquidity and credit and could hinder our ability to fund our development program, which would limit our ability to grow or replace our proved reserves, and, eventually, our production levels.

If credit and capital markets worsen, then we may not be able to obtain funding under our current revolving credit facility or fund on acceptable terms. The inability to obtain funding could deter us from meeting our future capital needs to fund our development program.

Capital and credit markets have experienced unprecedented volatility and disruption and continue to be unpredictable. Given the current levels of market volatility and disruption, the availability of funds from those markets has diminished substantially. Further, arising from concerns about the stability of financial markets

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generally and the solvency of counterparties specifically, the cost of accessing the credit markets has increased as many lenders have raised interest rate spreads, enacted tighter lending standards or altogether ceased to provide funding to borrowers. Additionally, even if lenders continue and are able to provide funding to borrowers, interest rates may rise in the future and therefore increase the cost of outstanding borrowings that we may incur under our revolving credit facility.

Moreover, we may be unable to obtain adequate funding under our current credit facility. First, our lenders may be unwilling or unable to meet their funding commitments. Second, our borrowing base under our credit facility is redetermined semiannually. Our lenders completed their latest redetermination on March 12, 2009 and set our borrowing base at $140 million. Under the terms of the determination, our borrowing cost was increased by approximately 100 basis points and the fee on the undrawn portion of the borrowing base was increased by 12.5 basis points. Our lenders have substantial ability to reduce our borrowing base on the basis of subjective factors. If natural gas prices significantly decline for an extended period of time, our lenders could redetermine our borrowing base by evaluating our reserves in light of such lower natural gas prices. Such determination could result in a negative revision to the value of our proved reserves and a reduction of our borrowing base.

As a result of these capital and credit market conditions, we cannot be certain that funding will be available if needed, and to the extent required, on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, we may not be able to meet our obligations as they come due or be required to post collateral to support our obligations, or we may not be able to implement our development program, grow our existing business through acquisitions, or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our business, financial condition and results of operations.

Changes in tax laws may impair our results of operations and adversely impact the value of our common stock.

Under current federal tax laws, we are entitled to certain deductions relating to our operations, including deductions for intangible drilling costs, manufacturing tax deductions and percentage depletion deductions. The President s budget for the fiscal year 2010 outlines proposals to eliminate several oil and gas federal income tax incentives, including the repeal of the manufacturing tax deduction and percentage depletion allowance for oil and natural gas and expensing of intangible drilling costs. It is not possible at this time to predict how legislation or new regulations that may be adopted to address these proposals would impact our business, but any such future laws and regulations could adversely affect the amount of our taxable income or loss and could have a negative impact on the value of our common stock.

We may incur substantial costs to comply with, and demand for our products may be reduced by, climate change legislation and regulatory initiatives.

The United States Congress is considering legislation to reduce emissions of greenhouse gases and more than one-third of the states, either individually or through multi-state initiatives, already have begun implementing legal measures to reduce emissions of greenhouse gases. In addition, the Environmental Protection Agency has announced possible future regulation of greenhouse gas emissions under the Clean Air Act. Depending on the nature of potential regulations and legislation, such future laws and regulations could result in increased compliance costs or additional operating restrictions, and could have an adverse effect on our business or demand for the natural gas we produce.

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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 industry in general.

Our results of operations could be adversely affected as a result of non-cash impairments.

At December 31, 2008, we recorded a full cost ceiling impairment of approximately $50.7 million. The full cost ceiling calculation dictates that prices and costs in effect as of the last day of the quarter are held constant. Future adverse changes to any of these factors could lead to an impairment of all or a portion of our full cost pool in future periods which could significantly reduce earnings during the period in which the impairment occurs, and would result in a corresponding reduction to the full cost pool and stockholders equity.

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 pressuring process. The rate of decline from our existing wells may change in a manner different than we have estimated. Thus, our future natural gas

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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 sell 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.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage.

As of December 31, 2008, we own leasehold interests in approximately 72,000 net acres in areas we believe are prospective for the Chattanooga Shale. A large portion of the acreage is not currently held by production. Unless production in paying quantities is established on units containing these leases during their terms, these leases will expire. If our leases expire, we will lose our right to develop the related properties. Our drilling plans for these areas are subject to change based upon various factors, including factors that are beyond our control, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals.

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

- unexpected drilling conditions;

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- title problems;
- pressure or irregularities in geologic formations;
- equipment failures or repairs;
- fires or other accidents;
- adverse weather conditions;
- reductions in natural gas prices;
- pipeline ruptures;
- regulatory permitting problems;
- inability to dispose of produced water;
- legal issues; 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 reserves and 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 and production.

Historically, we have financed our business plan and operations primarily with internally generated cash flow, bank borrowings, and issuances of common stock. 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 prohibiting our ability to incur additional indebtedness without the consent of the lenders. There can be no assurance that our lenders 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.

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

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Our revolving credit facility contains a number of financial and other covenants, and our obligations under the revolving 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 revolving 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 revolving credit facility to comply with certain financial ratios. Our revolving credit facility also provides for periodic redeterminations of our borrowing base, which may affect our borrowing capacity. Our revolving credit facility is secured by a lien on substantially all of our assets, including equity interests in our subsidiaries.

A breach of any of the covenants imposed on us by the terms of our revolving 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 revolving credit facility. Any acceleration in the repayment of our indebtedness or related foreclosure could adversely affect our business.

In addition, the borrowing base under our revolving 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 natural gas prices and reserve levels.

Our revolving credit facility expires in January 2011.

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 U.S. 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.

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.

Our ability to produce natural gas may be hampered by the water present in the formation, which could affect our profitability.

Unlike conventional natural gas production, coalbeds and shales frequently contain brine 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;

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- 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.

Obtaining production from our additional drilling locations could take five years or longer, making them susceptible to uncertainties that could alter the occurrence of their drilling.

The additional drilling locations on our existing acreage represent a significant part of our growth strategy. Our ability to drill and produce these locations depends on a number of uncertainties, including, but not limited to, natural gas prices, permitting and the availability of capital. Furthermore, the additional drilling locations on acreage in our two early-stage CBM development projects and our Chattanooga Shale exploration prospect face additional uncertainties regarding the economic returns achievable in these areas where only a few wells have been drilled to date.

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 a 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 U.S. 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 U.S. 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 other key personnel that have 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 operations 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 operations 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

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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 cost of 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, consents from third parties may be required 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 depend on technology owned by others.

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 availability or high cost of drilling rigs, equipment, supplies, personnel, and field 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 field services has risen, and the costs of these services are increasing. If the availability 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.

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Hedging transactions may limit our potential gains.

In order to manage our interest rate exposure and natural gas price risks, we have entered into interest rate swaps and natural gas price hedging arrangements with respect to a portion of our expected production. We will most likely enter into additional hedging transactions in the future. While intended to reduce the effects of volatile interest rates and natural gas prices, such transactions may limit our potential gains or increase our potential losses.

We do not insure against all potential 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.

Risks Related to Our Capital Stock

Our common stock has experienced, and may continue to experience, price volatility and a low trading volume.

The trading price of our common stock has been and may continue to be subject to large fluctuations, which may result in losses to investors. Our stock price may increase or decrease in response to a number of events and factors, including:

- results of our drilling or the results of drilling by offset operators;
- global economic recession;
- trends in our industry and the markets in which we operate;
- changes in the market price of the natural gas we sell;
- changes in financial estimates and recommendations by securities analysts;
- acquisitions and financings;
- quarterly variations in operating results;
- operating and stock price performance of other companies that investors may deem comparable to us; and

issuances, purchases or sales of blocks of our common stock.

This volatility may adversely affect the price of our common stock regardless of our operating performance.

Shares eligible for future sale may cause the market price for our common stock to drop significantly, even if our business is doing well.

If our existing shareholders sell our common stock in the market, or if there is a perception that significant sales may occur, the market price of our common stock could drop significantly. In such case, our ability to raise

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additional capital in the financial markets at a time and price favorable to us might be impaired. In addition, our board of directors has the authority to issue additional shares of our authorized but unissued common stock without the approval of our shareholders, subject to certain limitations under the rules of the exchange on which our common stock is listed. Additional issuances of our common stock would dilute the ownership percentage of existing shareholders and may dilute the earnings per share of our common stock.

We have not previously paid dividends on our common stock and we do not anticipate doing so in the foreseeable future.

We have not in the recent past paid, and do not anticipate paying in the foreseeable future, cash dividends on our common stock. Our outstanding revolving bank credit agreement contains covenants that restrict our ability to pay dividends on our common stock. Additionally, any future decision to pay a dividend and the amount of any dividend paid, if permitted, will be made at the discretion of our board of directors.

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

None.

Item 3. ***Legal Proceedings***

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

CNX Surface Use Disputes

Buchanan County Dispute. On September 12, 2008, the Virginia Supreme Court issued its decision in this matter in favor of us and PMC, reversing and remanding the matter to the Buchanan Circuit Court for further action consistent with the decision. The Court held that CNX Gas Company LLC (CNX) does not have the exclusive right to transport gas across the Pocahontas Mining Limited Liability Company (PMC) property and may not prevent uses of the PMC property that do not conflict with the exercise of CNX s rights under its CBM lease with PMC. The effect of this ruling is that our pipeline right of way with PMC is valid.

Tazewell County Dispute. 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 tract 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 Pond Creek gathering line across the property. We and CNX have since reached a resolution of this dispute. The settlement had no material impact on our financial position, results of operations, or cash flows presented herein.

CNX Antitrust Action

We filed a complaint against CNX and Island Creek Coal Company (Island Creek), an affiliate of CNX, in the Circuit Court of Tazewell County, Virginia on February 14, 2007, in which we sought 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 sought 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

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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 alleged CNX s intentional interference with our existing and prospective third-party business relationships in an attempt to harm us and improve CNX s position and corporate and financial interests. In accordance with an opinion issued by the Tazewell Circuit Court in December 2007, we have filed an amended petition that restates with specificity our claims against CNX and Island Creek, names Cardinal States Gathering Company and CONSOL Energy Inc., the ultimate parent of the other defendants, as additional defendants, and seeks actual damages of $385.6 million. We are seeking treble damages for the alleged violations of the Virginia Antitrust Act, as well as injunctive relief to prevent CNX and other parties from continuing these alleged anticompetitive activities.

Environmental and Regulatory

As of December 31, 2008, there were no known environmental or other regulatory matters related to our operations that are reasonably expected to result in a material liability to us.

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

None.

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PART II

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

Our common stock is listed on the NASDAQ Global Market 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
Fiscal Year 2007:		
Quarter ended March 31, 2007	$ 10.34	$ 7.73
Quarter ended June 30, 2007	$ 9.67	$ 7.26
Quarter ended September 30, 2007	$ 7.75	$ 5.09
Quarter ended December 31, 2007	$ 5.49	$ 4.86
Fiscal Year 2008:		
Quarter ended March 31, 2008	$ 7.28	$ 4.21
Quarter ended June 30, 2008	$ 9.52	$ 6.38
Quarter ended September 30, 2008	$ 9.40	$ 5.04
Quarter ended December 31, 2008	$ 5.32	$ 1.36

Approximately 1,500 stockholders of record as of December 31, 2008 held our common stock. In many instances, a registered stockholder is a broker or other entity holding shares in street name for one or more customers who beneficially own the shares. 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 revolving credit facility prohibits us from paying any cash dividends.

Changes in Securities, Use of Proceeds and Issuer Purchases of Equity Securities

We did not purchase any of our equity securities during the fourth quarter of 2008. In addition, we did not sell any of our equity securities which were not registered under the Securities Act of 1933, as amended, during the fourth quarter of 2008.

Equity Compensation Plan Information

The following table summarizes information regarding the number of shares of our common stock that are available for issuance under all of our existing equity compensation plans as of December 31, 2008.

Plan Category	Number of securities to be issued upon exercise of outstanding options	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column)
Equity compensation plans approved by security holders	1,757,256	$ 5.01	1,209,891(1)

Equity compensation plans not approved by security holders			
Total	1,757,256	$ 5.01	1,209,891

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(1) In 2006, our board of directors and stockholders approved the GeoMet, Inc. 2006 Long-Term Incentive Plan under which 2,000,000 shares of our common stock were reserved for awards to be granted. In conjunction with the approval of the 2006 Plan, no additional awards have been or will be granted under our 2005 Plan; however, we will continue to issue shares of our common stock upon exercise of awards that we have previously granted. The 1,209,891 of securities remaining available for future issuance includes 242,448 shares that were reserved but not granted under our 2005 Plan.

Performance Graph

The following performance graph and related information shall not be deemed soliciting material or to be filed with the SEC, 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 listed on the Nasdaq Global Market, through December 31, 2008 and compares it with the cumulative total return on the Russell 2000 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.

COMPARISON OF CUMULATIVE TOTAL RETURN

	7/28/06	12/31/06	12/31/07	12/31/08
GeoMet, Inc.	100.00	94.80	47.40	15.68
Russell 2000 Index	100.00	112.52	109.43	71.35
S&P Oil & Gas	100.00	97.01	132.82	75.92

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

The following table shows our selected historical consolidated financial and operating data as of and for each of the last five years ended December 31, 2008. The selected historical audited consolidated financial and operating data for the three years ended December 31, 2008 are derived from our audited financial statements included herein. The selected historical audited consolidated financial and operating data for the two years ended December 31, 2004 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 Management s 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.

	2008	2007	2006	2005	2004
STATEMENT OF OPERATIONS (in thousands):					
Total revenues	$ 69,094	$ 50,984	$ 44,947	$ 41,980	$ 20,924
Realized (gain) losses on derivative contracts	$ 500	$ (3,895)	$ (1,118)	$ 7,473	$ 815
Unrealized (gains) losses from the change in market value of open derivative contracts	$ (4,993)	$ 3,007	$ (16,877)	$ 12,059	$ (542)
Impairment of gas properties	$ 50,734				
Total operating expenses	$ 87,590	$ 37,852	$ 13,678	$ 41,149	$ 13,272
Operating (loss) income from continuing operations	$ (18,496)	$ 13,132	$ 31,269	$ 831	$ 7,652
Interest expense, net of amounts capitalized	$ (4,783)	$ (5,130)	$ (3,130)	$ (3,895)	$ (986)
(Loss) income before income taxes, minority interest, discontinued operations and cumulative effect of change in accounting principle	$ (23,199)	$ 7,983	$ 28,162	$ (3,008)	$ 6,732
Income tax expense (benefit)	$ (712)	$ 2,988	$ 10,866	$ (993)	$ 2,312
(Loss) income before minority interest, discontinued operations and cumulative effect of change in accounting principle, net of income tax	$ (22,487)	$ 4,995	$ 17,296	$ (2,015)	$ 4,420
Discontinued operations, net of income tax		$ 174	$ 23		
Minority interest, net of income tax			$ (23)	$ 442	$ (584)
Income (loss) from discontinued operations		$ 174		$ 442	$ (584)
(Loss) income from continuing operations before cumulative effect of change in accounting principle, net of income tax	$ (22,487)	$ 5,169	$ 17,296	$ (1,573)	$ 3,836
Cumulative effect of change in accounting principle, net of income tax					
Net (loss) income	$ (22,487)	$ 5,169	$ 17,296	$ (1,573)	$ 3,836
EARNINGS PER COMMON SHARE (in dollars):					
(Loss) Income from continuing operations					
Basic	$ (0.58)	$ 0.13	$ 0.49	$ (0.07)	$ 0.17
Diluted	$ (0.58)	$ 0.13	$ 0.48	$ (0.07)	$ 0.17
Discontinued operations					
Basic				$ 0.02	
Diluted				$ 0.02	
Net (loss) income per common share					
Basic	$ (0.58)	$ 0.13	$ 0.49	$ (0.06)	$ 0.17
Diluted	$ (0.58)	$ 0.13	$ 0.48	$ (0.06)	$ 0.17
BALANCE SHEET DATA (in thousands, at period end):					
Working (deficit) capital(1)	$ (1,441)	$ (2,063)	$ (1,625)	$ (7,368)	$ (1,251)
Total assets (including impairment of gas properties)	$ 377,600	$ 378,677	$ 335,195	$ 247,909	$ 142,090
Long-term debt	$ 117,118	$ 96,730	$ 60,832	$ 99,926	$ 51,513
Stockholders equity	$ 192,432	$ 218,676	$ 210,007	$ 95,422	$ 65,692
Cash flow data (in thousands):					
Net cash provided by operating activities	$ 32,958	$ 17,487	$ 21,472	$ 12,433	$ 10,580
Net cash used in investing activities	$ (52,719)	$ (53,832)	$ (78,669)	$ (59,661)	$ (66,193)
Net cash provided by financing activities	$ 20,493	$ 36,191	$ 58,086	$ 44,906	$ 50,192
Capital expenditures	$ 52,797	$ 54,026	$ 79,061	$ 59,817	$ 86,189
OTHER DATA:					
Net sales volume (Bcf)	7.5	7.1	6.2	4.6	3.2
Average natural gas sales price ($ per Mcf)(2)	$ 9.17	$ 6.97	$ 7.19	$ 9.06	$ 6.12
Average natural gas sales price ($ per Mcf) realized(3)	$ 9.10	$ 7.52	$ 7.37	$ 7.43	$ 5.87
Total production expenses ($ per Mcf)	$ 2.87	$ 2.86	$ 2.75	$ 2.81	$ 2.36

Depletion of gas properties($ per Mcf)	$	1.35	$	1.24	$	1.26	$	1.06	$	0.84
Estimated proved reserves (Bcf)(4)		319.5		350.2		325.7		262.5		209.9
Standardized measure of discounted future net cash flows ($ millions)	$	310.3	$	495.9	$	359.5	$	632.7	$	349.8
Non-GAAP Measures:(5)										
PV-10 ($ millions)	$	351.9	$	662.8	$	525.6	$	880.2	$	481.8

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(1) Working capital (deficit) is defined as current assets less current liabilities and is unaudited.
(2) Our natural gas sales price at December 31, 2008 was $5.84 per Mcf.
(3) Average realized price includes the effects of realized gains on derivative contracts.
(4) 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.
(5) See reconciliation of non-GAAP financial measures.

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,				
	2008	2007	2006	2005	2004
			(In thousands)		
Future cash inflows	$ 1,865,131	$ 2,654,214	$ 1,858,104	$ 2,536,279	$ 1,302,830
Less: Future production costs	734,911	725,272	501,956	463,416	290,425
Less: Future development costs	105,737	106,356	101,777	76,297	38,242
Future net cash flows	1,024,483	1,822,586	1,254,371	1,996,566	974,163
Less: 10% discount factor	672,534	1,159,780	728,739	1,116,413	(492,339)
PV-10	351,949	662,806	525,632	880,153	481,824
Less: Undiscounted income taxes	(423,795)	(724,399)	(410,391)	(579,689)	(274,975)
Plus: 10% discount factor	382,193	557,461	244,245	332,201	142,906
Discounted income taxes	(41,602)	(166,938)	(166,146)	(247,488)	(132,069)
Standardized measure of discounted future net cash flows	$ 310,347	$ 495,868	$ 359,486	$ 632,665	$ 349,755

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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

GeoMet, Inc. is an independent energy company primarily engaged in the exploration for and development and production of natural gas from coal seams (coalbed methane or CBM) and non-conventional shallow gas. We were originally founded as a consulting company to the coalbed methane industry in 1985 and have been active as an operator and developer of coalbed methane properties since 1993. Our principal operations and producing properties are located in the Cahaba Basin in Alabama and the central Appalachian Basin in West Virginia and Virginia. We also control additional coalbed methane and oil and gas development rights, principally in Alabama, British Columbia, Virginia, and West Virginia. As of December 31, 2008, we control a total of approximately 213,000 net acres of coalbed methane and oil and gas development rights.

Our proved natural gas reserves as of December 31, 2008 as estimated by DeGolyer and MacNaughton, independent petroleum engineers, totaled approximately 320 Bcf, a decrease of 8.6% from the approximate 350 Bcf of proved natural gas reserves at year-end 2007. Proved reserve estimates for the current year were calculated using an unescalated natural gas price of $5.71 per MMBtu, adjusted for regional price differentials, as compared to an unescalated natural gas price in the prior year of $7.46 per MMBtu.

Our proved reserves were 100% from unconventional reservoirs, were 99% from coalbed methane and were 77% developed. The present value of proved reserves discounted at ten percent was approximately $352 million at December 31, 2008 as compared to $663 million at year-end 2007. Although reserves declined from year-end 2007, before downward revisions and a property conveyance the Company replaced approximately 296% of its production in 2008. Downward revisions totaled approximately 42 Bcf of which approximately 13 Bcf resulted from lower natural gas prices. The remaining downward revisions were primarily in the Gurnee field in Alabama, resulting from production performance issues in certain sectors of the field.

Approximately 57% of total year-end 2008 proved reserves are in the Gurnee field in Alabama and 41% are in the Pond Creek and Lasher fields in West Virginia and Virginia. The Peace River project is the first commercial coalbed methane project in British Columbia, Canada and there are no other similar producing analogies in the region. As a result, initial proved developed reserves of only 4 Bcf were booked in 2008. Similarly, our Garden City project it is the first commercial Chattanooga Shale project in Alabama, and only 2 Bcf of initial proved reserves were booked in 2008.

Impact of Current Credit Market Conditions We believe that we are well-positioned for the current credit market environment. We have a healthy balance sheet with over $2 million in cash and a debt-to-book capital ratio of 38%. The borrowing base on our revolving credit facility was set at $140 million on March 12, 2009. Under the terms of the determination, our borrowing cost was increased by approximately 100 basis points and the fee on the undrawn portion of the borrowing base was increased by 12.5 basis points. If not extended, our credit facility will mature in January 2011. As of December 31, 2008, we were in compliance with all of the covenants in the credit agreement. All of our lenders are currently funding our borrowing requests.

Impact of Decreasing Natural Gas Prices We account for our gas properties using the full cost method and are required to impair a full cost pool when the net capitalized costs in the pool exceed the discounted future net revenues of the proved reserves associated with the pool. Based upon the lower natural gas prices at December 31, 2008, we have reported a non-cash impairment to our U.S. full cost pool of $20 million, net of income tax. Due to limited initial proved reserve bookings in the Peace River project we also reported a non-cash

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impairment to our Canadian full cost pool of $19 million, net of income tax. If natural gas prices at March 31, 2009 are below those prices that existed at December 31, 2008, GeoMet expects to record a non-cash impairment to the Company s natural gas properties for the quarter then ended.

Trends

Our business is influenced by trends that affect the natural gas industry. In particular, recent declines in natural gas prices and recent economic trends could adversely affect our business, liquidity, results of operations and financial condition.

Our business is increasingly subject to the adverse trends that have taken place in the global capital markets recently. The recent events in the credit and stock markets indicate a high likelihood of a continuation of, and probable further expansion of, the economic weakness in the U.S. economy that began over one year ago. The spillover of deepening fears about our banking system may adversely impact investor confidence in us, our banking relationships, and the liquidity and financial condition of third parties with whom we conduct operations.

We expect to face the continuing challenges of weakness in the U.S. real estate market and increased mortgage delinquencies, investor anxiety over the U.S. economy, rating agency downgrades of various financial issuers, unresolved issues with structured investment vehicles, deleveraging of financial institutions and hedge funds and dislocation in the inter-bank market. If significant, continued volatility, changes in interest rates, defaults, market liquidity, declines in equity prices, and the strengthening or weakening of foreign currencies against the U.S. dollar, individually or in tandem, could have a material adverse effect on our liquidity, results of operations, financial condition or cash flows through realized losses, and impairments.

Although we expect to experience a reduction in the level of our capital spending in 2009, we believe the steps we have taken to date in response to the global slowdown in the natural gas industry will positively impact our ability to follow through with our business strategy without being forced to implement additional significant countermeasures, such as work force layoffs. Other potential steps that could be implemented in light of the current recession, if we deem it necessary, could include selling assets or entering into more joint venture agreements with industry partners to reduce our costs.

The natural gas industry is capital intensive. We make, and anticipate that we will continue to make, substantial capital expenditures in the exploration for, development and acquisition of natural gas reserves. Historically, our capital expenditures have been financed primarily with internally generated cash from operations, proceeds from bank borrowings, and industry joint venture arrangements. The continued availability of these capital sources depends upon a number of variables, including our proved reserves, the volumes of natural gas we produce from existing wells, the prices at which we sell natural gas, our ability to acquire, locate and produce new reserves, and events occurring within the global capital markets. Except for the existing revolving credit facility we have with our bank lenders, we do not currently have any agreements for any future financing and there can be no assurance as to the availability or terms of any such future financing.

Natural Gas Price Trends

Changes in natural gas prices significantly affect our revenues, financial condition, cash flows and borrowing capacity. Markets for natural gas have historically been volatile and we expect this trend to continue. Prices for natural gas typically fluctuate in response to relatively minor changes in supply and demand, market uncertainty, seasonal, political and other factors beyond our control. We are unable to accurately predict the prices we receive for our natural gas. Accordingly, any significant or sustained declines in natural gas prices may materially adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Lower natural gas prices also may reduce the amount of natural gas that we can produce economically. A decline in natural gas prices could have a material adverse effect on the estimated value and estimated quantities of our

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natural gas reserves, our ability to fund our operations and our financial condition, cash flow, results of operations and access to capital. Our capital expenditure budgets are highly dependent on future natural gas prices.

Operational Developments

Pond Creek We connected 26 new infill wells to sales in 2008 giving us a total of 242 productive wells in the Pond Creek field. Net gas sales increased to 13.7 MMcf per day for the year ended December 31, 2008, as compared to 12.3 MMcf per day for the year ended December 31, 2007.

Lasher Initial gas sales commenced on October 28, 2008. We connected a total of 18 wells to sales in 2008. Net gas sales averaged 0.1 MMcf per day for the period of October 28, 2008 through December 31, 2008.

Gurnee We connected 11 new infill wells to sales in 2008 giving us a total of 246 productive wells in the Gurnee field. Net gas sales were unchanged at 6.1 MMcf per day for the years ended December 31, 2008 and 2007.

Garden City In this Chattanooga shale prospect two vertical wells were re-stimulated and a horizontal well drilled in the second quarter was completed in the third quarter. These three wells were connected to sales in the third quarter with net gas sales averaging 0.1 MMcf per day through December 31, 2008. Two vertical test wells drilled in the western portion of the prospect are currently shut-in awaiting the identification of adequate water disposal and connection into a gas sales line. We are still evaluating potential water disposal solutions.

Peace River On December 31, 2008, we commenced gas deliveries from eight wells at Peace River. We own a 50% working interest and operate the project which covers over 50,000 acres of Crown tenure. Four coreholes and twelve production wells have been drilled, targeting the Lower Cretaceous Gething coals. Average coal thickness over the acreage is 52 feet, and the average gas content is 400 cubic feet per ton.

Property Conveyance and Dispute

We had previously entered into an agreement to sell our interests in a property, subject to a preferential right to purchase held by another party, which the other party subsequently exercised. A dispute arose as to whether the preferential right to purchase applied to all the interests we owned in this property or just the working interests. We filed a declaratory judgment action asserting that the preferential right to purchase applied only to the working interests, and that we were entitled to retain all remaining interests we owned in the property. Following a partial agreement with the other party, we assigned all our remaining interests in the property to that party, effective July 1, 2008. On October 17, 2008, the 116th Judicial District Court of Dallas issued an order requiring us to pay $575,000 to the other party in final settlement of the issue. We have subsequently reached a settlement with the other party in the amount of $475,000, which has been accrued as a liability as of December 31, 2008. The proved reserves conveyed represented less than 1% of our total proved reserves and the related production was approximately 900 Mcf per day.

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 GAAP. 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

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elsewhere in this annual report. We believe the following critical accounting policies involve significant judgments, estimates, and a high degree of uncertainty 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, natural gas 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 and MacNaughton, 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 as prescribed by the United States Securities and Exchange Commission (SEC). 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 units-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. Subsequent proved reserve estimates materially different from those reported would change the depletion expense recognized during the future reporting period. No gains or losses are recognized upon the sale or disposition of gas properties unless the sale or disposition represents a significant quantity of gas reserves, which would have a significant impact on the depreciation, depletion and amortization rate.

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

The ceiling limitation test is calculated using natural gas prices in effect as of the balance sheet date and adjusted for basis or location differential, held constant over the life of the reserves. In addition, subsequent to the adoption of SFAS No. 143, Accounting for Asset Retirement Obligations (SFAS 143), the future cash outflows associated with settling asset retirement obligations are not included in the computation of the discounted present value of future net revenues for the purposes of the ceiling limitation test calculation.

At December 31, 2008, the carrying value of the Company s gas properties in the U.S. exceeded the full cost ceiling limitation by $19,959,547, net of income tax of $12,087,937, based upon a natural gas price of

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approximately $5.84 per Mcf in effect at that date. A decline in prices received for gas sales or an increase in operating costs or reductions in estimated economically recoverable quantities could result in the recognition of an impairment of our gas properties in a future period. In the year ended December 31, 2008, we recognized an impairment of our gas properties of $19,959,547, net of income tax of $12,087,937.

At December 31, 2008, the carrying value of the Company s gas properties in Canada exceeded the full cost ceiling limitation by $18,686,273 (no income tax effect as Canadian income taxes are fully valued), based upon a natural gas price of approximately $5.20 per Mcf in effect at that date. A decline in prices received for gas sales or an increase in operating costs or reductions in estimated economically recoverable quantities could result in the recognition of an impairment of our gas properties in a future period. In the year ended December 31, 2008, we recognized an impairment of our gas properties of $18,686,273.

If natural gas prices at March 31, 2009 are below those prices that existed at December 31, 2008, GeoMet expects to record a non-cash impairment to the Company s natural gas properties for the quarter then ended.

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 of proved reserves together with overhead and 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 impairment to unevaluated properties is transferred to the amortization base.

Asset Retirement Liability We adopted SFAS 143*,* effective January 1, 2003. It establishes accounting and reporting standards for retirement obligations associated with tangible long-lived assets that result from the legal obligation to plug, abandon and dismantle existing wells and facilities that we have acquired, constructed or developed. It requires that the fair value of the liability for asset retirement obligations be recognized in the period in which it is incurred. Upon initial recognition of the asset retirement liability, the asset retirement cost is capitalized by increasing the carrying amount of the long-lived asset by the same amount as the liability. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset.

Income Taxes We record our income taxes using an asset and liability approach in accordance with the provisions of the SFAS No. 109, *Accounting for Income Taxes* (SFAS 109) as clarified by FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109* (FIN 48). 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 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 (NOL s).

The Company adopted the provisions of FIN 48 on January 1, 2007. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an entity s financial statements in accordance with SFAS No. 109,

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Accounting for Income Taxes , and prescribes a consistent threshold and measurement attribute for financial statement recognition and disclosure of tax positions taken, or expected to be taken, on a tax return. The adoption of this pronouncement did not have a significant impact on the Company s consolidated financial statements.

Revenue Recognition and Gas Balancing. We derive revenue primarily from the sale of produced natural gas. We use the sales method of accounting for the recognition of gas revenue whereby revenues, net of royalties, are recognized as the production is sold to purchaser. The amount of gas sold may differ from the amount to which the Company is entitled based on its working interest or net revenue interest in the properties. We typically do not have any significant producer gas imbalance positions because we own 100% working interest in the majority of our properties. A ready market for natural gas allows us to 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 nominations and net revenue interests. Pipeline imbalances occur when our production delivered into the pipeline varies from the gas we nominated for sale. Pipeline imbalances are settled with cash approximately thirty days from date of production and are recorded as a reduction of revenue or increase of revenue depending upon whether we are over-delivered or under-delivered.

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 during which payments are received from the purchaser.

Derivative Instruments and Hedging Activities. Our hedging activities consist of derivative instruments entered into to hedge against changes in natural gas prices and changes in interest rates related to outstanding debt under our credit facility primarily through the use of fixed price swap agreements, basis swap agreements, three-way collars, and traditional collars. Consistent with our hedging policy, we entered into a series of derivative instruments to hedge a significant portion of our expected natural gas production through 2009 and 2010. We also entered into interest rate swap agreements to hedge interest rates associated with a portion of our variable rate debt through 2010. Typically, these derivative instruments require payments to (receipts from) counterparties based on specific indices as required by the derivative agreements. These transactions are recorded in our financial statements in accordance with SFAS l33. Although not risk free, we believe this policy will reduce our exposure to natural gas price fluctuations and changes in interest rates and thereby achieve a more predictable cash flow. As a result, our derivative instruments are cash flow hedge transactions in which we are hedging the variability of cash flow related to a forecasted transaction. We do not enter into derivative instruments for trading or other speculative purposes.

In accordance with SFAS 133, as amended, all our derivative instruments are recorded on the balance sheet at fair market value and changes in the fair market value of the derivatives are recorded each period in current earnings for the natural gas derivatives or other comprehensive income (loss) for our interest rate swaps. The natural gas derivatives have not been designated as hedge transactions while the interest rate swaps qualify and have been designated as cash flow hedges in accordance with SFAS 133.

At the inception of a derivative contract, we may designate the derivative as a cash flow hedge. For all derivatives designated as cash flow hedges, we document the relationship between the derivative instrument and the hedged items as well as the risk management objective for entering into the derivative instrument. To be designated as a cash flow hedge transaction, the relationship between the derivative and hedge items must be highly effective in achieving the offset of changes in cash flows attributable to the risk both at the inception of the derivative and on an ongoing basis.

Stock-Based Compensation We follow the fair value recognition provisions of SFAS No. 123(R), *Share-Based Payment* (SFAS 123(R)), using the prospective transition method. The application of SFAS 123(R) requires the use of an option pricing model, such as 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

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assumptions could be highly uncertain. For share-based awards outstanding prior to the adoption of SFAS 123(R), we will continue using the accounting principles originally applied to those awards before adoption. Therefore, we do not recognize any equity compensation cost on these prior awards in the future unless such awards are modified, repurchased or cancelled.

Fair Value Measurement In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements (SFAS 157). SFAS 157 is effective for fiscal years beginning after November 15, 2007. Effective January 1, 2008, we adopted SFAS 157, which provides a framework for measuring fair value under GAAP. SFAS 157 defines fair value as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. SFAS 157 also establishes a fair value hierarchy that requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The standard describes three levels of inputs that may be used to measure fair value. Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 2 inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly, such as quoted prices for similar assets or liabilities; quoted prices in markets that are not active; or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities. Level 3 inputs are derived from unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities. See disclosure related to the implementation of SFAS 157 in Note 6 Derivative Instruments and Hedging Activities. The FASB has also issued Staff Position FAS 157-2 (FSP 157-2), which delays the effective date of SFAS 157 for nonfinancial assets and liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until fiscal years beginning after November 15, 2008. We have elected to defer the application of SFAS 157 thereof to nonfinancial assets and liabilities in accordance with FSP 157-2. Non-recurring nonfinancial assets and nonfinancial liabilities for which the Company has not applied the provisions of SFAS 157 include those measured at fair value in goodwill impairment testing, asset retirement obligations initially measured at fair value, and those initially measured at fair value in a business combination. On October 10, 2008, the FASB issued Staff Position No. FAS 157-3 (FSP 157-3). FSP 157-3 clarifies the application of SFAS 157 in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. On January 1, 2009, we will adopt SFAS 157 as it relates to nonfinancial assets and liabilities, including nonfinancial assets and liabilities measured at fair value in a business combination; impaired property, plant and equipment; goodwill; and initial recognition of asset retirement obligations. There has been no significant impact to our consolidated financial statements related to the implementation of SFAS 157 for our existing non-financial assets and liabilities.

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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, 2008, 2007 and 2006. This table should be read with the discussion of the results of operations for the periods presented below.

	Year Ended December 31,		
	2008	2007	2006
Gas sales	$ 68,314	$ 49,694	$ 44,806
Lease operating expenses	$ 14,757	$ 13,981	$ 11,579
Compression and transportation expenses	4,498	5,209	4,499
Production taxes	2,137	1,164	1,037
Total production expenses	$ 21,392	$ 20,354	$ 17,115
Net sales volumes (Consolidated) (MMcf)	7,453	7,125	6,228
Pond Creek field (MMcf)	5,003	4,494	3,844
Gurnee field (MMcf)	2,241	2,235	1,950
Per Mcf data ($/Mcf):			
Average natural gas sales price (Consolidated)	$ 9.17	$ 6.97	$ 7.19
Pond Creek field	$ 9.17	$ 6.96	$ 7.26
Gurnee field	$ 9.15	$ 6.94	$ 7.05
Average natural gas sales price realized (Consolidated)(1)	$ 9.10	$ 7.52	$ 7.37
Lease operating expenses (Consolidated)	$ 1.98	$ 1.96	$ 1.86
Pond Creek field	$ 1.54	$ 1.60	$ 1.54
Gurnee field	$ 2.98	$ 3.05	$ 2.90
Compression and transportation expenses (Consolidated)	$ 0.60	$ 0.73	$ 0.72
Pond Creek field	$ 0.68	$ 0.92	$ 0.98
Gurnee field	$ 0.49	$ 0.47	$ 0.38
Production taxes (Consolidated)	$ 0.29	$ 0.17	$ 0.17
Pond Creek field	$ 0.15	$ 0.01	$ 0.02
Gurnee field	$ 0.55	$ 0.41	$ 0.41
Total production expenses (Consolidated)	$ 2.87	$ 2.86	$ 2.75
Pond Creek field	$ 2.37	$ 2.53	$ 2.54
Gurnee field	$ 4.02	$ 3.93	$ 3.68
Depletion (Consolidated)	$ 1.35	$ 1.24	$ 1.26

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

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Results of Operations

Year Ended December 31, 2008 compared with Year Ended December 31, 2007

The following are selected items derived from our Consolidated Statement of Operations and their percentage changes from the comparable period are presented below.

	Year Ended December 31,		
	2008	2007	Change
	(in thousands)		
Gas sales	$ 68,314	$ 49,694	37%
Lease operating expenses	$ 14,757	$ 13,981	6%
Compression expense	$ 3,054	$ 2,557	19%
Transportation expense	$ 1,444	$ 2,652	-46%
Production taxes	$ 2,137	$ 1,164	84%
Depreciation, depletion and amortization	$ 10,589	$ 9,092	16%
Impairment of gas properties	$ 50,734	$	NM
General and administrative	$ 9,368	$ 9,294	1%
Realized losses (gains) on derivative contracts	$ 500	$ (3,895)	NM
Unrealized (gains) losses from the change in market value of open derivative contracts	$ (4,993)	$ 3,007	NM
Interest expense, net of amounts capitalized	$ (4,783)	$ (5,130)	-7%
Income tax (benefit) expense	$ (712)	$ 2,987	NM
Discontinued operations	$	$ 174	NM

NM-Not Meaningful

Gas sales. Gas sales increased by $18.6 million, or 37%, to $68.3 million compared to the prior year. The increase in gas sales was a result of both increased gas prices and production. Production increased 5% and average gas prices, excluding hedging transactions, increased 32%. The $18.6 million increase in gas sales consisted of a $2.3 million increase in production and a $16.3 million increase in average prices. The increase in production was principally attributable to the continued development activities at our Pond Creek and Gurnee fields.

Lease operating expenses. Lease operating expenses increased by $0.8 million, or 6%, to $14.8 million compared to the prior year. The $0.8 million increase in lease operating expenses consisted of $0.6 million increase in production and $0.2 million increase in costs.

Compression expense. Compression expense increased by $0.5 million, or 19%, to $3.1 million compared to the same period in the prior year. The increase in compression expense consisted of a $0.1 million increase in production and a $0.4 million increase in costs. The $0.4 million increase in costs was primarily due to an increase in repair and maintenance expenses for the compressors in our Pond Creek field.

Transportation expense. Transportation expense decreased by $1.2 million, or 46%, to $1.4 million compared to the prior year period. The decrease was primarily due to lower transportation expenses resulting from the commencement of transportation on our own system from the Pond Creek field and the temporary release of a portion of our firm capacity commitments related to our Pond Creek field.

Production taxes. Production taxes increased by $1.0 million, or 84%, to $2.1 million compared to the prior year period. The increase in production taxes was due to the phase-in of state taxes on production of natural gas in our Pond Creek field, higher gas prices and increased production.

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Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $1.5 million, or 16%, to $10.6 million compared to the prior year period. The depreciation, depletion and amortization increase consisted of a $0.4 million increase in production and a $1.1 million increase in the depletion rate.

Impairment of gas properties. At December 31, 2008, the carrying value of the Company s oil and gas properties exceeded the full cost ceiling limitation by approximately $50.7 million. For the year ended December 31, 2007, no such write-down was recorded.

General and administrative. General and administrative expenses increased by $0.1 million, or 1%, to $9.4 million compared to the prior year period. The primary driver for the increased general and administrative expenses was increased office expense, share based awards and investor relation expense, offset by a decrease in employee bonuses.

Realized losses (gains) on derivative contracts. Realized losses on derivative contracts were $0.5 million in the current year period as compared to $3.9 million of realized gains in the prior year 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 natural gas prices or the derivative index price exceeds the derivative ceiling price. Conversely, realized gains occur when natural gas prices go below the derivative floor price.

Unrealized (gains) losses from the change in market value of open derivative contracts. Unrealized gains on open derivative contracts were $5.0 million in the current year period as compared to a $3.0 million in unrealized losses in the prior year period. Unrealized losses and gains are non-cash transactions that occur when the corresponding natural gas derivative contract asset or liability is marked to market at the end of each reporting period.

Interest expense (net of amounts capitalized). Interest expense (net of amounts capitalized) decreased by $0.3 million, or 7%, to $4.8 million compared to the prior year period. Gross interest expense for the period was $5.1 million net of $0.3 million capitalized. Gross interest expense decreased 11% from the prior year period due to lower interest rates, while capitalized interest decreased 48% from the prior year period due to the deferral of certain capital projects.

Income tax benefit. Income tax benefit was $0.7 million in the current year as compared to an expense of $3.0 million in the prior year period. The effective tax rate for the 2008 was 3.1% as compared to 37.4% for 2007. The decrease in the effective tax rate was due to the full valuation of the deferred income tax benefit of $6.6 million related to our Canadian impairment of gas properties recorded in 2008.

Discontinued operations. In September of 2007, we discontinued the third party marketing business and second reportable segment which had been created in connection with the consolidation of Shamrock Energy LLC, a variable interest entity under FIN 46 (R) on August 1, 2006. The consolidation of the variable interest entity had no impact on our net income (loss) due to the 100% minority interest to Shamrock Energy LLC. On January 1, 2007, we acquired Shamrock Energy LLC as a wholly owned subsidiary and the consolidation of this wholly owned subsidiary had an insignificant impact on our net income (loss). As a result of exiting our third party marketing business, we are treating these activities as a discontinued operation for all the periods presented.

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Results of Operations

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

	Year Ended December 31, 2007	2006	Change
		(In thousands)	
Gas sales	$ 49,694	$ 44,806	11%
Lease operating expenses	$ 13,981	$ 11,579	21%
Compression and transportation expenses	$ 5,209	$ 4,499	16%
Production taxes	$ 1,164	$ 1,037	12%
Depreciation, depletion and amortization	$ 9,092	$ 7,876	15%
General and administrative	$ 9,294	$ 6,553	42%
Realized gains on derivative contracts	$ 3,895	$ 1,118	NM
Unrealized (gains) losses from the change in market value of open derivative contracts	$ 3,007	$ (16,877)	NM
Interest expense (net of amounts capitalized)	$ 5,130	$ 3,130	64%
Income tax expense	$ 2,987	$ 10,866	NM%
Discontinued operations	$ 174	$	NM%

NM-Not Meaningful

Gas sales. Gas sales increased by $4.9 million, or 11%, to $49.7 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 14% while average gas prices, excluding hedging transactions, decreased 3%. The $4.9 million increase in gas sales consisted of a $6.5 million increase in production and a $1.6 million decrease in average prices. The increase in production was principally attributable to our Gurnee and Pond Creek development activities.

Lease operating expenses. Lease operating expenses increased by $2.4 million, or 21% to $14.0 million. The $2.4 million increase in lease operating expenses consisted of $1.7 million increase in production and $0.7 million increase in costs. The increase in costs is related to an increase in well service activities from the prior year period.

Compression and transportation expenses. Compression and transportation expenses increased by $0.7 million, or 16%, to $5.2 million ($2.6 million each for both compression and transportation). The $0.7 million increase was comprised of a $0.5 million increase in compression expenses due to increased production and a $0.2 million increase in transportation expenses due to increased production offset by a decrease in the actual per Mcf transportation expenses due to the certain gas transported on our own system in 2007.

Production taxes. Production taxes increased by $0.127 million, or 12%, to $1.164 million. The production taxes increase of $0.127 million was primarily due to increased production, partially offset by lower average gas prices.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $1.2 million, or 15%, to $9.1 million. The depreciation, depletion and amortization increase of $1.2 million resulted from the increase in production. There were no significant changes in the depletion rate in 2007.

General and administrative. General and administrative expenses increased by $2.7 million, or 42%, to $9.3 million. The increase in general and administrative expenses was a result of increases in employee expenses (15%), professional services (94%), director and investor relations expenses (139%), insurance expense (74%) and office expenses and business taxes (6%). 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 on derivative contracts. Realized gains on derivative contracts increased by $2.8 million to $3.9 million compared to a gain of $1.1 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 natural gas prices or the derivative index price exceeds the derivative ceiling price. Conversely, realized gains occur when natural 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 $3.0 million loss as compared to a $16.9 million gain 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 $3.0 million loss was a result of increased future natural gas prices.

Interest expense (net of amounts capitalized). Interest expense (net of amounts capitalized) increased by $2 million, or 64%, to $5.1 million. The increase was primarily due to higher outstanding debt and higher interest rates. Capitalized interest totaled $0.6 million and $1.0 for the years ended December 31, 2007 and 2006, respectively.

Income tax expense. Income tax expense decreased by $7.9 million to $3.0 million. The decrease in income tax expense for the period was due to decreased pretax income compared to the prior period. In addition, the effective tax rate decreased for the year to 37% from 39% in the comparable prior period. The principal driver for the difference in the effective tax rate was due to lower state income taxes resulting from state apportionment factor shifting.

Discontinued operations. In September of 2007, we discontinued the third party marketing business and second reportable segment which had been created in connection with the consolidation of Shamrock Energy LLC, a variable interest entity under FIN 46 (R) on August 1, 2006. The consolidation of the variable interest entity had no impact on our net income (loss) due to the 100% minority interest to Shamrock Energy LLC. On January 1, 2007, we acquired Shamrock Energy LLC as a wholly owned subsidiary and the consolidation of this wholly owned subsidiary had an insignificant impact on our net income (loss). As a result of exiting our third party marketing business, we are treating these activities as a discontinued operation for all the periods presented.

Liquidity and Capital Resources

Cash Flows and Liquidity

Cash flows from operations for the year ended December 31, 2008 and 2007 were $33.0 million and $17.5 million, respectively. Cash flow provided by operations for the year ended December 31, 2008 of $33.0 million combined together with $20.5 million (net) borrowed from our revolving credit facility were sufficient to fund our cash basis capital expenditures of $52.8 million.

As of December 31, 2008, we had a working capital deficit of approximately $1.4 million, a decrease of $0.7 million from the working capital deficit of $2.1 million at December 31, 2007. At December 31, 2008, we had adequate cash flows from operating activities and credit availability to fund our working capital deficits.

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The following table is a summary of our capital expenditures on an accrual basis by category:

	Year Ended December 31,		
	2008	2007	2006
	(In thousands)		
Capital expenditures:			
Leasehold acquisition	$ 3,669	$ 7,333	$ 8,975
Exploration	405	2,999	7,626
Development	48,404	44,831	62,211
Other items (primarily capitalized overhead and interest)	5,294	4,649	2,781
Total capital expenditures	$ 57,772	$ 59,812	$ 81,593

Our capital expenditure budget for 2009 will be funded from our estimated operating cash flows. If our cash flows are not sufficient to fund all of our estimated capital expenditures, we may reduce our capital budget. The amount and timing of our expenditures are subject to change based upon market conditions, results of expenditures and other factors. We routinely adjust our capital expenditure budget in response to changes in natural gas prices, drilling and acquisition costs, cash flow, drilling results and borrowing base redeterminations under our revolving credit facility. Based on current gas price projections, we expect capital expenditures to be less than the $24.1 million capital budget we previously announced.

The development of coalbed methane 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, the transportation alternatives, and the timing and volume of initial and subsequent natural gas production volumes.

Based upon current expectations, we believe that we will have adequate resources from cash flows provided by operations and from proceeds from our revolving credit facility borrowings to fund our 2008 capital expenditures and other working capital needs.

Currently, there is an unprecedented uncertainty in the financial markets. The uncertainty in the market brings additional potential risks to us. The risks include less availability and higher costs of additional credit, potential counterparty defaults, and further commercial bank failures. Although the financial institutions in our bank group appear to be strong, there are some that have been and could be considered take-over candidates. Although we have no indication that any such transactions would impact our current credit facility, the possibility does exist. Financial market disruptions may impact our ability to collect trade receivables. We constantly monitor the credit worthiness of our customers. We believe that our current group of customers are sound and represent no abnormal business risk.

If natural gas prices decrease from their current levels for an extended period, our ability to finance our planned capital expenditures could be affected negatively, consistent with our intention to keep our capital expenditures in line with our estimated operating cash flows, further reduction in spending may be necessary. 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.

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Natural Gas Price Risk and Related Hedging Activities.

We are exposed to natural gas price risk associated with downward movements in natural gas prices. Natural gas prices have experienced volatility in recent years in response to changes in the supply and demand for natural gas and market uncertainty. The markets and prices for natural gas depend upon factors beyond our control and changes in these prices could adversely affect our revenue and cash flows. These factors include demand for natural gas, which fluctuates with changes in market and economic conditions and other factors, including the impact of seasonality and weather, general economic conditions, the level of domestic and offshore natural gas production and consumption, the availability of imported natural gas, actions taken by foreign oil and gas producing nations, the availability of local, intrastate and interstate transportation systems, the availability and marketing of competitive fuels, the impact of energy conservation efforts, technological advances affecting energy consumption and the extent of governmental regulation and taxation.

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 using derivative instruments in the form of three-way collars, traditional collars and swaps. 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 and at times hedge forward for periods of more than two years. We generally limit the amount of these hedges during any period to no more than 50% to 60% of the then expected gas production for such future periods. 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 (a sold ceiling) and a minimum floor (a bought 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 (through a sold floor) to a predetermined amount, generally between $2.00 and $3.00 per MMBtu. We have accounted for these transactions using the mark-to-market accounting method. Generally, we incur accounting losses during periods where prices are rising and gains during periods where prices are falling which may cause significant fluctuations in our consolidated statement of operations.

We believe that the use of derivative instruments does not expose us to material risk. However, the use of derivative instruments may materially affect our financial position and results of operations as a result of changes in the estimated market value of our natural gas derivatives. Nevertheless, we believe that use of these instruments will not have a material adverse effect on our cash flows.

The following (gains) losses on our hedging instruments included in the consolidated statements of operations are as follows:

	2008	2007	2006
Realized losses (gains) on derivative contracts	$ 500,452	$ (3,895,138)	$ (1,118,043)
Unrealized (gains) losses on derivative contracts	(4,993,238)	3,006,916	(16,877,225)
Total (gains) losses	$ (4,492,786)	$ (888,222)	$ (17,995,268)

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Commodity Price Risk and Related Hedging Activities.

At December 31, 2008, we had the following natural gas collar positions:

Period	Volume (MMBtu)	Sold Ceiling	Bought Floor	Sold Floor	Fair Value
January through March 2009	540,000	$ 11.00	$ 8.50	$ 6.25	$ 1,138,548
January through March 2009	540,000	$ 11.00	$ 8.84	$ 6.00	$ 1,403,907
April through October 2009	1,284,000	$ 10.00	$ 7.50	$ 5.25	$ 1,615,808
April through October 2009	1,284,000	$ 10.00	$ 8.50	$ 6.50	$ 1,864,114
November 2009 through March 2010	906,000	$ 11.20	$ 9.50	$ 7.00	$ 1,297,652
					$ 7,320,029

Interest Rate Risks and Related Hedging Activities

When we enter into an interest rate swap, we may designate the derivative as a cash flow hedge, at which time we prepare the documentation required under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS l33). Hedges of our interest rate are designated as cash flow hedges based on whether the interest on the underlying debt is converted to a fixed interest rate. Changes in derivative fair values that are designated as cash flow hedges are deferred as other comprehensive income (loss) or loss to the extent that they are effective and then recognized in earnings when the hedged transactions occur.

We use fixed rate swaps to limit our exposure to fluctuations in interest rates with the objective of realizing a fixed cash flow stream from these activities. At December 31, 2008, we had the following interest rate swaps:

Description	Effective date	Designated maturity date	Fixed rate(1)	Notional amount	Fair Value
Floating-to-fixed swap	12/14/2007	12/14/2010	3.86%	$ 15,000,000	$ (608,561)
Floating-to-fixed swap	1/3/2008	1/4/2010	3.95%	$ 10,000,000	(243,520)
Floating-to-fixed swap	3/25/2008	3/25/2010	2.38%	$ 10,000,000	(131,102)
Floating-to-fixed swap	5/13/2008	5/13/2010	3.07%	$ 5,000,000	(106,209)
					$ (1,089,392)

(1) The floating rate paid by the counterparty is the British Bankers Association LIBOR rate.
For the year ended December 31, 2008, we recognized no ineffective portion of our cash flow hedges.

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. We do not have rights to collateral from our counterparties, nor do we have rights of offset against borrowings under our credit agreement.

The application of SFAS 157 currently applies to our derivative instruments. Under the provisions of SFAS 157, we estimate the fair value of our natural gas hedges and interest rate swaps using the income approach. The income approach uses valuation techniques that convert future cash flows to a single discounted value. SFAS 157 clarifies that a fair value measurement for an asset or liability reflects its nonperformance risk, the risk that the obligation will not be fulfilled. Because nonperformance risk includes our counterparties and our credit risk, we have considered the effect of our credit risk on the fair value of the liabilities stated below. This consideration involved discounting our counterparties and our liabilities based on the difference between the S&P credit rating of a comparable company to ours and the 13-week Treasury bill rate, both at December 31, 2008. The following is a description of the valuation methodologies used for our derivative instruments measured at fair value:

Natural Gas Hedges In order to estimate the fair value of our natural gas hedge positions, a forward price curve and volatility estimates were compiled from sources that include NYMEX settlements and

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observed trading activity in the Over-the-Counter (OTC) markets. Pricing estimates for the theoretical market value of hedge positions were developed using analytical models accepted and employed by a broad cross-section of industry participants. To extrapolate future cash flows, discount factors incorporating our counterparties and our credit standing are used to discount future cash flows.

Interest Rate Swaps In order to estimate the fair value of our interest rate swaps, we use a yield curve based on Money Market rates and Interest Rate swaps, extrapolate a forecast of future interest rates, estimate each future cash flow, derive discount factors to value the fixed and floating rate cash flows of each swap, and then discount to present value all known (fixed) and forecasted (floating) swap cash flows. Curve building and discounting techniques used to establish the theoretical market value of interest bearing securities are based on readily available Money Market rates and Interest Rate swap market data. To extrapolate future cash flows, discount factors incorporating our counterparties and our credit standing are used to discount future cash flows.

Based on the use of observable market inputs, we have designated these types of instruments as Level 2 for SFAS 157 reporting purposes. The fair value of our derivative instruments at December 31, 2008 and 2007 were as follows:

	2008	2007
Interest rate swap asset	$	$ 10,884
Natural gas hedge asset	7,320,029	2,326,791
Total derivative assets	$ 7,320,029	$ 2,337,675
Interest rate swap liability	$ 1,089,392	$
Natural gas hedge liability		
Total derivative liabilities	$ 1,089,392	$

In June 2006, we entered into a 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 was $180 million at December 31, 2008. As of December 31, 2008, our credit agreement provided for interest to accrue at a rate calculated, at our option, at either the adjusted base rate (which is the greater of the agent s base rate or the federal funds rate plus one half of one percent) or the London Interbank Offered Rate (LIBOR) plus a margin of 1.00% to 2.00%, based on borrowing base usage. Under the terms of the determination, our borrowing cost was increased by approximately 100 basis points and the fee on the undrawn portion of the borrowing base was increased by 12.5 basis points. 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 (adjusted for unrealized (gains) losses on derivative contracts and borrowing availability) 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 revolving 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,

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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, 2008, we were in compliance with all of the covenants in the credit agreement.

At December 31, 2008, we had $116.5 million outstanding under our revolving credit facility. For the year ended December 31, 2008, interest on the borrowings averaged 4.56% per annum. Borrowing availability at December 31, 2008 was $63.5 million.

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, 2008, beginning January 1, 2009 (in thousands):

	2009	2010	2011	2012	2013 and thereafter
Long-term debt and other obligations(1)	$ 112	$ 122	$ 116,633	$ 92	$ 272
Interest expense on revolving credit facility(2)	2,898	2,898	48		
Operating lease obligations	1,455	1,394	1,353	551	634
Interest rate swap contracts	715	374			
Asset retirement obligations	117				4,349
Firm transportation contracts	2,526	2,442	1,907	1,313	9,515
Other operating commitments	200	173			
FIN 48(3)					
Total commitments	$ 8,023	$ 7,403	$ 119,941	$ 1,956	$ 14,770

(1) Maturities based on the June 2006 amended bank credit agreement terms, which extended the maturity date to January 6, 2011.
(2) Assumes an annual rate on a 30-day LIBOR of 0.99% plus the current 1.50% margin for a total interest rate of 2.49%, net of swap recoveries.
(3) As of December 31, 2008, we had a liability for unrecognized tax benefits of approximately $273K. We are unable to reliably estimate the timing and amount of any payments related to this liability because there are currently no outstanding unpaid assessments from any tax authority, and it is likely that assessments would be offset by existing deferred tax attributes as they arise.

Discontinued Operations

As of September 30, 2007, we discontinued the third party marketing business and second reportable segment which had been created in connection with the consolidation of Shamrock Energy LLC, a variable interest entity under FIN 46(R) on August 1, 2006. The consolidation of the variable interest entity had no impact on our net income (loss) due to the 100% minority interest to Shamrock Energy LLC. On January 1, 2007, we acquired Shamrock Energy LLC as a wholly owned subsidiary and the consolidation of this wholly owned subsidiary had an insignificant impact on our net income (loss). As a result, we are treating our third party marketing activities as a discontinued operation for all the periods presented.

The marketing activities of Shamrock Energy LLC have been transitioned to GeoMet, Inc without disruption in the marketing of our gas, and we do not expect to incur significant liabilities or sell any assets in connection with discontinuing this business. As a result, the discontinued operations have an insignificant impact on our cash flows.

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Recent Accounting Pronouncements

In December 2007, the Financial Accounting Standards Board (the FASB) issued Statement of Financial Accounting Standards No. 141R, Business Combinations (Revised 2007) (SFAS 141R), which establishes principles and requirements for how an acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest; recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase; and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS 141R is to be applied prospectively to business combinations for which the acquisition date is on or after the beginning of an entity s fiscal year that begins on or after Dec. 15, 2008. We will evaluate the impact of SFAS 141R on our consolidated financial statements for any potential business combinations subsequent to Jan. 1, 2009.

On February 15, 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB 115 (SFAS 159). This standard permits an entity to measure financial instruments and certain other items at estimated fair value. Most of the provisions of SFAS 159 are elective; however, the amendment to FASB 115, Accounting for Certain Investments in Debt and Equity Securities, applies to all entities that own trading and available-for-sale securities. The fair value option created by SFAS 159 permits an entity to measure eligible items at fair value as of specified election dates. The fair value option (a) may generally be applied instrument by instrument, (b) is irrevocable unless a new election date occurs, and (c) must be applied to the entire instrument and not to only a portion of the instrument. SFAS 159 is effective as of the beginning of the first fiscal year that begins after November 15, 2007. Effective January 1, 2008, we adopted SFAS 159. We did not elect the fair value option for any of our assets or liabilities that did not already require such treatment under other authoritative literature.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements (SFAS 160). SFAS 160 clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. SFAS 160 requires that changes in a parent s ownership interest in a subsidiary be reported as an equity transaction in the consolidated financial statements when it does not result in a change in control of the subsidiary. When a change in a parent s ownership interest results in deconsolidation, a gain or loss should be recognized in the consolidated financial statements. SFAS 160 must be applied prospectively as of January 1, 2009, except for the presentation and disclosure requirements, which are required to be applied retrospectively for all periods presented. The adoption of SFAS 160 did not have a material impact on our results of operations, cash flows or financial positions; however, it could impact future transactions entered into by us.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133 (SFAS 161). This standard changes the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. SFAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We are currently assessing the impact of SFAS 161 on our disclosures relating to derivative instruments and hedging activities. The statement only provides for enhanced disclosure. Therefore, adoption will have no impact on our financial position or results of operations.

In May 2008, the FASB issued Statement No. 162, The Hierarchy of Generally Accepted Accounting Principles. The new standard is intended to improve financial reporting by identifying a consistent framework, or hierarchy, for selecting accounting principles to be used in preparing financial statements that are presented in conformity with GAAP for nongovernmental entities. Statement 162 establishes that the GAAP hierarchy should be directed to entities because it is the entity (not its auditor) that is responsible for selecting accounting

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principles for financial statements that are presented in conformity with GAAP. Statement 162 is effective 60 days following the SEC s approval of the Public Company Accounting Oversight Board Auditing amendments to AU Section 411, The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles. We do not expect this guidance to have a significant impact on us.

In June 2008, the FASB issued FASB Staff Position No. EITF 03-6-1 Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities (FSP EITF 03-6-1), which addresses whether instruments granted in share-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the net income allocation in computing basic net income per share under the two class method prescribed under SFAS 128, Earnings per Share . FSP 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and, to the extent applicable, must be applied retrospectively by adjusting all prior-period net income per share data to conform to the provisions of the standard. The adoption of FSP EITF 03-6-1 is not expected to have a material effect on the Company s earnings per share calculations.

In December 2008, the SEC released Final Rule, Modernization of Oil and Gas Reporting to revise the existing Regulation S-K and Regulation S-X reporting requirements to align with current industry practices and technological advances. The new disclosure requirements include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. In addition, the new disclosure requirements require a company to (a) disclose its internal control over reserves estimation and report the independence and qualification of its reserves preparer or auditor, (b) file reports when a third party is relied upon to prepare reserves estimates or conducts a reserve audit and (c) report oil and gas reserves using an average price based upon the prior 12-month period rather than period-end prices. The provisions of this final ruling will become effective for disclosures in our Annual Report on Form 10-K for the year ended December 31, 2009.

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

Commodity Risk. Our major commodity price risk exposure is to the prices received for our natural gas production. Realized prices received for our natural gas production are the spot prices applicable to natural gas. Prices received for natural gas are volatile and unpredictable and are beyond our control. At December 31, 2008, a 10% decrease in the prices received for natural gas production would have had an approximate $2.7 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. At December 31, 2008, we had $116.5 million outstanding under our revolving credit facility. For the year ended December 31, 2008, interest on the borrowings averaged 4.56% per annum. Borrowing availability at December 31, 2008 was $63.5 million. All of the debt outstanding under our revolving 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 revolving credit facility at December 31, 2008, a 1% increase in market interest rates would have increased interest expense and negatively impacted our annual cash flows by approximately $0.8 million. $40 million of the outstanding balance was excluded from our market rate analysis due to lack of interest rate exposure based on the interest rate swaps we have in place.

Foreign Currency Exchange Rate Risk. We have operations in Canada 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. The effect of changes in the exchange rate may impact our revenues or expenses, as well as the costs of our proved properties. We continue to monitor the foreign currency exchange rate in Canada and may implement measures to protect against the foreign currency exchange rate risk in the future.

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

GEOMET, INC. AND SUBSIDIARIES

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of GeoMet, Inc.

Houston, TX

We have audited the accompanying consolidated balance sheets of GeoMet, Inc. and subsidiaries (the Company) as of December 31, 2008 and 2007, and the related consolidated statements of operations, stockholders equity and comprehensive income (loss) and cash flows for each of the three years in the period ended December 31, 2008. We also have audited the Company s internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission*. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management s Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on these financial statements and an opinion on the Company s internal control over financial reporting 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 and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of GeoMet, Inc. and subsidiaries as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the criteria established in *Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission*.

As discussed in Note 1 to the consolidated financial statements, the Company adopted Financial Accounting Standards Board Interpretations No. 48, Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109 on January 1, 2007.

/s/ DELOITTE & TOUCHE LLP

Houston, TX

March 12, 2009

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GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2008	December 31, 2007
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 2,096,561	$ 1,540,516
Accounts receivable, net of allowance of $60,848 and $0, respectively.	5,364,456	4,881,397
Inventory	3,339,228	2,355,595
Derivative asset	6,596,360	2,247,248
Other current assets	541,311	484,341
Total current assets	17,937,916	11,509,097
Gas properties utilizing the full cost method of accounting:		
Proved gas properties	447,968,536	370,404,336
Unevaluated gas properties, not subject to amortization	5,017	25,174,764
Other property and equipment	3,429,890	2,536,619
Total property and equipment	451,403,443	398,115,719
Less accumulated depreciation, depletion, amortization and impairment of gas properties	(93,104,323)	(31,886,633)
Property and equipment net	358,299,120	366,229,086
Other noncurrent assets:		
Derivative asset	723,669	90,427
Other	639,648	848,816
Total other noncurrent assets	1,363,317	939,243
TOTAL ASSETS	$ 377,600,353	$ 378,677,426
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Accounts payable	$ 13,384,675	$ 7,536,274
Accrued liabilities	2,623,640	5,087,871
Deferred income taxes	2,426,798	770,675
Derivative liability	714,903	
Asset retirement liability	117,423	74,387
Current portion of long-term debt	111,767	102,586
Total current liabilities	19,379,206	13,571,793
Long-term debt	117,117,955	96,729,722
Asset retirement liability	4,348,938	2,915,855
Other long-term accrued liabilities	105,890	138,471
Derivative liability	374,489	
Deferred income taxes	43,841,950	46,645,879

TOTAL LIABILITIES	185,168,428	160,001,720
Commitments and contingencies (Note 15)		
Stockholders Equity:		
Preferred stock, $0.001 par value authorized 10,000,000, none issued		
Common stock, $0.001 par value authorized 125,000,000 shares; issued and outstanding 39,305,152 and 38,962,359 at December 31, 2008 and December 31, 2007, respectively	39,050	38,962
Treasury stock 10,432 shares and 7,828	(93,811)	(70,452)
Paid-in capital	188,692,242	187,620,936
Accumulated other comprehensive (loss) income	(2,399,992)	2,394,001
Retained earnings	6,422,772	28,909,363
Less notes receivable	(228,336)	(217,104)
Total stockholders equity	192,431,925	218,675,706
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 377,600,353	$ 378,677,426

See accompanying Notes to Consolidated Audited Financial Statements.

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GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

FOR THE YEARS ENDED DECEMBER 31,

	2008	2007	2006
Revenues:			
Gas sales	$ 68,313,948	$ 49,694,489	$ 44,805,876
Operating fees and other	780,267	1,289,575	140,922
Total revenues	69,094,215	50,984,064	44,946,798
Expenses:			
Lease operating expense	14,756,521	13,981,093	11,579,112
Compression and transportation expense	4,498,243	5,209,206	4,498,850
Production taxes	2,136,963	1,164,159	1,037,401
Depreciation, depletion and amortization	10,589,490	9,091,610	7,876,212
Impairment of gas properties	50,733,757		
General and administrative	9,368,279	9,294,279	6,682,032
Realized losses (gains) on derivative contracts	500,452	(3,895,138)	(1,118,043)
Unrealized (gains) losses from the change in market value of open derivative contracts	(4,993,238)	3,006,916	(16,877,225)
Total operating expenses	87,590,467	37,852,125	13,678,339
Operating (loss) income from continuing operations	(18,496,252)	13,131,939	31,268,459
Other income (expense):			
Interest income	43,876	39,341	33,149
Interest expense (net of amounts capitalized)	(4,783,076)	(5,129,847)	(3,130,005)
Other	36,961	(58,589)	(9,773)
Total other income (expense):	(4,702,239)	(5,149,095)	(3,106,629)
(Loss) income before income taxes, minority interest & discontinued operations	(23,198,491)	7,982,844	28,161,830
Income tax (benefit) expense	(711,900)	2,987,407	10,865,614
(Loss) income before minority interest & discontinued operations	(22,486,591)	4,995,437	17,296,216
Discontinued operations:			
Discontinued operations, net of income tax		173,782	22,535
Minority interest, net of income tax			(22,535)
Income from discontinued operations		173,782	
Net (loss) income	$ (22,486,591)	$ 5,169,219	$ 17,296,216
(Loss) earnings per share:			
(Loss) income from continuing operations			
Basic	$ (0.58)	$ 0.13	$ 0.49
Diluted	$ (0.58)	$ 0.13	$ 0.48

Discontinued operations						
Basic	$		$		$	
Diluted	$		$		$	
Net (loss) income per common share						
Basic	$	(0.58)	$	0.13	$	0.49
Diluted	$	(0.58)	$	0.13	$	0.48
Weighted average number of common shares:						
Basic		38,856,841		38,822,671		35,018,122
Diluted		38,856,841		39,699,694		35,964,301

See accompanying Notes to Consolidated Audited Financial Statements.

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GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

AND COMPREHENSIVE INCOME (LOSS)

	Common Stock Par Value $0.001 (shares outstanding)	Common Stock Par Value $0.001	Treasury Stock	Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Notes Receivable	Total Stockholders Equity
Balance at January 1, 2006	29,974,664	$ 29,975	$	$ 106,408,915	$ 56,310	$ 6,443,928	$ (17,516,852)	$ 95,422,276
Sale of common stock, 144A and IPO	8,067,023	8,067		81,479,741				81,487,808
Exercise of stock options	637,026	637		1,122,255				1,122,892
Offering costs				(2,996,890)				(2,996,890)
Stock-based compensation				1,328,784				1,328,784
Payments on notes receivable							17,184,357	17,184,357
Accrued interest on notes receivable				(489,953)			(97,786)	(587,739)
Comprehensive income:								
Net income						17,296,216		17,296,216
Foreign currency translation adjustment, net of income tax of $0					(250,198)			(250,198)
Total comprehensive income								17,046,018
Balance at December 31, 2006	38,678,713	$ 38,679	$	$ 186,852,852	$ (193,888)	$ 23,740,144	$ (430,281)	$ 210,007,506
Restricted stock awards	178,081	178		(178)				
Exercise of stock options	105,565	105		224,660				224,765
Stock-based compensation				526,575				526,575
Purchase of treasury stock (7,828 shares)			(70,452)				66,070	(4,382)
Payments on notes receivable							164,134	164,134
Accrued interest on notes receivable				17,027			(17,027)	
Comprehensive income:								
Net income						5,169,219		5,169,219
Gain on interest rate swap, net of income tax of $0					10,884			10,884
Foreign currency translation adjustment, net of income tax of $0					2,577,005			2,577,005
Total comprehensive income								7,757,108
Balance at December 31, 2007	38,962,359	$ 38,962	$ (70,452)	$ 187,620,936	$ 2,394,001	$ 28,909,363	$ (217,104)	$ 218,675,706
Exercise of stock options	68,605	69		118,377				118,446
Stock-based compensation	18,720	19		941,697				941,716
Purchase of treasury stock (2,604 shares)			(23,359)					(23,359)
Accrued interest on notes receivable				11,232			(11,232)	
Comprehensive loss:								
Net loss						(22,486,591)		(22,486,591)
					(689,370)			(689,370)

Loss on interest rate swap, net of income taxes of $410,906								
Foreign currency translation adjustment, net of income taxes of $0					(4,104,623)			(4,104,623)
Total comprehensive income								(27,280,584)
Balance at December 31, 2008	39,049,684	$ 39,050	$ (93,811)	$ 188,692,242	$ (2,399,992)	$ 6,422,772	$ (228,336)	$ 192,431,925

See accompanying Notes to Consolidated Audited Financial Statements.

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GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2008	**2007**	**2006**
Cash flows provided by operating activities:			
Net (loss) income	$ (22,486,591)	$ 5,169,219	$ 17,296,216
Adjustments to reconcile net (loss) income to net cash flows provided by operating activities:			
Depreciation, depletion and amortization	10,589,490	9,265,167	8,033,265
Impairment of gas properties	50,733,757		
Amortization of debt issuance costs	172,935	146,280	136,394
Deferred income tax (benefit) expense	(736,900)	3,066,333	10,737,531
Unrealized (gains) losses from the change in market value of open derivative contracts (including premium amortization)	(4,993,238)	3,006,916	(16,877,225)
Stock-based compensation	566,416	311,482	317,298
(Gain) loss on sale of other assets	41,521	(64,834)	(7,861)
Accretion expense	365,103	209,850	157,342
Allowance for doubtful accounts	60,848		
Changes in operating assets and liabilities:			
Accounts receivable	(595,689)	6,111,907	(5,323,795)
Other current assets	(1,058,790)	(2,348,588)	(233,821)
Accounts payable	3,130,996	244,892	5,836,535
Accrued income tax payable		(6,709,656)	
Other accrued liabilities	(2,831,465)	(922,101)	1,400,201
Net cash provided by operating activities	32,958,393	17,486,867	21,472,080
Cash flows used in investing activities:			
Capital expenditures (including lease acquisitions)	(52,797,122)	(54,026,382)	(79,060,608)
Proceeds from sale of assets	43,084	126,285	204,917
Other assets	35,161	67,927	186,553
Net cash used in investing activities	(52,718,877)	(53,832,170)	(78,669,138)
Cash flows provided by financing activities:			
Debt issuance costs		(100,000)	(341,730)
Proceeds from exercise of stock options	118,446	224,765	1,122,892
Equity offering costs			(2,280,447)
Proceeds from sales of common stock			81,487,808
Proceeds from revolver borrowings	115,000,000	83,000,000	125,000,000
Payments on revolver	(94,500,000)	(47,000,000)	(164,000,000)
Treasury stock	(23,359)	(4,382)	
Proceeds from notes receivable and accrued interest		164,134	17,184,357
Payments on other debt	(102,586)	(93,979)	(86,563)
Net cash provided by financing activities	20,492,501	36,190,538	58,086,317
Effect of exchange rate changes on cash and cash equivalents	(175,972)	280,805	(90,589)
Increase (decrease) in cash and cash equivalents	556,045	126,040	798,670
Cash and cash equivalents at beginning of year	1,540,516	1,414,476	615,806

Cash and cash equivalents at end of year	$ 2,096,561	$ 1,540,516	$ 1,414,476
Supplemental disclosure of cash flow information:			
Cash paid during the year for:			
Interest expense	$ 4,891,199	$ 5,672,771	$ 3,858,895
Income taxes	$ 36,192	$ 25,000	$ 55,000
Significant noncash investing and financing activities:			
Accrued capital expenditures	$ 5,556,897	$ 1,994,186	$ 2,176,475

See accompanying Notes to Consolidated Audited Financial Statements.

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GEOMET, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS

Note 1 Organization and Our Business

GeoMet, Inc. (GeoMet, Company, we, or our) (formerly GeoMet Resources, Inc.) was incorporated under the laws of the state of Delaware on November 9, 2000. We are an independent natural gas producer primarily involved in the exploration, development and production of natural gas from coal seams (coal bed methane) and non-conventional shallow gas. Our principal operations and producing properties are located in Alabama, West Virginia, Virginia and Canada.

Note 2 Summary of Significant Accounting Policies

Principles of Consolidation The accompanying Consolidated Financial Statements are presented in conformity with accounting principles generally accepted in the United States of America (GAAP) and include our accounts and the accounts of our wholly-owned subsidiaries, GeoMet Operating Company, Inc., GeoMet Gathering Company LLC, GeoMet Gathering Virginia, Inc., Hudson s Hope Gas, Ltd and Shamrock Energy LLC. All inter-company accounts and transactions have been eliminated in consolidation.

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

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 as prescribed by the United States Securities and Exchange Commission (SEC). 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 United States of America (U.S.) and Canadian cost centers.

Gas properties are depleted using the units-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. Subsequent proved reserve estimates materially different from those reported would change the depletion expense recognized during future reporting periods. No gains or losses are recognized upon the sale or disposition of gas properties unless the sale or disposition represents a significant quantity of gas reserves, which would have a significant impact on the depreciation, depletion and amortization rate.

Under full cost accounting rules, total capitalized costs are limited to a ceiling equal to the present value of estimated future net revenues, discounted at 10% per annum, plus cost of properties not being amortized 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 performed 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.

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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 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, as allowed by the guidelines of the SEC. In addition, subsequent to the adoption of Statement of Financial Accounting Standard (SFAS) No. 143, *Accounting for Asset Retirement Obligations* (SFAS 143), 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 of proved reserves together with overhead and 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 impairment to unevaluated properties is transferred to the amortization base.

Asset Retirement Liability We adopted SFAS 143*,* effective January 1, 2003. It establishes accounting and reporting standards for retirement obligations associated with tangible long-lived assets that result from the legal obligation to plug, abandon and dismantle existing wells and facilities that we have acquired, constructed or developed. It requires that the fair value of the liability for asset retirement obligations be recognized in the period in which it is incurred. Upon initial recognition of the asset retirement liability, the asset retirement cost is capitalized by increasing the carrying amount of the long-lived asset by the same amount as the liability. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset.

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

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

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

Inventory Inventory consists primarily of materials and supplies used in the development and production of coal bed methane and is recorded at the lower of cost or market value using the specific identification costing method.

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NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

Notes Receivable Included in Stockholders Equity We have loaned money to officers and employees to purchase our common stock. Such amounts, including accrued interest, are recorded as Notes Receivable, and are included as a component of Stockholders Equity. The balances at December 31, 2008 and 2007 are solely attributable to employees as all notes due from executive officers were paid in January 2006 in accordance with the rules and regulations of the SEC. See Note 12 for additional information regarding repayment.

Income Taxes We record our income taxes using an asset and liability approach in accordance with the provisions of the SFAS No. 109, *Accounting for Income Taxes* (SFAS 109) as clarified by Financial Accounting Standards Board (FASB) Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109* (FIN 48). 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 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 (NOL s).

The Company adopted the provisions of FIN 48 on January 1, 2007. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an entity s financial statements in accordance with SFAS 109, and prescribes a consistent threshold and measurement attribute for financial statement recognition and disclosure of tax positions taken, or expected to be taken, on a tax return. The adoption of this pronouncement did not have a significant impact on the Company s consolidated financial statements

Revenue Recognition and Gas Balancing We derive revenue primarily from the sale of produced natural gas. We use the sales method of accounting for the recognition of gas revenue whereby revenues, net of royalties, are recognized as the production is sold to purchaser. The amount of gas sold may differ from the amount to which the Company is entitled based on its working interest or net revenue interest in the properties. We typically do not have any significant producer gas imbalance positions because we own 100% working interest in the majority of our properties. A ready market for natural gas allows us to 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 nominations and net revenue interests. Pipeline imbalances occur when our production delivered into the pipeline varies from the gas we nominated for sale. Pipeline imbalances are settled with cash approximately thirty days from date of production and are recorded as a reduction of revenue or increase of revenue depending upon whether we are over-delivered or under-delivered.

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 during which payments are received from the purchaser.

Industry Segment and Geographic Information We operate in one industry, which is the exploration, development and production of natural gas. Our operational activities are conducted in the U.S. and Canada with only the U.S. currently having revenue generating operating results.

Concentrations of Market Risk Our future results will be affected by the market price of natural gas. The availability of a ready market for natural gas will depend on numerous factors beyond our control, including

GEOMET, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

weather, production of natural gas, imports, marketing, competitive fuels, proximity of natural gas pipelines and other transportation facilities, any oversupply or undersupply of natural gas, the regulatory environment, and other regional and political events, none of which can be predicted with certainty.

Concentration of Credit Risk Financial instruments, which subject us to concentrations of credit risk, consist primarily of cash, accounts receivable and derivative assets. We place our cash investments with highly qualified financial institutions. Risks with respect to receivables as of December 31, 2008 and 2007 arise substantially from the sales of natural gas and joint interest billings. We routinely assess the recoverability of all material trade and other receivables to determine their collectability. We accrue a reserve on a receivable when, based on management s judgment, it is probable that a receivable will not be collected and the amount of such reserve may be reasonably estimated. At December 31, 2008, we have recorded an allowance for doubtful accounts receivable of $60,848 related to other revenue and not a purchaser of our natural gas. At December 31, 2007, we did not record an allowance for doubtful accounts receivable as management had assessed accounts receivable to be recoverable. Risks with respect to derivative assets as of December 31, 2008 arise from cash settlements due to us from our derivative counterparties. We have primarily one purchaser of our natural gas production. We have not experienced any significant losses from uncollectible accounts. We do not believe the loss of our purchaser would materially affect our ability to sell the natural gas we produce as we believe other purchasers are available in our area of operations.

Fair Value of Financial Instruments The fair value of cash and cash equivalents, current receivables and payables, approximate book value because of the short maturity of these accounts. The outstanding note receivable in Other Non-Current Assets and certain Other Debt carries a fixed interest rate. See Notes 5 and 9 for the fair values of the receivable and debt.

Operating Fees and Other Operating fees and other for the years ended December 31, 2008 and 2007 include produced water disposal fees. Operating fees and other for the years ended December 31, 2006 include fees from operating coal bed methane gas fields from other owners.

Capitalized General and Administrative Expenses Under the full cost method of accounting, a portion of our general and administrative expenses that are directly attributable to our acquisition, exploration and development activities are capitalized as part of our natural gas properties. These capitalized costs include salaries, employee benefits, costs of consulting services and other costs directly associated with those activities. We capitalized general and administrative costs related to our acquisition, exploration and development activities, during the periods ended December 31, 2008, 2007 and 2006 of $2,329,748, $1,991,760, and $1,174,149, respectively.

Capitalized Interest Costs We capitalize interest based on the cost of major development projects which are excluded from current depreciation, depletion and amortization calculations. For the years ended December 31, 2008, 2007 and 2006, we capitalized $304,342, $587,884 and $1,037,576 of interest, respectively. See Unevaluated Properties above for additional information on the criteria for including costs in unevaluated properties.

Derivative Instruments and Hedging Activities. Our hedging activities consist of derivative instruments entered into to hedge against changes in natural gas prices and changes in interest rates related to outstanding debt under our credit facility primarily through the use of fixed price swap agreements, basis swap agreements, three-way collars, and traditional collars. Consistent with our hedging policy, we entered into a series of derivative instruments to hedge a significant portion of our expected natural gas production through 2009 and 2010. We also entered into an interest rate swap agreement to hedge interest rates associated with a portion of our variable rate debt through 2010. Typically, these derivative instruments require payments to (receipts from)

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counterparties based on specific indices as required by the derivative agreements. These transactions are recorded in our financial statements in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS l33). Although not risk free, we believe this policy will reduce our exposure to natural gas price fluctuations and changes in interest rates and thereby achieve a more predictable cash flow. As a result, our derivative instruments are cash flow hedge transactions in which we are hedging the variability of cash flow related to a forecasted transaction. We do not enter into derivative instruments for trading or other speculative purposes.

In accordance with SFAS 133, as amended, all our derivative instruments are recorded on the balance sheet at fair value and changes in the fair value of the derivatives are recorded each period in current earnings for the natural gas derivatives or other comprehensive income (loss) for our interest rate swaps. The natural gas derivatives have not been designated as hedge transactions while the interest rate swaps qualify and have been designated as such in accordance with SFAS 133.

At the inception of a derivative contract, we may designate the derivative as a cash flow hedge. For all derivatives designated as cash flow hedges, we document the relationship between the derivative instrument and the hedged items as well as the risk management objective for entering into the derivative instrument. To be designated as a cash flow hedge transaction, the relationship between the derivative and hedge items must be highly effective in achieving the offset of changes in cash flows attributable to the risk both at the inception of the derivative and on an ongoing basis.

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

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

Effective January 1, 2006, we adopted the fair value recognition provisions of SFAS No. 123(R), *Share-Based Payment* (SFAS 123(R)), using the prospective transition method. The application of SFAS 123(R) requires the use of an option pricing model, such as 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. For share-based awards outstanding as of January 1, 2006, we will continue using the accounting principles originally applied to those awards before adoption. Therefore, we will not recognize any equity compensation cost on these prior awards in the future unless such awards are modified, repurchased or cancelled.

Discontinued Operations We use the criteria in SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* (SFAS 144) and EITF 03-13, *Applying the Conditions in Paragraph 42 of FASB Statement No. 144 in Determining Whether to Report Discontinued Operations* (EITF 03-13), to determine whether our components that are being disposed of or are classified as held for sale are required to be reported as discontinued operations in the Consolidated Statements of Operations. To qualify as a discontinued operation under SFAS 144, the component being disposed of must have clearly distinguishable operations and cash flows.

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Additionally, pursuant to EITF 03-13, we must not have significant continuing involvement in the operations after the disposal (i.e. we must not have the ability to influence the operating or financial policies of the disposed component) and cash flows of the operations being disposed of must have been eliminated from GeoMet s ongoing operations (i.e. we do not expect to generate significant direct cash flows from activities involving the disposed component after the disposal transaction is completed). Assuming both preceding conditions are met, the related results of operations for the current and prior periods, including any related impairments, are reflected as Income From Discontinued Operations, net of income tax, in the Consolidated Statements of Operations.

Fair Value Measurement In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements (SFAS 157). SFAS 157 is effective for fiscal years beginning after November 15, 2007. Effective January 1, 2008, we adopted SFAS 157, which provides a framework for measuring fair value under GAAP. SFAS 157 defines fair value as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. SFAS 157 also establishes a fair value hierarchy that requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The standard describes three levels of inputs that may be used to measure fair value. Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 2 inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly, such as quoted prices for similar assets or liabilities; quoted prices in markets that are not active; or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities. Level 3 inputs are derived from unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities. See disclosure related to the implementation of SFAS 157 in Note 6 Derivative Instruments and Hedging Activities. The FASB has also issued Staff Position FAS 157-2 (FSP 157-2), which delays the effective date of SFAS 157 for nonfinancial assets and liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until fiscal years beginning after November 15, 2008. We have elected to defer the application of SFAS 157 thereof to nonfinancial assets and liabilities in accordance with FSP 157-2. Non-recurring nonfinancial assets and nonfinancial liabilities for which the Company has not applied the provisions of SFAS 157 include those measured at fair value in goodwill impairment testing, asset retirement obligations initially measured at fair value, and those initially measured at fair value in a business combination. On October 10, 2008, the FASB issued Staff Position No. FAS 157-3 (FSP 157-3). FSP 157-3 clarifies the application of SFAS 157 in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. On January 1, 2009, we will adopt SFAS 157 as it relates to nonfinancial assets and liabilities, including nonfinancial assets and liabilities measured at fair value in a business combination; impaired property, plant and equipment; goodwill; and initial recognition of asset retirement obligations. There has been no significant impact to our consolidated financial statements related to the implementation of SFAS 157 for our existing non-financial assets and liabilities.

Note 3 Recent Accounting Pronouncements

In December 2007, the Financial Accounting Standards Board (the FASB) issued Statement of Financial Accounting Standards No. 141R, Business Combinations (Revised 2007) (SFAS 141R), which establishes principles and requirements for how an acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest; recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase; and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS 141R is to be applied prospectively to business combinations

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for which the acquisition date is on or after the beginning of an entity s fiscal year that begins on or after Dec. 15, 2008. We will apply SFAS 141R in our consolidated financial statements for any business combinations subsequent to Jan. 1, 2009.

On February 15, 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB 115 (SFAS 159). This standard permits an entity to measure financial instruments and certain other items at estimated fair value. Most of the provisions of SFAS 159 are elective; however, the amendment to FASB 115, Accounting for Certain Investments in Debt and Equity Securities, applies to all entities that own trading and available-for-sale securities. The fair value option created by SFAS 159 permits an entity to measure eligible items at fair value as of specified election dates. The fair value option (a) may generally be applied instrument by instrument, (b) is irrevocable unless a new election date occurs, and (c) must be applied to the entire instrument and not to only a portion of the instrument. SFAS 159 is effective as of the beginning of the first fiscal year that begins after November 15, 2007. Effective January 1, 2008, we adopted SFAS 159. We did not elect the fair value option for any of our assets or liabilities that did not already require such treatment under other authoritative literature.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements (SFAS 160). SFAS 160 clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. SFAS 160 requires that changes in a parent s ownership interest in a subsidiary be reported as an equity transaction in the consolidated financial statements when it does not result in a change in control of the subsidiary. When a change in a parent s ownership interest results in deconsolidation, a gain or loss should be recognized in the consolidated financial statements. SFAS 160 must be applied prospectively as of January 1, 2009, except for the presentation and disclosure requirements, which are required to be applied retrospectively for all periods presented. The adoption of SFAS 160 did not have a material impact on our results of operations, cash flows or financial positions; however, it could impact future transactions entered into by us.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133 (SFAS 161). This standard changes the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. SFAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We are currently assessing the impact of SFAS 161 on our disclosures relating to derivative instruments and hedging activities. The statement only provides for enhanced disclosure. Therefore, adoption did not have any impact on our financial position or results of operations.

In May 2008, the FASB issued Statement No. 162, The Hierarchy of Generally Accepted Accounting Principles. The new standard is intended to improve financial reporting by identifying a consistent framework, or hierarchy, for selecting accounting principles to be used in preparing financial statements that are presented in conformity with GAAP for nongovernmental entities. Statement 162 establishes that the GAAP hierarchy should be directed to entities because it is the entity (not its auditor) that is responsible for selecting accounting principles for financial statements that are presented in conformity with GAAP. Statement 162 is effective 60 days following the SEC s approval of the Public Company Accounting Oversight Board Auditing amendments to AU Section 411, The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles. We do not expect this guidance to have a significant impact on us.

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In June 2008, the FASB issued FASB Staff Position No. EITF 03-6-1 Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities (FSP EITF 03-6-1), which addresses whether instruments granted in share-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the net income allocation in computing basic net income per share under the two class method prescribed under SFAS 128, Earnings per Share . FSP 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and, to the extent applicable, must be applied retrospectively by adjusting all prior-period net income per share data to conform to the provisions of the standard. The adoption of FSP EITF 03-6-1 is not expected to have a material effect on the Company s earnings per share calculations.

In December 2008, the SEC released Final Rule, Modernization of Oil and Gas Reporting to revise the existing Regulation S-K and Regulation S-X reporting requirements to align with current industry practices and technological advances. The new disclosure requirements include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. In addition, the new disclosure requirements require a company to (a) disclose its internal control over reserves estimation and report the independence and qualification of its reserves preparer or auditor, (b) file reports when a third party is relied upon to prepare reserves estimates or conducts a reserve audit and (c) report oil and gas reserves using an average price based upon the prior 12-month period rather than period-end prices. The provisions of this final ruling will become effective for disclosures in our Annual Report on Form 10-K for the year ended December 31, 2009.

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Note 4 Net (Loss) Income Per Share

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

	2008	2007	2006
(Loss) income from continuing operations			
Basic	$ (0.58)	$ 0.13	$ 0.49
Diluted	$ (0.58)	$ 0.13	$ 0.48
Discontinued operations			
Basic	$	$	$
Diluted	$	$	$
Net (loss) income per common share			
Basic	$ (0.58)	$ 0.13	$ 0.49
Diluted	$ (0.58)	$ 0.13	$ 0.48
Numerator			
Net (loss) income available to common stockholders	$ (22,486,591)	$ 5,169,219	$ 17,296,216
Denominator:			
Weighted average shares outstanding-basic	38,856,841	38,822,671	35,018,122
Add potentially dilutive securities:			
Stock options		877,023	946,179
Dilutive securities	38,856,841	39,699,694	35,964,301

Diluted net loss per share for the year ended December 31, 2008 excluded the effect of outstanding options to purchase 1,757,256 shares and 401,075 restricted shares because we reported a net loss which caused options to be anti-dilutive. Diluted net income per share for the year ended December 31, 2007 excluded the effect of outstanding options to purchase 640,477 shares because the average market price at December 31, 2007 was less than the exercise price. Diluted net income per share for the year ended December 31, 2006 excluded the effect of outstanding options to purchase 245,405 shares because the average market price at December 31, 2006 was less than the exercise price.

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Note 5 Note Receivable

We have an unsecured note receivable of $271,736 and $298,936 as of December 31, 2008 and 2007, respectively, from a third party included in other non-current assets. The note requires payment on a semi-monthly basis, including interest at 8.25%, of $2,168. The fair value of the receivable was $224,700 and $338,000 at December 31, 2008 and 2007, respectively. Scheduled maturities of the note receivable are detailed in the table below.

2009	$ 29,662
2010	32,346
2011	35,273
2012	38,466
2013	41,947
Thereafter	94,042
Total note receivable	271,736
Less current portion of note receivable	29,662
Non-current note receivable	$ 242,074

Note 6 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 as prescribed by the SEC. Under the full cost 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 units-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. Subsequent proved reserve estimates materially different from those reported would change the depletion expense recognized during the future reporting period. No gains or losses are recognized upon the sale or disposition of gas properties unless the sale or disposition represents a significant quantity of gas reserves, which would have a significant impact on the depreciation, depletion and amortization rate.

Under full cost accounting rules, total capitalized costs are limited to a ceiling equal to the present value of future net revenues, discounted at 10% per annum, plus the lower of cost or fair value of unevaluated properties less income tax effects (the ceiling limitation). We perform a quarterly ceiling limitation test to evaluate whether the net book value of our full cost pool exceeds the ceiling limitation. The ceiling limitation 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 ceiling limitation test is calculated using natural gas prices in effect as of the balance sheet date and adjusted for basis or location differential, held constant over the life of the reserves. In addition, subsequent to the adoption of SFAS 143, the future cash outflows associated with settling asset retirement obligations are not included in the computation of the discounted present value of future net revenues for the purposes of the ceiling limitation test calculation.

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At December 31, 2008, the carrying value of the Company s gas properties in the U.S. exceeded the full cost ceiling limitation by $19,959,547, net of income tax of $12,087,937, based upon a natural gas price of approximately $5.84 per Mcf in effect at that date. A decline in prices received for gas sales or an increase in operating costs or reductions in estimated economically recoverable quantities could result in the recognition of an impairment of gas properties in a future period. In the year ended December 31, 2008, the Company recognized an impairment of gas properties of $19,959,547, net of income tax of $12,087,937. There was no impairment of gas properties recognized in 2007 and 2006.

At December 31, 2008, the carrying value of the Company s gas properties in Canada exceeded the full cost ceiling limitation by $18,686,273 (no income tax effect as Canadian income taxes are offset by a full valuation allowance), based upon a natural gas price of approximately $5.20 per Mcf in effect at that date. A decline in prices received for gas sales or an increase in operating costs or reductions in estimated economically recoverable quantities could result in the recognition of an impairment of gas properties in a future period. In the year ended December 31, 2008, the Company recognized an impairment of gas properties of $18,686,273. There was no impairment of gas properties recognized in 2007 and 2006.

If natural gas prices at March 31, 2009 are below those prices that existed at December 31, 2008, GeoMet expects to record a non-cash impairment to the Company s natural gas properties for the quarter then ended.

Property Conveyance and Dispute

We had previously entered into an agreement to sell our interests in a property, subject to a preferential right to purchase held by another party, which the other party subsequently exercised. A dispute arose as to whether the preferential right to purchase applied to all the interests we owned in this property or just the working interests. We filed a declaratory judgment action asserting that the preferential right to purchase applied only to the working interests, and that we were entitled to retain all remaining interests we owned in the property. Following a partial agreement with the other party, we assigned all our remaining interests in the property to that party, effective July 1, 2008. On October 17, 2008, the 116th Judicial District Court of Dallas issued an order requiring us to pay $575,000 to the other party in final settlement of the issue. We have subsequently reached a settlement with the other party in the amount of $475,000, which has been accrued as a liability as of December 31, 2008. The proved reserves conveyed represented less than 1% of our total proved reserves.

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The following table provides a summary of the capitalized cost of our gas properties as of December 31, 2008 and 2007, by the year in which the costs were incurred.

	2008	2007
Subject to depletion	$ 447,968,536	$ 370,404,336
Not subject to depletion:		
Acquisition costs	5,017	6,182,214
Exploration costs		6,695,569
Total 2008	5,017	
Total 2007		12,877,783
Total 2006 and prior		12,296,981
Total not subject to depletion	5,017	25,174,764
Gross gas properties	447,973,553	395,579,100
Less impairment of gas properties	(50,733,757)	
Less accumulated depletion	(40,695,806)	(30,661,249)
Net gas properties	$ 356,543,990	$ 364,917,851

Note 7 Asset Retirement Liability

We record an asset retirement obligation (ARO) on the consolidated balance sheet and capitalize the asset retirement costs in gas properties in the period in which the retirement obligation is incurred. The amount of the ARO and the costs capitalized are equal to the estimated future costs to satisfy the obligation using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, which is then discounted back to the date the abandonment obligation was incurred using an assumed cost of funds for GeoMet. Once the ARO is recorded, it is then accreted to its estimated future value using the same assumed cost of funds.

The following table describes the changes to our asset retirement liability for the years ending December 31, 2008 and 2007.

	2008	2007
Asset retirement obligation at beginning of year	$ 2,990,242	$ 2,553,801
Liabilities incurred	237,657	247,379
Liabilities settled	(124,415)	(83,385)
Accretion expense	365,103	241,083
Revisions in estimates	1,040,014	
Currency translation adjustment	(42,240)	31,364
Asset retirement obligation at end of year	4,466,361	2,990,242
Less: current portion of obligation	117,423	74,387

Long-term asset retirement obligation	$ 4,348,938	$ 2,915,855

Revisions in estimates of our asset retirement liability totaling $1,040,014 were due primarily to specific lease agreement requirements related to plugging and abandonment of certain wells and were capitalized in the full cost pool of our gas properties.

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Note 8 Derivative Instruments and Hedging 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 using derivative instruments in the form of three-way collars, traditional collars and swaps. 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 and at times hedge forward for periods of more than two years. We generally limit the amount of these hedges during any period to no more than 50% to 60% of the then expected gas production for such future periods. 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 (a sold ceiling) and a minimum floor (a bought 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 (through a sold floor) to a predetermined amount, generally between $2.00 and $3.00 per MMBtu. We have accounted for these transactions using the mark-to-market accounting method. Generally, we incur accounting losses on derivatives during periods where prices are rising and gains during periods where prices are falling which may cause significant fluctuations in our consolidated statement of operations.

We believe that the use of derivative instruments does not expose us to material risk. However, the use of derivative instruments may materially affect our financial position and results of operations as a result of changes in the estimated market value of our natural gas derivatives. Nevertheless, we believe that use of these instruments will not have a material adverse effect on our cash flows.

The following (gains) losses on our hedging instruments included in the consolidated statements of operations are as follows:

	2008	2007	2006
Realized losses (gains) on derivative contracts	$ 500,452	$ (3,895,138)	$ (1,118,043)
Unrealized (gains) losses on derivative contracts	(4,993,238)	3,006,916	(16,877,225)
Total (gains)	$ (4,492,786)	$ (888,222)	$ (17,995,268)

Commodity Price Risk and Related Hedging Activities.

At December 31, 2008, we had the following natural gas collar positions:

Period	Volume (MMBtu)	Sold Ceiling	Bought Floor	Sold Floor	Fair Value
January through March 2009	540,000	$ 11.00	$ 8.50	$ 6.25	$ 1,138,548
January through March 2009	540,000	$ 11.00	$ 8.84	$ 6.00	$ 1,403,907
April through October 2009	1,284,000	$ 10.00	$ 7.50	$ 5.25	$ 1,615,808
April through October 2009	1,284,000	$ 10.00	$ 8.50	$ 6.50	$ 1,864,114
November 2009 through March 2010	906,000	$ 11.20	$ 9.50	$ 7.00	$ 1,297,652
Total					$ 7,320,029

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Interest Rate Risks and Related Hedging Activities

When we enter into an interest rate swap, we may designate the derivative as a cash flow hedge, at which time we prepare the documentation required under SFAS 133. Hedges of our interest rate are designated as cash flow hedges based on whether the interest on the underlying debt is converted to a fixed interest rate. Changes in derivative fair values that are designated as cash flow hedges are deferred as other comprehensive income or loss to the extent that they are effective and then recognized in earnings when the hedged transactions occur.

We use fixed rate swaps to limit our exposure to fluctuations in interest rates with the objective of realizing a fixed cash flow stream from these activities. At December 31, 2008, we had the following interest rate swaps:

Description	Effective date	Designated maturity date	Fixed rate(1)	Notional amount	Fair Value
Floating-to-fixed swap	12/14/2007	12/14/2010	3.86%	$ 15,000,000	$ (608,561)
Floating-to-fixed swap	1/3/2008	1/4/2010	3.95%	$ 10,000,000	(243,520)
Floating-to-fixed swap	3/25/2008	3/25/2010	2.38%	$ 10,000,000	(131,102)
Floating-to-fixed swap	5/13/2008	5/13/2010	3.07%	$ 5,000,000	(106,209)
Total					$ (1,089,392)

(1) The floating rate paid by the counterparty is the British Bankers Association LIBOR rate.

For the year ended December 31, 2008, there was no ineffective portion of our cash flow hedges.

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. We do not have rights to collateral from our counterparties, nor do we have rights of offset against borrowings under our credit agreement.

The application of SFAS 157 currently applies to our derivative instruments. Under the provisions of SFAS 157, we estimate the fair value of our natural gas hedges and interest rate swaps using the income approach. The income approach uses valuation techniques that convert future cash flows to a single discounted value. SFAS 157 clarifies that a fair value measurement for an asset or liability reflects its nonperformance risk, the risk that the obligation will not be fulfilled. Because nonperformance risk includes our counterparties and our credit risk, we have considered the effect of our credit risk on the fair value of the liabilities stated below. This consideration involved discounting our counterparties and our liabilities based on the difference between the S&P credit rating of a comparable company to ours and the 13-week Treasury bill rate, both at December 31, 2008. The following is a description of the valuation methodologies used for our derivative instruments measured at fair value:

Natural Gas Hedges In order to estimate the fair value of our natural gas hedge positions, a forward price curve and volatility estimates were compiled from sources that include NYMEX settlements and observed trading activity in the Over-the-Counter (OTC) markets. Pricing estimates for the theoretical market value of hedge positions were developed using analytical models accepted and employed by a broad cross-section of industry participants. To extrapolate future cash flows, discount factors incorporating our counterparties and our credit standing are used to discount future cash flows.

Interest Rate Swaps In order to estimate the fair value of our interest rate swaps, we use a yield curve based on Money Market rates and Interest Rate swaps, extrapolate a forecast of future interest rates, estimate each future cash flow, derive discount factors to value the fixed and floating rate cash flows of each swap, and then discount to present value all known (fixed) and forecasted (floating) swap cash flows. Curve building and discounting techniques used to establish the theoretical market value of

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interest bearing securities are based on readily available Money Market rates and Interest Rate swap market data. To extrapolate future cash flows, discount factors incorporating our counterparties and our credit standing are used to discount future cash flows. Based on the use of observable market inputs, we have designated these types of instruments as Level 2 for SFAS 157 reporting purposes. The fair value of our derivative instruments at December 31, 2008 and 2007 were as follows:

	2008	2007
Interest rate swap asset	$	$ 10,884
Natural gas hedge asset	7,320,029	2,326,791
Total derivative assets	$ 7,320,029	$ 2,337,675
Interest rate swap liability	$ 1,089,392	$
Natural gas hedge liability		
Total derivative liabilities	$ 1,089,392	$

Note 9 Long-Term Debt

At December 31, 2008, we had a borrowing base of $180 million, maturing January 6, 2011. On March 12, 2009, the Company s bank syndicate approved a borrowing base of $140 million after completing its year-end borrowing base determination. The next regular borrowing base determination, which will be based on a June 30, 2009 reserve report prepared by the Company, is scheduled to be complete on or before December 16, 2009. Under the terms of the determination, our borrowing cost was increased by approximately 100 basis points and the fee on the undrawn portion of the borrowing base was increased by 12.5 basis points. Our revolving credit facility permits us to borrow and repay amounts as needed based on the available borrowing base as determined in the credit agreement. The revolving credit facility is secured by substantially all of our gas properties and the capital stock of our subsidiaries. The borrowing base under the revolving credit facility is based upon the reserve valuation of our gas properties as of June 30 and December 31 of each year and other factors deemed relevant by the lenders, including Bank of America as agent. The lenders may also request one additional borrowing base re-determination in any fiscal year.

As of December 31, 2008, we had $116.5 million of borrowings outstanding under our revolving credit facility, resulting in a borrowing availability of $63.5 million under our $180 million borrowing base. For the years ended December 31, 2008 and 2007 we borrowed $115 million and $83 million, respectively, and made payments of $94.5 million and $47 million, respectively, under the revolving credit facility. The outstanding balances on the revolving credit facility bear interest at the bank s adjusted base rate, which is the bank s base rate of at least the Federal Funds Rate plus 0.5%, or the adjusted LIBOR rate, plus a margin of 1.00% to 2.00%, based on borrowing base usage. The rates at December 31, 2008 and 2007, excluding the effect of our interest rate swaps, were 2.49% and 6.29%, respectively.

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The following is a summary of our long-term debt at December 31, 2008 and 2007:

	December 31, 2008	December 31, 2007
Borrowings under revolving credit facility	$ 116,500,000	$ 96,000,000
Note payable to a third party, annual installments of $53,000 through January 2011, interest-bearing at 8.25% annually, unsecured	135,972	174,570
Note payable to an individual, semi-monthly installments of $644, through September 2015, interest-bearing at 12.6% annually, unsecured	118,735	129,240
Salary continuation payable to an individual, semi-monthly installments of $3,958, through December 2015, non-interest-bearing (less amortization discount of $572,074, with an effective rate of 8.25%), unsecured	475,015	528,498
Total debt	117,229,722	96,832,308
Less current maturities included in current liabilities	(111,767)	(102,586)
Total long-term debt	$ 117,117,955	$ 96,729,722

We are subject to certain restrictive financial and non-financial covenants under the credit agreement, including a minimum current ratio, adjusted for unrealized (gains) losses on derivative contracts and borrowing availability, of 1.0 to 1.0, and a rate of consolidated EBITDA to interest expense of up to 2.75 to 1.0, both as defined in the credit agreement. As of December 31, 2008, we were in compliance with all of the financial covenants in the credit agreement.

The following were maturities of long-term debt for each of the next five years at December 31, 2008:

Year	Amount
2009	$ 111,767
2010	121,792
2011	116,632,744
2012	91,757
2013	100,467
Thereafter	171,195
Total Debt	$ 117,229,722

The fair value of long-term debt at December 31, 2008 and 2007 is approximately $92,485,449 and $83,384,209, respectively. SFAS 157 clarifies that a fair value measurement for an asset or liability reflects its nonperformance risk, the risk that the obligation will not be fulfilled. Because nonperformance risk includes our credit risk, we have considered the effect of our credit risk on the fair value of the long-term debt. This consideration involved discounting our long-term debt based on the difference between the S&P credit rating of a comparable company to ours and the stated interest rates of the debt instruments included our long-term debt, both at December 31, 2008.

Note 10 Discontinued Operations

As of September 30, 2007, we discontinued the third-party marketing business and second reportable segment which had been created in connection with the consolidation of Shamrock Energy LLC, a variable interest entity under FIN 46(R) on August 1, 2006. The consolidation of the variable interest entity had no impact

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on our net income (loss) due to the 100% minority interest to Shamrock Energy LLC. On January 1, 2007, we exercised our purchase option and acquired 100% of Shamrock Energy LLC, our discontinued gas marketing subsidiary. Over 99% of the net assets acquired were current, approximated their fair value and were equal to zero. Shamrock Energy LLC was a low margin business and as a result it did not have a significant impact on our results of operations. The acquisition was accounted for as a purchase in accordance with SFAS 141, whereby the purchase price of the net assets acquired was allocated to those net assets based on their fair value. Goodwill was not recorded because the purchase price approximated the fair value of the net assets acquired.

As a result of exiting the third-party marketing business, we are treating these activities as a discontinued operation for all the periods presented. Results for activities reported as discontinued operations were as follows:

Statement of Operations Data (for the year ended December 31):

	2008	2007	2006
Gas marketing revenues	$	$ 21,873,248	$ 13,043,598
Purchased gas expense		(21,595,540)	(12,898,973)
General and administrative expense			(254,086)
Elimination of intercompany profit			146,151
Income from discontinued operations before tax		277,708	36,690
Income tax expense		(103,926)	(14,155)
Minority interest			(22,535)
Income from discontinued operations	$	$ 173,782	$

Balance Sheet Data:

	December 31, 2008	December 31, 2007
Assets:		
Cash and cash equivalents	$	$ 175,398
Accounts receivable		15,530
Other		14,945
Total assets	$	$ 205,873
Liabilities:		
Accounts payable	$	$ 86,510
Stockholder s equity		119,363
Total liabilities and stockholder s equity	$	$ 205,873

Note 11 Income Taxes

We record our income taxes using an asset and liability approach in accordance with the provisions of the FASB Statement No. 109, *Accounting for Income Taxes,* as clarified by FIN 48. This results in the recognition of deferred tax assets and liabilities using estimated effective tax rates for the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities using enacted tax rates at the end of the period. Under FASB 109, the effect of a change in tax rates of deferred tax assets and liabilities is recognized in the year of the enacted change.

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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 Section 382 of the Internal Revenue Code. We have a significant deferred tax asset associated with net operating loss carryforwards (NOL s). It is more likely than not that we will use the NOL s in the U.S. to offset current tax liabilities in future years.

Our effective tax rate differs from the federal statutory rate primarily due to losses in Canada that we are unable to benefit from and state income taxes. The Canadian losses, as well as certain state losses, are fully reserved because it is more likely than not that we will not use those NOL s to offset current tax liabilities in future years.

Uncertain Tax Positions

We adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, we identified $269,900 of unrecognized tax benefits, largely related to depletion methods used in years prior to 2006 from net deferred tax assets. There was no cumulative effect adjustment to retained earnings, our financial condition or results of operations as a result of implementing FIN 48 principally due to the size of our NOL s. The amount of unrecognized tax benefits has not materially changed and as of December 31, 2008 and 2007 was $272,600.

It is expected that the amount of unrecognized tax benefits may change in the next twelve months; however we do not expect the change to have a significant impact on our results of operations or the financial position.

We file a consolidated federal income tax return in the U.S. and various combined and separate filings in Canada and several state and local jurisdictions. With limited exceptions, we are no longer subject to U.S. federal, state and local, or non-U.S. income tax examinations by tax authorities for years before 2002.

Our continuing practice is to recognize estimated interest related to potential underpayment on any unrecognized tax benefits as a component of interest expense in the consolidated statement of operations. Penalties, if incurred, would be recognized as a component of penalty expense. As of the date of adoption of FIN 48, we did not have any accrued interest or penalties associated with any unrecognized tax benefits, nor was any interest expense recognized during the years ended December 31, 2008 and 2007.

We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits and the expiration of statute of limitations prior to December 31, 2009.

For tax reporting purposes, we have federal and state NOL s of approximately $78,075,499 and $5,890,879, respectively, at December 31, 2008 that are available to reduce future taxable income. If not utilized, the federal carryforwards would begin to expire in 2022. Certain immaterial portions of the state NOL s will expire prior to 2022. Our long-term deferred tax asset does not include $7.2 million in deferred tax asset related to our Canadian operations and gas properties as it has been fully valued in accordance with SFAS 109.

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An analysis of our deferred taxes follows:

	2008	2007
Current deferred tax asset:		
Compensation expense and other	$ 93,012	$ 83,616
Total current deferred tax asset	93,012	83,616
Current deferred tax liability:		
Book basis in excess of tax basis of derivative contracts	(2,519,810)	(854,291)
Net current deferred tax liability	$ (2,426,798)	$ (770,675)
Long-term deferred tax asset:		
Net operating loss carryforward	$ 30,937,418	$ 28,972,421
Compensation expense and other	240,993	240,158
Accrued asset retirement obligations	1,051,917	966,442
Alternative minimum tax credit carryforward	115,907	115,907
Total long-term deferred tax assets	32,346,235	30,294,928
Long-term deferred tax liabilities:		
Book basis in excess of tax basis of derivative contracts	(276,442)	(34,543)
Book basis of gas properties in excess of tax basis	(75,911,743)	(76,906,264)
Total long-term deferred tax liabilities	(76,188,185)	(76,940,807)
Net long-term deferred tax liability	$ (43,841,950)	$ (46,645,879)

Federal income tax expense from continuing operations for each of the years ended December 31, 2008, 2007, and 2006 was different than the amount computed using the Federal statutory rate for the following reasons:

	2008	%	2007	%	2006	%
Amount computed using statutory rates	$ (7,887,487)	34.00%	$ 2,714,167	34.00%	$ 9,575,022	34.00%
State income taxes net of federal benefit	(147,556)	0.64%	(84,618)	-1.06%	980,032	3.48%
Valuation Allowance	7,071,215	-30.48%	296,722	3.72%	204,550	0.73%
Nondeductible items and other	251,928	-1.09%	61,136	0.77%	106,010	0.38%
Income tax (benefit) provision	$ (711,900)	3.07%	$ 2,987,407	37.42%	$ 10,865,614	38.58%

The effective tax rate in 2008 of 3.07% was due to the full valuation of the deferred income tax benefit of $6,565,447 related to our Canadian impairment of gas properties recorded in 2008.

The following components of the federal income tax expense for the years ended December 31, 2008, 2007 and 2006 are as follows:

	Years Ended December 31, 2008	2007	2006
Current:			
State	$ 25,000	$ 25,000	$ 142,238
Federal			
Deferred:			
State	(106,231)	(109,618)	837,794
Federal	(630,669)	3,072,025	9,885,582
Income tax provision	$ (711,900)	$ 2,987,407	$ 10,865,614

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Note 12 Common Stock

At December 31, 2008 and 2007, there were 39,049,684 shares and 38,962,359 shares, respectively, of common stock outstanding, including 10,432 shares and 7,828 shares, respectively, of treasury stock held by the Company. For the years ended December 31, 2008 and 2007, a total of 68,605 and 105,565 shares, respectively, of common stock were issued upon the exercise of stock options granted under our 2005 Stock Option Plan. In March 2008, we issued 253,806 shares of restricted stock to key employees, as well as 5 executive officers and two other officers, of the Company and 18,720 shares of common stock to our independent directors, representing 50% of their annual retainer. In September 2008, we issued 46,694 shares of restricted stock to key employees of the Company. The shares of common stock for our independent directors and the restricted stock were issued pursuant to our 2006 Long-Term Incentive Plan. Additionally, for the years ended December 31, 2008 and 2007, 45,032 shares and 31,500 shares of restricted stock, respectively, were forfeited. No shares of restricted stock were forfeited for the year ended December 31, 2006. For the year ended December 31, 2006, a total of 637,026 shares of common stock were issued upon the exercise of stock options.

Effective January 24, 2006, our board of directors approved a four-for-one common stock split and increased our authorized capital stock from 40,000,000 shares of common stock at January 1, 2006 to 135,000,000 shares of capital stock, consisting of 125,000,000 shares of common stock and 10,000,000 shares of preferred stock. Prior periods have been adjusted for the stock split.

On January 30, 2006 and February 7, 2006, we completed private equity offerings of an aggregate 10,250,000 shares of our common stock, consisting of 2,317,023 shares issued by us and 7,932,977 shares sold by certain of our existing stockholders, to qualified institutional buyers exempt from registration under the Securities Act. We received aggregate consideration of approximately $28.0 million, or $12.09 per share. We did not receive any proceeds from the shares sold by certain of our existing stockholders. In addition, we received approximately $17.5 million from certain of the selling stockholders for repayment of loans from us, including accrued and unpaid interest thereon. We used the net proceeds from this private equity offering, together with the proceeds from the repayment of certain of the selling stockholders loans, to repay a portion of the borrowings under our revolving credit facility and for general corporate purposes.

On July 27, 2006, we registered for re-sale with the SEC the 10,250,000 shares of common stock issued in the private equity offering discussed above. Also on July 27, 2006, we sold 5,750,000 shares of our common stock under an underwritten initial public offering. Our initial public offering closed on August 2, 2006, and the price per share was $10.00. We received net proceeds of approximately $52.6 million from our initial public offering after deducting estimated offering expenses and underwriting discounts and commissions. We used the net proceeds from the initial public offering to reduce outstanding borrowings under our revolving credit facility.

Note 13 Share-Based Awards

Effective January 1, 2006, we adopted the fair value recognition provisions of Statement of Financial Accounting Standards No. 123(R), Share-Based Payment , using the prospective transition method. For share-based awards outstanding as of January 1, 2006, we will continue using the accounting principles originally applied to those awards before adoption. Therefore, we will not recognize any equity compensation cost on these prior awards in the future unless such awards are modified, repurchased or cancelled.

As of December 31, 2008, we have two stock-based award plans authorized, our 2005 Stock Option Plan and our 2006 Long-Term Incentive Plan. However, we will not grant any additional awards under our 2005 Stock Option Plan now that we have adopted our 2006 Long-Term Incentive Plan, although we will continue to issue shares of our common stock upon exercise of awards previously granted under the 2005 Stock Option Plan.

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Our 2006 Long-Term Incentive Plan authorized the granting of incentive stock options, non-qualified stock options, stock appreciation rights, stock awards, restricted stock, restricted stock units and performance awards. A maximum of 2,000,000 shares is available for grant under this plan. The 2006 Long-Term Incentive Plan is available to our employees and independent directors and is designed to attract and retain employees and independent directors, to further align the interests of our employees and independent directors with the interests of our stockholders, and to closely link compensation with our performance. The exercise price of stock options granted under this plan may not be less than the fair market value of the common stock on the date of grant. The options generally have a term of seven years and vest evenly over three years, except performance based awards and options issued to directors. Performance based awards granted under the 2006 Long-Term Incentive Plan vest once the performance criteria have been met. Options issued to our directors vest immediately.

In March 2007, we granted 168,975 share-based stock option awards and in June 2007 we granted 138,000 restricted stock awards to certain of our non-executive employees with time vesting criteria. In September 2007 we granted 219,279 share-based stock option awards and we also granted 30,145 restricted stock awards, including 20,145 with performance-based vesting to our named executive officers and two other officers. In November 2007 we granted 19,841 incentive stock options, 20,000 restricted stock awards and 40,159 non-qualified stock options to an officer that vest on March 15, 2010. In March 2008, we granted 164,604 restricted stock awards with time vesting criteria to certain key employees, including our four executive officers. Additionally, we granted 89,202 restricted stock awards with performance vesting criteria to our four executive officers and two other officers. We also granted 18,720 shares of common stock to our independent directors, representing 50% of their annual retainer. In September 2008, we granted 46,694 restricted stock awards with time vesting criteria to certain key employees.

During 2007, we recorded a compensation expense accrual of $526,576 which was allocated among lease operating expenses ($118,830), general and administrative expenses ($118,830), and capitalized to unevaluated gas properties ($215,093). During 2008, we recorded a compensation expense accrual of $941,697 which was allocated among lease operating expenses ($53,737), general and administrative expenses ($512,680), and capitalized to unevaluated gas properties ($375,280). The future compensation cost of all the outstanding awards is $ 1,714,327 which will be amortized over the vesting period of such stock options and restricted stock. The weighted average remaining useful life of the future compensation cost is 1.41 years.

For the year ended December 31, 2008, no stock options were granted. For the year ended December 31, 2007, the significant assumptions used in determining the compensation costs included a dividend yield of 0%, expected volatility of 40.20%, risk-free interest rate of 4.02%, an expected term of 4.5 years, forfeiture rates from 5% to 15%, and no expected dividends. For the year ended December 31, 2006, the significant assumptions used in determining the compensation costs included a dividend yield of 0%, expected volatility of 36.95%, risk-free interest rate of 4.87%, an expected term of 4.5 years, forfeiture rates from 5% to 15%, and no expected dividends.

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GEOMET, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

Incentive Stock Options

The table below summarizes incentive stock option activity for the year ended December 31, 2008:

	Number of Options	Weighted Average Exercise Price	Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at December 31, 2007	682,277	$ 6.96		
Forfeited	(136,503)	$ 5.63		
Exercised	(68,605)	$ 1.72		
Outstanding at December 31, 2008	477,169	$ 8.09	4.43	$ 4,008
Options exercisable at December 31, 2008	279,126	$ 7.84	3.83	$ 4,008

During the year ended December 31, 2008, no incentive stock options were granted. The weighted average grant-date fair value of incentive stock options granted during the years 2007 and 2006 was $2.32 and $4.85, respectively. The total intrinsic value of incentive stock options exercised during the years ended December 31, 2008, 2007, and 2006 was $0.6 million, $0.5 million and $5.2 million, respectively.

Non-Qualified Stock Options

The table below summarizes non-qualified stock option activity for the year ended December 31, 2008:

	Number of Options	Weighted Average Exercise Price	Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at December 31, 2007	1,311,055	$ 4.02		
Forfeited	(30,968)	$ 10.22		
Outstanding at December 31, 2008	1,280,087	$ 3.87	4.32	$
Options exercisable at December 31, 2008	1,156,313	$ 3.33	4.20	$

During the years ended December 31, 2008 and 2007, no non-qualified stock options were granted or exercised. The total intrinsic value of non-qualified stock options exercised during the year ended December 31, 2006 was $1.7 million. During the year ended December 31, 2008, no non-qualified stock options were granted. The weighted average grant-date fair value of non-qualified stock options granted during the years 2007 and 2006 was $1.18 and $4.96, respectively.

Restricted Stock Awards

The table below summarizes non-vested restricted stock awards activity for the year ended December 31, 2008:

	Number of Options	Weighted Average Value at Grant Date
Non-vested restricted stock at December 31, 2007	173,998	$ 7.21
Granted	300,500	$ 6.34
Forfeited	(45,032)	$ 6.84
Vested	(28,391)	$ 7.23
Non-vested restricted stock at December 31, 2008	401,075	$ 6.60

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GEOMET, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

On April 18, 2007, 4,083 shares of restricted stock vested. The fair value of the shares that vested on that date was $35,604. On June 15, 2008, 20,800 shares of restricted stock vested. The fair value of the shares that vested on that date was $186,576. On September 20, 2008, 5,591 shares of restricted stock vested. The fair value of the shares that vested on that date was $33,266. On September 24, 2008, 2,000 shares of restricted stock vested. The fair value of the shares that vested on that date was $11,760. There has been no vesting of restricted stock other than described above.

Note 14 Profit Sharing Plan

Substantially all of the employees are covered by our profit sharing plan under Section 401(k) of the Internal Revenue Code. Eligible employees may make contributions to the plan by electing to defer some of their compensation. We are required to match 100 percent of total contributions up to a total of five percent of their annual compensation. Our matching contribution vests evenly over three years. Our contributions to the Plan for the years ended December 31, 2008, 2007 and 2006 were $264,305, $170,062 and $137,357, respectively.

Note 15 Commitments and Contingencies

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

CNX Surface Use Disputes

Buchanan County Dispute. On September 12, 2008, the Virginia Supreme Court issued its decision in this matter in favor of us and PMC, reversing and remanding the matter to the Buchanan Circuit Court for further action consistent with the decision. The Court held that CNX Gas Company LLC (CNX) does not have the exclusive right to transport gas across the Pocahontas Mining Limited Liability Company (PMC) property and may not prevent uses of the PMC property that do not conflict with the exercise of CNX s rights under its CBM lease with PMC. The effect of this ruling is that our pipeline right of way with PMC is valid.

Tazewell County Dispute. 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 tract 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 Pond Creek gathering line across the property. We and CNX have since reached a resolution of this dispute. The settlement had no material impact on our financial position, results of operations, or cash flows presented herein.

CNX Antitrust Action

We filed a complaint against CNX and Island Creek Coal Company (Island Creek), an affiliate of CNX, in the Circuit Court of Tazewell County, Virginia on February 14, 2007, in which we sought 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 sought compensatory and consequential damages for alleged violations of the Virginia Antitrust Act, including alleged anticompetitive efforts of CNX to dominate

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GEOMET, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

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 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 alleged CNX s intentional interference with our existing and prospective third-party business relationships in an attempt to harm us and improve CNX s position and corporate and financial interests. In accordance with an opinion issued by the Tazewell Circuit Court in December 2007, we have filed an amended petition that restates with specificity our claims against CNX and Island Creek, names Cardinal States Gathering Company and CONSOL Energy Inc., the ultimate parent of the other defendants, as additional defendants, and seeks actual damages of $385.6 million. We are seeking treble damages for the alleged violations of the Virginia Antitrust Act, as well as injunctive relief to prevent CNX and other parties from continuing these alleged anticompetitive activities.

Environmental and Regulatory

As of December 31, 2008, there were no known environmental or other regulatory matters related to our operations that are reasonably expected to result in a material liability to us.

Operating Lease Commitments We have operating leases for office space, office equipment and field compressors expiring in various years through 2014. Future minimum lease commitments as of December 31, 2008 under non-cancelable operating leases having remaining terms in excess of one year are as follows:

Year Ended December 31,	**Amount**
2009	$ 1,454,665
2010	1,393,872
2011	1,353,290
2012	551,458
2013	311,334
Thereafter	322,380
Total future minimum lease commitments	$ 5,386,999

Total rental expenses under operating leases were approximately $2,005,994, $1,542,660 and $1,591,027 for the years ended December 31, 2008, 2007 and 2006, respectively.

Transportation Contracts As of December 31, 2008, under the following firm transportation contracts, we can transport maximum daily volumes of (1) 7,000 MMBtu s continuing until October 31, 2010, (2) 10,000 MMBtu s continuing until October 31, 2011, (3) 15,000 MMBtu s continuing until April 1, 2022, and (4) 10,000 MMBtu s continuing until April 1, 2017. We have a right to extend each of these contracts, in five-year increments, at the maximum tariff rate. As of December 31, 2008, the maximum commitment remaining under the transportation contracts is approximately $17.7 million.

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SUPPLEMENTARY FINANCIAL AND OPERATING INFORMATION ON GAS

EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES (UNAUDITED)

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

Capitalized Costs Capitalized costs and accumulated depreciation, depletion, amortization and impairment of gas properties relating to our gas producing activities, all of which are conducted within the continental U.S. and Canada, at December 31, 2008, 2007 and 2006 are summarized below.

We capitalize certain payroll and other internal costs directly attributable to acquisition, exploration and development activities as part of our investment in natural gas properties over the periods benefited by these activities. During the years ended December 31, 2008, 2007 and 2006, these capitalized costs amounted to $2,329,748, $1,991,760 and $1,174,148, respectively. Capitalized costs do not include any costs related to production, general corporate overhead or similar activities. Capitalized costs in 2007 include a $3.0 million purchase price adjustment for a 2004 acquisition. For the years ended December 31, 2008, 2007 and 2006, interest costs of $304,342, $587,884 and $1,037,576, respectively, were capitalized.

	For the Years Ended December 31,		
	2008	2007	2006
Unevaluated properties U.S.	$ 5,017	$ 6,651,594	$ 13,680,374
Unevaluated properties Canada		18,523,170	12,717,608
Properties subject to amortization U.S.	447,968,536	370,404,336	310,011,154
Capitalized costs consolidated	447,973,553	395,579,100	336,409,136
Accumulated depreciation, depletion, amortization and impairment of gas properties U.S.	(91,429,563)	(30,661,248)	(21,836,904)
Net capitalized costs consolidated	356,543,990	364,917,852	314,572,232
Net capitalized costs Canada	3,844,991	18,523,170	12,717,608
Net capitalized costs U.S.	352,698,999	343,394,682	301,854,624
Net capitalized costs consolidated	$ 356,543,990	$ 364,917,852	$ 314,572,232

Capitalized Costs Incurred

The following table discloses costs incurred in gas property acquisition, exploration and development activities for the years ended December 31, 2008, 2007 and 2006.

	For the Years Ended December 31,		
	2008	2007	2006
Acquisition costs:			
Proved U.S.	$ 3,153,568	$ 3,827,641	$ 428,729
Unproved U.S.	2,779,865	4,883,982	9,113,502
Exploration costs U.S.	6,055,041	1,937,858	2,559,745
Development costs U.S.	34,670,459	42,561,606	62,654,438
Total costs incurred U.S.	46,658,933	53,211,087	74,756,414

Acquisition costs-proved Canada	65,251		
Acquisition costs-unproved Canada		435,133	1,717,097
Exploration costs incurred Canada	51,542	5,523,744	5,119,289
Development costs incurred Canada	5,618,726		
Total costs incurred Canada	5,735,519	5,958,877	6,836,386
Total costs incurred consolidated	$ 52,394,452	$ 59,169,964	$ 81,592,800

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

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

	2008	2007	2006
Natural Gas Reserves (Mcf) U.S.			
Proved reserves at beginning of year	350,176,000	325,663,000	262,512,000
Revisions of previous estimates	(42,708,000)	(15,343,000)	28,417,000
Extensions and discoveries	17,613,000	46,982,000	39,138,000
Acquisition			1,824,000
Disposition	(1,917,000)		
Production	(7,453,000)	(7,126,000)	(6,228,000)
Proved reserves at end of year	315,711,000	350,176,000	325,663,000
Proved developed reserves at beginning of year	266,943,000	242,918,000	195,139,000
Proved developed reserves at end of year	242,518,000	266,943,000	242,918,000

	2008	2007	2006
Natural Gas Reserves (Mcf) Canada			
Proved reserves at beginning of year			
Revisions of previous estimates			
Extensions and discoveries	3,818,000		
Acquisition			
Disposition			
Production			
Proved reserves at end of year	3,818,000		
Proved developed reserves at beginning of year			
Proved developed reserves at end of year	3,818,000		

The following table presents the standardized measure of future net cash flows related to proved gas reserves in accordance with SFAS 69. All components of the standardized measure are from proved reserves, all of which are located entirely within the continental U.S. and Canada. As prescribed by this statement, the amounts shown are based on prices and costs at December 31, 2008, 2007 and 2006, and assume continuation of existing economic conditions. Future income taxes are based on year-end statutory rates, adjusted for tax credits. A discount factor of 10 percent was used to reflect the timing of future net cash flows. Extensive judgments are involved in estimating the timing of future production and the costs that will be incurred throughout the remaining lives of the fields. Accordingly, the estimates of future net revenues from proved reserves and the present value thereof may not be materially correct when judged against actual subsequent results. Further, since prices and costs do

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not remain static, and no price or cost changes have been considered, and future production and development costs are estimated to be incurred in developing and producing the estimated proved gas reserves, the results are not necessarily indicative of the fair market value of estimated proved reserves, and the results may not be comparable to estimates disclosed by other gas producers.

Standardized Measure U.S.	**2008**	**2007**	**2006**
Future cash inflows	$ 1,844,199,000	$ 2,654,214,000	$ 1,858,104,000
Future production costs	(727,785,000)	(725,272,000)	(501,955,000)
Future development costs	(105,707,000)	(106,356,000)	(101,777,000)
Future income taxes	(290,341,000)	(602,319,000)	(410,391,000)
Future net cash flows	720,366,000	1,220,267,000	843,981,000
10% annual discount to reflect timing of cash flows	(413,859,000)	(724,399,000)	(484,494,000)
Standardized measure of discounted future net cash flows	$ 306,507,000	$ 495,868,000	$ 359,487,000

Standardized Measure Canada	**2008**	**2007**	**2006**
Future cash inflows	$ 20,932,000		
Future production costs	(7,126,000)		
Future development costs	(30,000)		
Future income taxes			
Future net cash flows	13,776,000		
10% annual discount to reflect timing of cash flows	(9,936,000)		
Standardized measure of discounted future net cash flows	$ 3,840,000		

Changes in standardized measure relating to proved gas reserves for the years ended December 31, 2008, 2007 and 2006 are summarized below:

Changes in Standardized Measure	**2008**	**2007**	**2006**
Standardized measure at beginning of year	$ 495,868,000	$ 359,487,000	$ 632,665,000
Sales and transfers of oil and gas produced net of production cost	(46,908,000)	(29,340,000)	(27,705,000)
Net changes in prices and production cost	(238,413,000)	248,627,000	(412,865,000)
Extensions and discoveries	17,666,000	58,936,000	63,721,000
Acquisition/disposition (net)	(9,708,000)		1,278,000
Net change in development cost	19,685,000	(43,181,000)	(4,187,000)
Revision of previous quantity estimates	(55,087,000)	(35,222,000)	49,362,000
Accretion of discount before income taxes	66,281,000	52,563,000	88,015,000
Net change in income taxes	125,336,000	(8,678,000)	81,343,000
Changes in production rates (timing) and other	(64,373,000)	(107,324,000)	(112,140,000)
Subtotal net change	(185,521,000)	136,381,000	(273,178,000)
Standardized measure at end of year	$ 310,347,000	$ 495,868,000	$ 359,487,000

The weighted average prices of gas used with the above tables at December 31, 2008, 2007 and 2006 were $5.84, $7.58 and $5.63 per Mcf, respectively.

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GEOMET, INC.

QUARTERLY RESULTS OF OPERATIONS (Unaudited)

Quarterly Results of Operations. The following table sets forth the results of operations by quarter for the years ended December 31, 2008 and 2007 (in thousands):

	Quarter Ended			
	Mar. 31	**Jun. 30**	**Sept. 30**	**Dec. 31**
Fiscal Year 2008:				
Total revenues	$ 15,879	$ 20,904	$ 18,820	$ 13,491
Impairment of gas properties	$	$	$	$ (50,734)
Operating (loss) income from continuing operations	$ (2,074)	$ (3,343)	$ 29,169	$ (42,248)
Net (loss) income	$ (2,142)	$ (3,177)	$ 17,482	$ (34,650)
Net (loss) income per share:				
Basic	$ (0.05)	$ (0.08)	$ 0.44	$ (0.89)
Diluted	$ (0.05)	$ (0.08)	$ 0.44	$ (0.89)
Fiscal Year 2007:				
Total revenues	$ 12,140	$ 13,763	$ 11,644	$ 13,437
Operating (loss) income from continuing operations	$ (702)	$ 6,085	$ 3,465	$ 4,284
Net (loss) income	$ (1,025)	$ 2,998	$ 1,588	$ 1,608
Net (loss) income per share:				
Basic	$ (0.03)	$ 0.08	$ 0.04	$ 0.04
Diluted	$ (0.03)	$ 0.08	$ 0.04	$ 0.04

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Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

None.

Item 9A. ***Controls and Procedures***

Disclosure controls and procedures are controls and other procedures that are designed to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act is recorded, processed, summarized, and reported, within the time periods specified by the SEC s rules and forms and include, without limitation, controls and procedures designed to provide reasonable assurance that information required to be disclosed by us is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Under the supervision and with the participation of management, our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rule 13a-15(e) and 15d-15(e) of the Exchange Act) as of December 31, 2008, and, based upon this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that these controls and procedures are effective in providing reasonable assurance that information requiring disclosure is recorded, processed, summarized, and reported within the timeframe specified by the SEC s rules and forms.

Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, we have evaluated our internal controls over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the year ended December 31, 2008 and found no change that has materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

Management s Annual Report On Internal Control Over Financial Reporting

Management of GeoMet, Inc. (the Company), including the Company s Chief Executive Officer and Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. The Company s internal control system was designed to provide reasonable assurance to the Company s Management and Directors regarding the preparation and fair presentation of published financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management conducted an evaluation of the effectiveness of internal control over financial reporting based on the *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company s internal control over financial reporting was effective as of December 31, 2008.

/s/ J. Darby Seré	/s/ William C. Rankin
J. Darby Seré,	**William C. Rankin**
Chief Executive Officer	**Chief Financial Officer**

Houston, Texas

March 12, 2009

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Item 9B. ***Other Information***

Certain of our non-employee directors and our largest stockholder may from time to time have investments in other exploration and production companies that may compete with us. Section 122(17) of the Delaware General Corporation Law permits a Delaware corporation, such as GeoMet, to renounce by action of its board of directors any interest or expectancy of the corporation in certain opportunities, effectively eliminating the ambiguity in a Delaware corporation s ability to do so in advance arising out of prior Delaware case law. Under corporate law concepts of fiduciary duty, our officers and directors generally have a duty to disclose to us opportunities that are related to our business and are generally prohibited from pursuing those opportunities unless we determine that we are not going to pursue them.

On March 12, 2009, we entered into a Business Opportunities Agreement with two of our non-employee directors and our largest shareholder. This agreement provides that so long as any of these persons, which we refer to as Designated Parties, is serving as a member of our board of directors, we renounce in advance any interest or expectancy in any business opportunity, transaction or other matter in and that involves any aspect of the oil and gas exploration, exploitation, development and production other than:

any business opportunity that is brought to the attention of a Designated Party solely in such person s capacity as a director of our company and with respect to which, at the time of such presentment, no other Designated Party has independently received notice or otherwise identified such opportunity; or

any business opportunity that is identified by a Designated Party solely through the disclosure of information by or on behalf of us.

Under the terms of this Business Opportunities Agreement as approved by our board of directors, a Designated Party will not be required to inform us of a business opportunity that he becomes aware of so long as he did not become aware of the opportunity as a consequence of serving as a member of our board of directors. Furthermore, the Designated Party will be permitted to pursue that opportunity even if it is competitive with our business. This Business Opportunities Agreement does not prohibit us from pursuing any business opportunity to which we have renounced any interest or expectancy. It will provide the Designated Parties and their respective affiliates with some certainty that opportunities that they independently pursue will not be required to be first offered to us.

The form of Business Opportunities Agreement is attached to this Form 10-K as exhibit 10.20.

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PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

The information required by this item is incorporated herein by reference to the 2009 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2008. Pursuant to Item 401(b) of Regulation S-K, the information required by this item with respect to our executive officers is set forth in Part I of this report.

Item 11. ***Executive Compensation***

The information required by this item is incorporated herein by reference to the 2009 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2008.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

The information required by this item is incorporated herein by reference to the 2009 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2008.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence***

The information required by this item is incorporated herein by reference to the 2009 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2008.

Item 14. ***Principal Accountant Fees and Services***

The information required by this item is incorporated herein by reference to the 2009 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2008.

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PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

List of Documents Filed as Part of this Report

(1) Financial Statements

(2) Financial Statement Schedules

None.

(3) Exhibits:

The following is a list of exhibits filed as part of this Form 10-K. Where so indicated, previously filed exhibits are incorporated herein by reference.

[to add Business Opportunities Agreement]

Exhibit No.	Description
3.1	Form of Amended and Restated Certificate of Incorporation of GeoMet, Inc. (incorporated herein by reference to Exhibit 3.1 to the Company s Registration Statement on Form S-1 filed on July 25, 2006 (Registration No. 333-131716)).
3.2	Amended and Restated Bylaws of GeoMet, Inc. (incorporated herein by reference to Exhibit 3.1 to the Company s 8-K filed on November 13, 2007 (Registration No. 000-52155)).
4.1	Registration Rights Agreement between GeoMet, Inc. and Banc of America Securities LLC, dated as of January 30, 2006 (incorporated herein by reference to Exhibit 4.1 to the Company s Registration Statement on Form S-1 filed on February 10, 2006 (Registration No. 333-131716)).
10.1	2005 Stock Option Plan of GeoMet Inc., dated April 15, 2005 (incorporated herein by reference to Exhibit 10.2 to the Company s Registration Statement on Form S-1 filed on February 10, 2006 (Registration No. 333-131716)).
10.2	Form of Incentive Stock Option Agreement for the 2005 Stock Option Plan of GeoMet, Inc. (incorporated herein by reference to Exhibit 10.3 to the Company s Registration Statement on Form S-1 filed on February 10, 2006 (Registration No. 333-131716)).

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Exhibit No.	Description
10.3	Federal Income Tax Allocation Agreement among the Members of the GeoMet Resources, Inc. Consolidated Group, dated as of January 1, 2001 (incorporated herein by reference to Exhibit 10.4 to the Company s Registration Statement on Form S-1 filed on February 10, 2006 (Registration No. 333-131716)).
10.4	Incentive Bonus Pool Plan, dated as of May 29, 2001 (incorporated herein by reference to Exhibit 10.5 to the Company s Registration Statement on Form S-1 filed on February 10, 2006 (Registration No. 333-131716)).
10.5	Employment Agreement dated as of December 7, 2000 between GeoMet Resources, Inc. and William C. Rankin (incorporated herein by reference to Exhibit 10.6 to the Company s Registration Statement on Form S-1 filed on February 10, 2006 (Registration No. 333-131716)).
10.6	Employment Agreement dated as of December 7, 2000 between GeoMet Resources, Inc. and J. Darby Seré (incorporated herein by reference to Exhibit 10.7 to the Company s Registration Statement on Form S-1 filed on February 10, 2006 (Registration No. 333-131716)).
10.7	Third Amended and Restated Credit Agreement dated June 9, 2006, among GeoMet, Inc., Bank of America, N.A., as Administrative Agent, and BNP Paribas, as Syndication Agent (incorporated herein by reference to Exhibit 10.8 to the Company s Registration Statement on Form S-1 filed on June 21, 2006 (Registration No. 333-131716)).
10.8	GeoMet, Inc. 2006 Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.9 to the Company s Registration Statement on Form S-1 filed on May 12, 2006 (Registration No. 333-131716)).
10.9	Precedent Agreement dated March 28, 2006 between East Tennessee Natural Gas, LLC and GeoMet, Inc. (incorporated herein by reference to Exhibit 10.10 to the Company s Registration Statement on Form S-1 filed on May 12, 2006 (Registration No. 333-131716)) (portions of this exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment in accordance with Rule 406 under the Securities Act).
10.10	Option Agreement dated June 13, 2006 between Jon M. Gipson and GeoMet, Inc. (incorporated herein by reference to Exhibit 10.11 to the Company s Registration Statement on Form S-1 filed on June 21, 2006 (Registration No. 333-131716)).
10.11	Amendment No. 1 to 2006 Long-Term Incentive Plan dated effective as of March 13, 2007 (incorporated herein by reference to Exhibit 10.12 to the Company s 10-K filed on March 20, 2007 (Registration No. 000-52155)).
10.12	Amendment to Employment Agreement dated March 13, 2007 between GeoMet, Inc. and J. Darby Seré (incorporated herein by reference to Exhibit 10.13 to the Company s 10-K filed on March 20, 2007 (Registration No. 000-52155)).
10.13	Amendment to Employment Agreement dated March 13, 2007 between GeoMet, Inc. and William C. Rankin (incorporated herein by reference to Exhibit 10.14 to the Company s 10-K filed on March 20, 2007 (Registration No. 000-52155)).
10.14*	Employee Cash Bonus and Stock Award Retention Agreement dated November 9, 2007 between GeoMet, Inc. and Tony Oviedo.
10.15*	Second Amendment to Employment Agreement dated effective as of December 31, 2008 between GeoMet, Inc. and J. Darby Seré.
10.16*	Second Amendment to Employment Agreement dated effective as of December 31, 2008 between GeoMet, Inc. and William C. Rankin.

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Exhibit No.	Description
10.17	Stock Acquisition and Stockholders Agreement dated December 7, 2000 by and among GeoMet Resources, Inc., Yorktown Energy Partners IV, L.P., J. Darby Seré, and William C. Rankin (incorporated by reference to Exhibit 4.3 of the Company s Registration Statement on Form S-8, File No. 333-136924 filed on August 28, 2006).
10.18*	Form of Amended and Restated Non-Qualified Stock Option Agreement dated December 2, 2008.
10.19*	Form of Stock Option Award Agreement for the GeoMet, Inc. 2006 Long-Term Incentive Plan.
10.20*	Business Opportunities Agreement among GeoMet, Inc. and the other signatories thereto dated March 12, 2009.
14.1*	Corporate Code of Business Conduct and Ethics.
21.1*	List of Subsidiaries of GeoMet, Inc.
23.1*	Consent of Deloitte & Touche LLP
23.2*	Consent of Independent Petroleum Engineers DeGolyer and MacNaughton.
31.1*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith.

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SIGNATURES

In accordance with Section 13 or 15(d) of the Exchange Act, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on March 12, 2009.

GEOMET, INC.

By:	/s/ J. Darby Seré
Name:	**J. Darby Seré**
Title:	**President and Chief Executive Officer**

In accordance with the Exchange Act, this report has been signed below by the following persons on behalf of the registrants and in the capacities on March 12, 2009.

Signature	Capacity
/s/ J. Darby Seré **J. Darby Seré**	Chairman of the Board, President, Chief Executive Officer (Principal Executive Officer)
/s/ William C. Rankin **William C. Rankin**	Executive Vice President, Chief Financial Officer (Principal Financial Officer)
/s/ Tony Oviedo **Tony Oviedo**	Vice President, Chief Accounting Officer and Controller
/s/ J. Hord Armstrong, III **J. Hord Armstrong, III**	Director
/s/ James C. Crain **James C. Crain**	Director
/s/ Stanley L. Graves **Stanley L. Graves**	Director
/s/ Charles D. Haynes **Charles D. Haynes**	Director
/s/ W. Howard Keenan, Jr. **W. Howard Keenan, Jr.**	Director
/s/ Philip G. Malone	Director

Philip G. Malone

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INDEX TO EXHIBITS

Exhibit No.	Description
3.1	Form of Amended and Restated Certificate of Incorporation of GeoMet, Inc. (incorporated herein by reference to Exhibit 3.1 to the Company s Registration Statement on Form S-1 filed on July 25, 2006 (Registration No. 333-131716)).
3.2	Form Amended and Restated Bylaws of GeoMet, Inc. (incorporated herein by reference to Exhibit 3.1 to the Company s 8-K filed on November 13, 2007 (Registration No. 000-52155)).
4.1	Registration Rights Agreement between GeoMet, Inc. and Banc of America Securities LLC, dated as of January 30, 2006 (incorporated herein by reference to Exhibit 4.1 to the Company s Registration Statement on Form S-1 filed on February 10, 2006 (Registration No. 333-134070)).
10.1	2005 Stock Option Plan of GeoMet Inc., dated April 15, 2005 (incorporated herein by reference to Exhibit 10.2 to the Company s Registration Statement on Form S-1 filed on February 10, 2006 (Registration No. 333-134070)).
10.2	Form of Incentive Stock Option Agreement for the 2005 Stock Option Plan of GeoMet, Inc. (incorporated herein by reference to Exhibit 10.3 to the Company s Registration Statement on Form S-1 filed on February 10, 2006 (Registration No. 333-134070)).
10.3	Federal Income Tax Allocation Agreement among the Members of the GeoMet Resources, Inc. Consolidated Group, dated as of January 1, 2001 (incorporated herein by reference to Exhibit 10.4 to the Company s Registration Statement on Form S-1 filed on February 10, 2006 (Registration No. 333-134070)).
10.4	Incentive Bonus Pool Plan, dated as of May 29, 2001 (incorporated herein by reference to Exhibit 10.5 to the Company s Registration Statement on Form S-1 filed on February 10, 2006 (Registration No. 333-134070)).
10.5	Employment Agreement dated as of December 7, 2000 between GeoMet Resources, Inc. and William C. Rankin (incorporated herein by reference to Exhibit 10.6 to the Company s Registration Statement on Form S-1 filed on February 10, 2006 (Registration No. 333-134070)).
10.6	Employment Agreement dated as of December 7, 2000 between GeoMet Resources, Inc. and J. Darby Seré (incorporated herein by reference to Exhibit 10.7 to the Company s Registration Statement on Form S-1 filed on February 10, 2006 (Registration No. 333-134070)).
10.7	Third Amended and Restated Credit Agreement dated June 9, 2006, among GeoMet, Inc., Bank of America, N.A., as Administrative Agent, and BNP Paribas, as Syndication Agent (incorporated herein by reference to Exhibit 10.8 to the Company s Registration Statement on Form S-1 filed on June 21, 2006 (Registration No. 333-131716)).
10.8	GeoMet, Inc. 2006 Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.9 to the Company s Registration Statement on Form S-1 filed on May 12, 2006 (Registration No. 333-131716)).
10.9	Precedent Agreement dated March 28, 2006 between East Tennessee Natural Gas, LLC and GeoMet, Inc. (incorporated herein by reference to Exhibit 10.10 to the Company s Registration Statement on Form S-1 filed on May 12, 2006 (Registration No. 333-131716)) (portions of this exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment in accordance with Rule 406 under the Securities Act).

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10.11	Amendment No. 1 to 2006 Long-Term Incentive Plan dated effective as of March 13, 2007 (incorporated herein by reference to Exhibit 10.12 to the Company s 10-K filed on March 20, 2007 (Registration No. 000-52155)).
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23.1*	Consent of Deloitte & Touche LLP
23.2*	Consent of DeGolyer and MacNaughton.
31.1*	Certification of chief financial officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934.
31.2*	Certification of chief executive officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934.
32*	Certification pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith.