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

Registration No. 333-

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form S-1

REGISTRATION STATEMENT

UNDER

THE SECURITIES ACT OF 1933

GeoMet, Inc.

(Exact name of registrant as specified in its charter)

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

909 Fannin, Suite 3208

Houston, TX 77010

(713) 659-3855

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

J. Darby Seré

Chairman, President and Chief Executive Officer

GeoMet Inc.

909 Fannin, Suite 3208

Houston, TX 77010

(713) 659-3855

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

Copies to:

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(713) 654-8111

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

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

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

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

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

CALCULATION OF REGISTRATION FEE

Title of each class of Securities to be registered	Proposed maximum aggregate offering price (1)(2)	Amount of registration fee
Common stock, par value $0.001 per share	$ 160,000,000	$ 17,120

(1) Estimated solely for the purpose of calculating the registration fee under Rule 457(o) under the Securities Act.
(2) Includes common stock issuable upon exercise of the underwriters option to purchase additional shares of common stock.

The registrant hereby amends this registration statement on such date or dates as may be necessary to delay its effective date until the registrant shall file a further amendment which specifically states that this registration statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act or until this registration statement shall become effective on such date as the Commission, acting pursuant to said Section 8(a), may determine.

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The information in the prospectus is not complete and may be changed. We may not sell these securities until the registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell these securities, and it is not soliciting an offer to buy these securities in any jurisdiction where the offer or sale is not permitted.

Subject to Completion, Dated May 12, 2006

Prospectus

Shares

Common Stock

GeoMet, Inc. and the selling stockholders are offering shares and shares, respectively, of common stock. This is our initial public offering, and no public market currently exists for our shares. We anticipate that the initial public offering price will be between $ and $ per share. After the offering, the market price for our shares may be outside this range.

We intend to apply to have our common stock quoted on the Nasdaq National Market under the symbol .

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

	Per Share	Total
Offering price	$	$
Discounts and commissions to underwriters	$	$
Offering proceeds to GeoMet, Inc., before expenses	$	$
Offering proceeds to the selling stockholders	$	$

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

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

Banc of America Securities LLC

A.G. Edwards

Raymond James

, 2006

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WHERE YOU CAN FIND INFORMATION

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

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

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SUMMARY

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

About GeoMet

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

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

Areas of Operation

Cahaba Basin

We have the development rights to approximately 41,800 net CBM acres throughout the Cahaba Basin of central Alabama, which is adjacent to the Black Warrior Basin. At December 31, 2005, approximately 55% of our estimated proved reserves, or 145.1 Bcf, were located in the Gurnee field within the Cahaba Basin, of which approximately 78% were classified as proved developed. At December 31, 2005, we had developed 24% of our

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

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

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

Appalachian Basin

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

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

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

British Columbia

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

North Central Louisiana

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

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

Piceance Basin of Colorado

We hold a total of approximately 16,900 net CBM acres of leasehold in the Piceance Basin in Mesa County, Colorado, of which approximately 14,600 net CBM acres are located in our Cameo prospect in the southwestern portion of the Piceance Basin. We have drilled one core hole and have conducted desorption tests on the core. We believe that the gas content and coal thickness under our acreage position are favorable for CBM development. We are actively pursuing opportunities to increase our acreage position in this area.

Characteristics of Coalbed Methane

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

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

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

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Summary of Our Properties as of December 31, 2005

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

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

(1) Based on the reserve report prepared by DeGolyer and MacNaughton, independent petroleum engineers, a summary of which is attached to this prospectus as Appendix A.
(2) PV-10 was calculated using a natural gas price at December 31, 2005 of $9.66 per Mcf. See Selected Historical Consolidated Financial and Operating Data Reconciliation of Non-GAAP Financial Measures for additional information.
(3) Excludes nine net wells pending completion at December 31, 2005. Productive wells are wells in which we have a working interest and that are producing or are capable of producing natural gas.
(4) Additional known drilling locations in proved projects.

Recent Drilling Activity (net productive wells)

	Year Ended December 31, 2005(1)	2004	2003	2002

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

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

Strategy

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

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

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

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

Seek out opportunistic CBM producing property acquisitions.

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

Competitive Strengths

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

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

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

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

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

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

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

1977.

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

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

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

Risks Affecting Our Business

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

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CORPORATE INFORMATION

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

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

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

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THE OFFERING

Common stock offered by us(1)	shares.
Common stock offered by the selling stockholders	shares.
Common stock to be outstanding after this offering(1)(2)(3)	shares.
Use of proceeds	We will receive net proceeds from the sale of the shares offered by us, after deducting estimated offering expenses and underwriting discounts and commissions, of approximately $ million, based on an assumed offering price of $ per share. We expect to use our net proceeds from this offering to repay $ million of outstanding indebtedness under our credit facility and to use the remainder for general corporate purposes. We will not receive any proceeds from the sale of shares of our common stock by the selling stockholders.
Dividend policy	We do not anticipate that we will pay cash dividends in the foreseeable future. Our credit facility prohibits the payment of cash dividends.
Risk factors	For a discussion of factors you should consider in making an investment, see Risk Factors.
Proposed Nasdaq symbol	

(1) We have granted the underwriters an option to purchase up to additional shares of our common stock if the underwriters sell more than shares of common stock in this offering. Unless otherwise indicated, share numbers assume that the underwriters do not exercise their option to purchase additional shares of common stock.
(2) Excludes options to purchase 1,770,990 shares of our common stock outstanding as of March 31, 2006, of which 1,682,990 were exercisable within 60 days.
(3) Represents 32,614,021 shares outstanding on March 31, 2006 and the shares to be issued in this offering.

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SUMMARY OF FINANCIAL, RESERVE AND OPERATING DATA

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

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

PV-10 ($ millions)(2)(3)	$ 880.2	$ 481.8	$ 236.9
Standardized measure of discounted future net cash flows ($ millions)	$ 632.7	$ 349.8	$ 172.5
Price used for PV-10 ($ per Mcf)(2)	$ 9.66	$ 6.21	$ 5.77
EBITDA (in millions)(3)	$ 6.1	$ 9.8	$ 6.5

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

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

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

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RISK FACTORS

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

Risks Related To Our Business

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Our exploration and development activities may not be commercially successful.

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

- unexpected drilling conditions;

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

We may face unanticipated water disposal costs.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Hedging transactions may limit our potential gains.

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

- our production is less than expected; or

- the counterparties to our hedging agreements fail to perform under the contracts.

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

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

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

Risks Relating to Our Common Stock

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

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

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

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

- our operating and financial performance and prospects;
- quarterly variations in the rate of growth of our financial indicators, such as net income per share, net income and revenues;
- changes in revenue or earnings estimates or publication of research reports by analysts about us or the exploration and production industry;
- liquidity and registering our common stock for public resale;

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

changes in oil and gas prices;

speculation in the press or investment community;

sales of our common stock by our stockholders;

increases in our cost of capital;

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

changes in market valuations of similar companies;

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

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

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

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

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

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

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

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

We may in the future issue our previously authorized and unissued securities, resulting in the dilution of the ownership interests of our present stockholders and purchasers of common stock offered hereby. Our authorized capital stock consists of 125,000,000 shares of common stock and 10,000,000 shares of preferred stock with such designations, preferences, and rights as may determined by our board of directors. As of March 31, 2006,

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

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

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

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CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

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

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

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

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

competition in the gas industry;

our inability to retain and attract key personnel;

our joint venture arrangements;

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

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

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

other factors discussed under Risk Factors.

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USE OF PROCEEDS

We expect to receive net proceeds from this offering of approximately $ million ($ million if the underwriters option to purchase additional shares is exercised in full), based on an assumed public offering price of $ per share (the midpoint of the price range set forth on the cover page of this prospectus) and after deducting underwriting discounts and commissions and estimated offering expenses of $ incurred by us. We will not receive any of the proceeds from the sale of shares of our common stock by the selling stockholders.

We expect to use our net proceeds from this offering to repay $ million of outstanding indebtedness under our credit facility and to use the remainder for general corporate purposes.

DIVIDEND POLICY

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

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CAPITALIZATION

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

a historical basis;

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

a pro forma as adjusted basis to give effect to the sale of shares in this offering and the application of the net proceeds we receive as set forth under Use of Proceeds.

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

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

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

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

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

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DILUTION

If you invest in our common stock, your interest will be diluted to the extent of the difference between the public offering price per share and the pro forma net tangible book value per share of the common stock after this offering. Our net tangible book value as of December 31, 2005, on a pro forma basis giving effect to our private placement of 2,317,023 shares of our common stock during the first quarter of 2006, the issuance of 192,020 shares from the exercise of stock options, and a four-four-one common stock split in January 2006, was $ per share of common stock. Pro forma net tangible book value per share represents the amount of the total pro forma tangible assets less our total pro forma liabilities, divided by the pro forma number of shares of common stock that are outstanding. After giving effect to the sale of shares of common stock in this offering and our private placement during the first quarter of 2006 at an assumed offering price of $ per share and after the deduction of underwriting discounts and commissions and estimated offering expenses, the pro forma as adjusted net tangible book value at December 31, 2005 would have been $ million, or $ per share. This represents an immediate increase in such net tangible book value of $ per share to existing stockholders and an immediate and substantial dilution of $ per share to new investors purchasing common stock in this offering. The following table illustrates this per share dilution:

Assumed offering price per share		$
Net tangible book value per share as of December 31, 2005	$	
Increase attributable to new public investors	$	
As adjusted net tangible book value per share after this offering		$
Dilution in as adjusted net tangible book value per share to new investors		$

Assuming the exercise in full of the underwriters option to purchase additional shares, our pro forma as adjusted net tangible book value at December 31, 2005 would have been approximately $ per share, representing an immediate increase in the pro forma net tangible book value of $ per share to our existing stockholders and an immediate decrease in pro forma net tangible book value of $ per share to new investors.

The following table summarizes, on a pro forma as adjusted basis, as of December 31, 2005, the difference between the number of shares of common stock purchased from us, the total consideration paid to us and the average price per share paid by existing stockholders and by new investors at an assumed initial public offering price of $ per share, before deducting estimated underwriting discounts and commissions and estimated offering expenses.

	Shares Purchased		Total Consideration		Average Price Per Share
	Number	Percent	Amount	Percent	
Existing stockholders		%	$	%	$
New investors					
Total		100.0%	$	100.0%	

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SELECTED HISTORICAL CONSOLIDATED FINANCIAL AND OPERATING DATA

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

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

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

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SELECTED HISTORICAL CONSOLIDATED FINANCIAL AND OPERATING DATA (continued):

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

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

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

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

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Reconciliation of Non-GAAP Financial Measures

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

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

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

	Year Ended December 31,				
	2005	2004	2003	2002	2001

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

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MANAGEMENT S DISCUSSION AND ANALYSIS OF

RESULTS OF OPERATIONS AND FINANCIAL CONDITION

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

Overview

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

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

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

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

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

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

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

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

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

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

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

Critical Accounting Policies

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Estimating the amount of valuation allowance is dependent on estimates of future taxable income, alternative minimum tax income, and changes in stockholder ownership that could trigger limits on use of net operating losses under Internal Revenue Code Section 382. We have a significant deferred tax asset associated

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with net operating loss carryforwards (NOLs). It is more likely than not that we will use these NOLs to offset current tax liabilities in future years.

Future Charges

Public Company Expenses

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

Stock Compensation

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

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

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

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

The effects of applying SFAS 123 in this pro forma disclosure may not be representative of future amounts. See Note 9 to our consolidated financial statements included elsewhere in this prospectus for additional detail on stock options. The fair value of each option grant was based on the minimum value method with the following assumptions used for grants for the years ended December 31, 2005, 2004 and 2003: (a) dividend yield of 0%, (b) expected volatility of 0%, (c) risk-free interest rate of 3.4% in 2005, 2.6% in 2004, and 2.5% in 2003, and (d) an expected life of three years for 2005 and 2004, and four years for 2003.

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

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

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

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

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

the most recent valuation of our estimated proved natural gas reserves prepared by independent reservoir engineers;

the future price of natural gas;

the relative risks associated with estimating production and costs from different categories of reserves;

the discount factor used to approximate the time value of money;

the significant uncertainty surrounding the determination of estimated quantities of natural gas reserves;

the valuation of other assets and liabilities;

arms-length transactions involving our common stock; and

general industry and economic trends.

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

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

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

Increases in the quantities of proved reserves owned by us and increases in the level of daily production volume resulting from our ongoing successful drilling program at Gurnee and Pond Creek. Quantities of

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proved reserves increased 13 Bcf, or 6.2%, from 210 Bcf at December 31, 2004 to 213 Bcf at June 30, 2005. Quantities of proved reserves further increased 50 Bcf, or 23.5%, from June 30, 2005 to 263 Bcf at December 31, 2005; and

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

Derivative Instruments

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

Producing Field Operations Summary

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

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

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

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

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Results of Operations

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Liquidity and Capital Resources

Cash Flows and Liquidity

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

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

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

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

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

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

Price Risk Management Activities

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

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

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

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

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

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

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

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

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

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

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

Capital Expenditures and Capital Resources

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

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

Credit Facility

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

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

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

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

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

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

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

Contractual Commitments

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

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

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

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

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

Off-Balance Sheet Arrangements

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

Recent Accounting Pronouncements

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

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

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

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

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

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

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

Quantitative and Qualitative Disclosures about Market Risk

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

Foreign Currency Exchange Rate Risk

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

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BUSINESS

About GeoMet

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

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

Areas of Operation

Cahaba Basin

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

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

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

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

Appalachian Basin

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

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

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

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

British Columbia

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

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

North Central Louisiana

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

Piceance Basin of Colorado

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

History of GeoMet

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

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

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

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

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

Estimated Proved Reserves

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

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

PV-10, a non-GAAP measure, is our estimated present value of future net revenues from estimated proved reserves before income taxes. We believe PV-10 to be an important measure for evaluating the relative significance of our CBM gas properties and that PV-10 is widely used by professional analysts and investors in evaluating gas companies. Because many factors that are unique to each individual company impact the amount of future income taxes to be paid, the use of a pre-tax measure provides greater comparability of assets when evaluating companies. We believe that most other companies in the oil and gas industry calculate PV-10 on the same basis. Management also uses PV-10 in evaluating acquisition candidates. PV-10 only differs from the standardized measure of discounted future net cash flows (SMOG), as calculated and presented in accordance with SFAS No. 69, in that SMOG takes into account the present value of income taxes related to our net cash flows. See Selected Historical Consolidated Financial and Operating Data Reconciliation of Non-GAAP Financial Measures.

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

CBM gas estimates and for certain additional information concerning the estimated proved reserves.

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

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Historical Finding and Development Costs

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

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

Production and Operating Statistics

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

	Year Ended December 31,		
	2005	**2004**	**2003**
Gas:			
Net sales volume (Bcf)	4.6	3.2	2.5
Average natural gas sales price ($ per Mcf)	$ 9.06	$ 6.12	$ 4.71
Average natural gas sales price ($ per Mcf) realized (1)	$ 7.43	$ 5.87	$ 4.69
Total production expenses ($ per Mcf)	$ 2.81	$ 2.36	$ 1.23
Expenses: ($ per Mcf)			
Lease operations expenses	$ 1.89	$ 1.60	$ 0.66
Compression and transportation expenses	$ 0.72	$ 0.61	$ 0.40
Production taxes	$ 0.20	$ 0.15	$ 0.17
Depreciation, depletion & amortization (excluding impairment)	$ 1.06	$ 0.84	$ 0.85
Research and development	$ 0.13	$ 0.09	$ 0.17
General and administrative	$ 0.70	$ 0.79	$ 0.55

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

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Productive Wells and Acreage

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

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

(1) Excludes 9 gross/net wells pending completion at December 31, 2005.

Drilling Activity

The following table sets forth the number of completed gross exploratory and gross development wells drilled in the United States and Canada that we participated in for each of the last three fiscal years. The number of wells drilled refers to the number of wells commenced at any time during the respective year. Productive wells are producing wells and wells capable of production. At December 31, 2005, we were in the process of completing 9 gross wells (9 net).

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

	Exploratory			Development		
Well Activity (Gross) Canada	**Productive**	**Dry**	**Total**	**Productive**	**Dry**	**Total**

Year ended December 31, 2005	2		2			

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

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

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

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Title to Properties

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

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

Marketing and Customers

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

Competition

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

Regulation

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

the certification and construction of new facilities;

the extension or abandonment of services and facilities;

the maintenance of accounts and records;

the acquisition and disposition of facilities;

the initiation and discontinuation of services; and

various other matters.

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

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

Gathering Pipeline Regulation. Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of the FERC. We own an intrastate natural gas pipeline that we believe would meet the traditional tests the FERC has used to establish a pipeline s status as a gatherer not subject to the FERC jurisdiction. However, the distinction between the FERC-regulated transmission services and federally unregulated gathering services is the subject of regular litigation, so, in such a circumstance, the classification and regulation of some of our gathering facilities may be subject to change based on future determinations by the FERC and the courts.

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

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

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

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Environmental Regulations

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

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

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

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

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

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

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

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

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

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

In addition, our operations may in the future be subject to the regulation of greenhouse gas emissions. Numerous countries, including Canada but not the United States, are participants in the Kyoto Protocol to the United Nations Framework Convention on Climate Change. Participating countries are required to implement national programs to reduce emissions of certain gases, generally referred to as greenhouse gases, that are suspected of contributed to global warming. Although the United States is not participating in the Protocol, there has been support in various regions of the country for legislation that requires reductions in greenhouse gas

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emissions, and some states have already adopted legislation addressing greenhouse gas emissions from certain greenhouse gas emission sources, primarily power plants. The oil and gas exploration and production industry is a direct source of certain greenhouse gas emissions, namely carbon dioxide and methane, and future restrictions on such emissions could impact our future operations. Our operations in the United States currently are not adversely impacted by current state and local climate change initiatives. Our Canadian operations are subject to the Protocol, but implementation of the Protocol s greenhouse gas emission reduction requirements in British Columbia are not presently expected to have a significant adverse effect on our operations. However, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions may impact our business.

Employees

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

Legal Proceedings

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

El Paso Overriding Royalty Interest Dispute

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

Insurance Matters

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

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MANAGEMENT

Executive Officers and Directors

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

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

J. Darby Seré, *Chairman of the Board, President, and Chief Executive Officer.* Since 2000, Mr. Seré has served as a Director, President and Chief Executive Officer of GeoMet, Inc. Mr. Seré was elected Chairman of the Board in January 2006. Mr. Seré has over 34 years of experience in the oil and gas business, including 17 years as Chief Executive Officer of two publicly held exploration and production companies. Mr. Seré served as President, CEO and Director of Bellwether Exploration Company from 1988-1999, where he also served as Chairman of the Board from 1997-1999, and President, Chief Executive Officer and Director of Bayou Resources, Inc. from 1982-1987. Mr. Seré was Manager of Acquisitions, Vice President Acquisitions and Engineering and Executive Vice President of Howell Corporation / Howell Petroleum Corporation from 1977-1981. Mr. Seré began his career as a staff reservoir engineer for Chevron Oil Co. in 1970. Mr. Seré currently serves as a director of Gateway Energy Corporation, a publicly held gas gathering, transportation and distribution company. Mr. Seré is a registered professional engineer and holds a Bachelors degree in Petroleum Engineering from Louisiana State University and a Masters of Business Administration from Harvard University.

William C. Rankin, *Executive Vice President and Chief Financial Officer.* Since 2000, Mr. Rankin has served as Executive Vice President and Chief Financial Officer of GeoMet, Inc. Mr. Rankin has 34 years experience as an accountant and financial manager, including 27 years as a financial officer with both publicly and privately owned energy companies. He began his career as an auditor with Deloitte & Touche from 1971-1975. He served as Director of Internal Audit of Kerr-McGee Corporation from 1975-1977, Controller of Cotton Petroleum Corporation from 1977-1980 and Executive Vice President and Chief Financial Officer for Cayman Resources Corporation from 1980-1985. Mr. Rankin joined Hadson Corporation in 1985 as Vice President and Controller, became Vice President and Treasurer in 1988 and last served as Sr. Vice President and Chief Financial Officer of Hadson Resources Corporation from 1989-1993. In 1994 he became Sr. Vice President and Chief Financial Officer of Contour Energy Company (and its predecessors) where he served until 1997. In 1997, he became Sr. Vice President of Bellwether Exploration Company. Mr. Rankin is a Certified Public Accountant and holds a Bachelors degree in Accounting from the University of Arkansas.

Philip G. Malone, *Senior Vice President Exploration and Director.* Since 2000, Mr. Malone has served as our Vice President Exploration. Mr. Malone has 31 years experience as a professional geologist; one year at the Geological Survey of Alabama, ten years at USX Corporation and 20 years at GeoMet, where he participated inop:0px;margin-bottom:-6px">

- in compliance with a condition imposed by any such court or authority permitting Wachovia s acquisition of any other bank or entity; or

- in compliance with an undertaking made to such authority in connection with such an acquisition; provided, in the case of the two preceding bullet-points, the assets of the bank or entity being acquired and its consolidated subsidiaries equal or exceed 75% of the assets of such Major Subsidiary Bank or such subsidiary owning, directly or indirectly, any shares of voting stock of a Major Subsidiary Bank and its respective consolidated subsidiaries on the date of acquisition; or

- to Wachovia or any wholly-owned subsidiary.

Despite the above requirements, any Major Subsidiary Bank may be merged into or consolidated with another banking institution organized under U.S. or state law, if after giving effect to that merger or consolidation Wachovia or any wholly-owned subsidiary owns at least 80% of the voting stock of the other banking institution free and clear of any security interest and if, immediately after the merger or consolidation, no event of default, and no event which, after notice or lapse of time or both, would become an event of default, shall have happened and be continuing. (*Section 1007*) A Major Subsidiary Bank is defined in each indenture to mean any subsidiary which is a bank and has total assets equal to 25% or more of Wachovia s consolidated assets determined on the date of the most recent audited financial statements of these entities. At present, the Major Subsidiary Bank is Wachovia Bank, National Association.

The above covenant is not a covenant for the benefit of any series of debt securities issued before August 1, 1990, or, in the case of subordinated debt securities including the subordinated notes, issued after November 15, 1992.

Form, Exchange and Transfer

If the notes cease to be issued in global form, they will be issued:

- only in fully registered form;

- without interest coupons; and

- unless we indicate otherwise in your pricing supplement, in denominations of $1,000 and that are multiples of $1,000.

Holders may exchange their notes for notes of smaller denominations or combined into fewer notes of larger denominations, as long as the total principal amount is not changed.

Holders may exchange or transfer their notes at the office of the relevant trustee, or in the event definitive notes are issued and so long as the notes are listed on the Luxembourg Stock Exchange, at the offices of the paying agent. We have appointed the respective trustees to act as our agents for registering notes in the names of holders and transferring notes. We may appoint another entity to perform these functions or perform them ourselves.

Holders will not be required to pay a service charge to transfer or exchange their notes, but they may be required to pay for any tax or other governmental charge associated with the exchange or transfer. The

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transfer or exchange will be made only if our transfer agent is satisfied with the holder s proof of legal ownership.

If we have designated additional transfer agents for your note, they will be named in your pricing supplement. We may appoint additional transfer agents or cancel the appointment of any particular transfer agent. We may also approve a change in the office through which any transfer agent acts.

If any notes are redeemable and we redeem less than all those notes, we may block the transfer or exchange of those notes during the period beginning 15 days before the day we mail the notice of redemption and ending on the day of that mailing, in order to freeze the list of holders to prepare the mailing. We may also refuse to register transfers of or exchange any note selected for redemption, except that we will continue to permit transfers and exchanges of the unredeemed portion of any note being partially redeemed.

If a note is issued as a global note, only the depositary e.g., DTC, Euroclear and Clearstream will be entitled to transfer and exchange the note as described in this subsection, since it will be the sole holder of the note.

Payment Mechanics

Who Receives Payment?

If interest is due on a note on an interest payment date, we will pay the interest to the person or entity in whose name the note is registered at the close of business on the regular record date relating to the interest payment date. If interest is due at maturity but on a day that is not an interest payment date, we will pay the interest to the person or entity entitled to receive the principal of the note. If principal or another amount besides interest is due on a note at maturity, we will pay the amount to the holder of the note against surrender of the note at a proper place of payment (or, in the case of a global note, in accordance with the applicable policies of the depositary).

How We Will Make Payments Due in U.S. Dollars

We will follow the practice described in this subsection when paying amounts due in U.S. dollars. Payments of amounts due in other currencies will be made as described in the next subsection.

Payments on Global Notes. We will make payments on a global note in accordance with the applicable policies of the depositary as in effect from time to time. Under those policies, we will pay directly to the depositary, or its nominee, and not to any indirect holders who own beneficial interests in the global note. An indirect holder s right to receive those payments will be governed by the rules and practices of the depositary and its participants, as described under Global Notes and Global Notes .

Payments on Non-Global Notes. We will make payments on a note in non-global form as follows. We will pay interest that is due on an interest payment date by check mailed on the interest payment date to the holder at his or her address shown on the trustee s records as of the close of business on the regular record date. We will make all other payments by check at the paying agent described below, against surrender of the note. All payments by check will be made in next-day funds i.e., funds that become available on the day after the check is cashed.

Alternatively, if a non-global note has a face amount of at least $1,000,000 and the holder asks us to do so, we will pay any amount that becomes due on the note by wire transfer of immediately available funds to an account at a bank in New York City, on the due date. To request wire payment, the holder must give the paying agent appropriate wire transfer instructions at least five business days before the requested wire payment is due. In the case of any interest payment due on an interest payment date, the instructions must be given by the person or entity who is the holder on the relevant regular record date. In the case of any other

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payment, payment will be made only after the note is surrendered to the paying agent. Any wire instructions, once properly given, will remain in effect unless and until new instructions are given in the manner described above.

Book-entry and other indirect holders should consult their banks or brokers for information on how they will receive payments on their notes.

How We Will Make Payments Due In Other Currencies

We will follow the practice described in this subsection when paying amounts that are due in a specified currency other than U.S. dollars.

Payments on Global Notes. We will make payments on a global note in accordance with the applicable policies as in effect from time to time of the depositary, which will be DTC, Euroclear or Clearstream. Unless we specify otherwise in the applicable pricing supplement, DTC will be the depositary for all notes in global form. We understand that DTC s policies, as currently in effect, are as follows.

Unless otherwise indicated in your pricing supplement, if you are an indirect holder of global notes denominated in a specified currency other than U.S. dollars and if you elect to receive payments in that other currency, you must notify the participant through which your interest in the global note is held of your election:

- on or before the applicable regular record date, in the case of a payment of interest, or
- on or before the 16th day prior to stated maturity, or any redemption or repayment date, in the case of payment of principal or any premium.

You may elect to receive all or only a portion of any interest, principal or premium payment in a specified currency other than U.S. dollars.

Your participant must, in turn, notify DTC of your election on or before the third DTC business day after that regular record date, in the case of a payment of interest, and on or before the 12th DTC business day prior to stated maturity, or on the redemption or repayment date if your note is redeemed or repaid earlier, in the case of a payment of principal or any premium.

DTC, in turn, will notify the paying agent of your election in accordance with DTC s procedures.

If complete instructions are received by the participant and forwarded by the participant to DTC, and by DTC to the paying agent, on or before the dates noted above, the paying agent, in accordance with DTC s instructions will make the payments to you or your participant by wire transfer of immediately available funds to an account maintained by the payee with a bank located in the country issuing the specified currency or in another jurisdiction acceptable to us and the paying agent.

If the foregoing steps are not properly completed, we expect DTC to inform the paying agent that payment is to be made in U.S. dollars. In that case, we or our agent will convert the payment to U.S. dollars in the manner described below under Conversion to U.S. Dollars . We expect that we or our agent will then make the payment in U.S. dollars to DTC, and that DTC in turn will pass it along to its participants.

Indirect holders of a global note denominated in a currency other than U.S. dollars should consult their banks or brokers for information on how to request payment in the specified currency.

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Payments on Non-Global Notes. Except as described in the last paragraph under this heading, we will make payments on notes in non-global form in the applicable specified currency. We will make these payments by wire transfer of immediately available funds to any account that is maintained in the applicable specified currency at a bank designated by the holder and is acceptable to us and the trustee. To designate an account for wire payment, the holder must give the paying agent appropriate wire instructions at least five business days before the requested wire payment is due. In the case of any interest payment due on an interest payment date, the instructions must be given by the person or entity who is the holder on the regular record date. In the case of any other payment, the payment will be made only after the note is surrendered to the paying agent. Any instructions, once properly given, will remain in effect unless and until new instructions are properly given in the manner described above.

If a holder fails to give instructions as described above, we will notify the holder at the address in the trustee s records and will make the payment within five business days after the holder provides appropriate instructions. Any late payment made in these circumstances will be treated under the indenture as if made on the due date, and no interest will accrue on the late payment from the due date to the date paid.

Although a payment on a note in non global form may be due in a specified currency other than U.S. dollars, we will make the payment in U.S. dollars if the holder asks us to do so. To request U.S. dollar payment, the holder must provide appropriate written notice to the trustee at least five business days before the next due date for which payment in U.S. dollars is requested. In the case of any interest payment due on an interest payment date, the request must be made by the person or entity who is the holder on the regular record date. Any request, once properly made, will remain in effect unless and until revoked by notice properly given in the manner described above.

Book-entry and other indirect holders of a note with a specified currency other than U.S. dollars should contact their banks or brokers for information about how to receive payments in the specified currency or in U.S. dollars.

Conversion to U.S. Dollars. When we are asked by a holder to make payments in U.S. dollars of an amount due in another currency, either on a global note or a non-global note as described above, the exchange rate agent described below will calculate the U.S. dollar amount the holder receives in the exchange rate agent s discretion.

A holder that requests payment in U.S. dollars will bear all associated currency exchange costs, which will be deducted from the payment.

When the Specified Currency is Not Available. If we are obligated to make any payment in a specified currency other than U.S. dollars, and the specified currency or any successor currency is not available to us due to circumstances beyond our control such as the imposition of exchange controls or a disruption in the currency markets we will be entitled to satisfy our obligation to make the payment in that specified currency by making the payment in U.S. dollars, on the basis of the exchange rate determined by the exchange rate agent described below, in its discretion.

The foregoing will apply to any note, whether in global or non-global form, and to any payment, including a payment at maturity. Any payment made under the circumstances and in a manner described above will not result in a default under any note or the relevant indenture.

Exchange Rate Agent. If we issue a note in a specified currency other than U.S. dollars, we will appoint a financial institution to act as the exchange rate agent and will name the institution initially appointed when the note is originally issued in the applicable pricing supplement. We may select Wachovia Bank, National Association or another of our affiliates to perform this role. We may change the exchange rate agent from time to time after the original issue date of the note without your consent and without notifying you of the change.

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All determinations made by the exchange rate agent will be at its sole discretion unless we state in the applicable pricing supplement that any determination requires our approval. In the absence of manifest error, those determinations will be conclusive for all purposes and binding on you and us, without any liability on the part of the exchange rate agent.

Payment When Offices Are Closed

If any payment is due on a note on a day that is not a business day, we will make the payment on the next day that is a business day. Payments postponed to the next business day in this situation will be treated under the relevant indenture as if they were made on the original due date. Postponement of this kind will not result in a default under any note or the indenture, and no interest will accrue on the postponed amount from the original due date to the next day that is a business day. The term business day has a special meaning, which we describe above under Interest Rates Special Rate Calculation Terms .

Paying Agent

We may appoint one or more financial institutions to act as our paying agents, at whose designated offices notes in non-global entry form may be surrendered for payment at their maturity. We call each of those offices a paying agent. We may add, replace or terminate paying agents from time to time. We may also choose to act as our own paying agent. Initially, we have appointed Wachovia Bank, National Association, at its corporate trust office in New York City or its headquarters in Charlotte, North Carolina, as the paying agent. We must notify you of changes in the paying agents.

Citibank, N.A., acting through its London office (or such other agent appointed in accordance with the Senior Indenture or the Subordinated Indenture, as the case may be), will act as London paying agent and London issuing agent.

In the event definitive notes are issued as described in this prospectus and as long as the notes are listed on the Luxembourg Stock Exchange, the holders of those notes will be able to receive payments and effect transfers at the offices of Dexia Banque Internationale à Luxembourg, Luxembourg or its successor as paying agent in Luxembourg relating to the notes. Each indenture provides for the replacement of a mutilated, lost, stolen or destroyed definitive note, so long as the applicant furnishes to Wachovia and the relevant trustee the security or indemnity required by them to save each of them harmless and any evidence of ownership of the note as they may require.

Dexia Banque Internationale à Luxembourg will act as a paying agent and transfer agent in Luxembourg in relation to the notes, and as long as the notes are listed on the Luxembourg Stock Exchange, Wachovia will maintain a paying agent and transfer agent in Luxembourg and any change in the Luxembourg paying agent and transfer agent will be published in Luxembourg in accordance with the second paragraph below under Notices .

Unclaimed Payments

Regardless of who acts as paying agent, all money paid by us to a paying agent that remains unclaimed at the end of two years after the amount is due to a holder will be repaid to us. After that two-year period, the holder may look only to us for payment and not to the relevant trustee, any other paying agent or anyone else.

Notices

Notices to be given to holders of a global note will be given only to the depositary, in accordance with its applicable policies as in effect from time to time. Notices to be given to holders of notes not in global form will be sent by mail to the respective addresses of the holders as they appear in the relevant trustee s records, and will be deemed given when mailed.

As long as the notes are listed on the Luxembourg Stock Exchange and its rules require, we will also give notices to holders by publication in a daily newspaper of general circulation in Luxembourg. We expect that newspaper to be, but it need not be, the *Luxemburger Wort*. If publication in Luxembourg is not practical, we will make the publication elsewhere in Western Europe. By daily newspaper we mean a newspaper that is published on each day, other than a Saturday, Sunday or holiday, in Luxembourg or, when applicable, elsewhere in Western Europe. You will be presumed to have received these notices on the date we first publish them. If we are unable to give notice as described in this paragraph because the publication of any newspaper is suspended or it is otherwise impracticable for us to publish the notice, then we or the relevant trustee, acting on our instructions, will give holders notice in another form. That alternate form of notice will be sufficient notice to you.

Neither the failure to give any notice to a particular holder, nor any defect in a notice given to a particular holder, will affect the sufficiency of any notice given to another holder.

Book-entry and other indirect holders should consult their banks or brokers for information on how they will receive notices.

Trustees

Either or both of the trustees may resign or be removed with respect to one or more series of notes and a successor trustee may be appointed to act with respect to that series. (*Section 610*) In the event that two or more persons are acting as trustee with respect to different series of notes, each such trustee shall be a trustee of a trust under the relevant indenture separate and apart from the trust administered by any other such trustee (*Section 611*), and any action to be taken by the trustee may then be taken by each such trustee with respect to, and only with respect to, the one or more series of notes for which it is trustee.

In the normal course of business, Wachovia and its subsidiaries conduct banking transactions with the trustees and their affiliates, and the trustees and their affiliates conduct banking transactions with Wachovia and its subsidiaries.

Title

Wachovia, the trustees and any of their agents may treat the registered owner of any note as the absolute owner of that security, whether or not that note is overdue and despite any notice to the contrary, for any purpose. See Global Notes .

Governing Law

The indentures and the notes will be governed by New York law.

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GLOBAL NOTES

We will issue each note in book-entry form only. Each note issued in book-entry form will be represented by a global note that we deposit with and register in the name of one or more financial institutions or clearing systems, or their nominees, which we select. A financial institution or clearing system that we select for this purpose is called the depositary for that note. A note will usually have only one depositary but it may have more.

Each series of notes will have one or more of the following as the depositaries.

The Depository Trust Company, New York, New York, which is known as DTC ;

JPMorgan Chase Bank, N.A. holding the notes on behalf of Euroclear Bank S.A./N.V., as operator of the Euroclear system, which is known as Euroclear ;

Citibank, N.A. holding the notes on behalf of Clearstream Banking, société anonyme, Luxembourg, which is known as Clearstream ; and

any other clearing system or financial institution named in the applicable pricing supplement.

The depositaries named above may also be participants in one another s system. Thus, for example, if DTC is the depositary for a global note, investors may hold beneficial interests in that note through Euroclear or Clearstream, as DTC participants. The depositary or depositaries for your notes will be named in your pricing supplement; if none is named, the depositary will be DTC.

A global note may not be transferred to or registered in the name of anyone other than the depositary or its nominee, unless special termination situations arise. We describe those situations below under Holder s Option to Obtain a Non-Global Note; Special Situations When a Global Note Will Be Terminated . As a result of these arrangements, the depositary, or its nominee, will be the sole registered owner and holder of all notes represented by a global note, and investors will be permitted to own only indirect interests in a global note. Indirect interests must be held by means of an account with a broker, bank or other financial institution that in turn has an account with the depositary or with another institution that does. Thus, an investor whose note is represented by a global note will not be a holder of the note, but only an indirect owner of an interest in the global note.

If the pricing supplement for a particular note indicates that the note will be issued in global form only, then the note will be represented by a global note at all times unless and until the global note is terminated. We describe the situations in which this can occur below under Holder s Option to Obtain a Non-Global Note; Special Situations When a Global Note Will Be Terminated . If termination occurs, we may issue the notes through another book-entry clearing system or decide that the notes may no longer be held through any book-entry clearing system.

DTC has informed Wachovia that it is a limited-purpose trust company organized under the New York Banking Law, a banking organization within the meaning of the New York Banking Law, a member of the Federal Reserve System, a clearing corporation within the meaning of the New York Uniform Commercial Code, and a clearing agency registered pursuant to the provisions of Section 17A of the Exchange Act. DTC holds securities that DTC participants deposit with DTC. DTC also facilitates the settlement among DTC participants of securities transactions, such as transfers and pledges, in deposited securities through electronic computerized book-entry changes in DTC participants accounts, thereby eliminating the need for physical movement of certificates. DTC participants include securities brokers and dealers, banks, trust companies and clearing corporations, and may include other organizations. DTC is owned by a number of its direct participants and by the New York Stock Exchange, Inc., the American Stock Exchange, LLC and the National Association of Securities Dealers, Inc. Indirect access to the DTC system also is available to others such as banks, brokers, dealers and trust companies that clear through or maintain a custodial relationship with a participant, either directly or indirectly. The rules applicable to DTC and DTC participants are on file with the Commission.

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Special Considerations for Global Notes

As an indirect owner, an investor s rights relating to a global note will be governed by the account rules of the depositary and those of the investor s financial institution or other intermediary through which it holds its interest (e.g., Euroclear or Clearstream, if DTC is the depositary), as well as general laws relating to note transfers. We do not recognize this type of investor or any intermediary as a holder of notes and instead deal only with the depositary that holds the global note.

If notes are issued only in the form of a global note, an investor should be aware of the following:

- An investor cannot cause the notes to be registered in his or her own name, and cannot obtain non-global certificates for his or her interest in the notes, except in the special situations we describe below;
- An investor will be an indirect holder and must look to his or her own bank or broker for payments on the notes and protection of his or her legal rights relating to the note, as we describe above under Description of the Notes We May Offer Legal Ownership ;
- An investor may not be able to sell interests in the notes to some insurance companies and other institutions that are required by law to own their notes in non-book-entry form;
- An investor may not be able to pledge his or her interest in a global note in circumstances where certificates representing the notes must be delivered to the lender or other beneficiary of the pledge in order for the pledge to be effective;
- The depositary s policies will govern payments, deliveries, transfers, exchanges, notices and other matters relating to an investor s interest in a global note, and those policies may change from time to time. We and the relevant trustee will have no responsibility for any aspect of the depositary s policies, actions or records or ownership interests in a global note. We and the trustees also do not supervise the depositary in any way;
- The depositary will require that those who purchase and sell interests in a global note within its book-entry system use immediately available funds and your broker or bank may require you to do so as well; and
- Financial institutions that participate in the depositary s book-entry system and through which an investor holds its interest in the global notes, directly or indirectly, may also have their own policies affecting payments, deliveries, transfers, exchanges, notices and other matters relating to the notes, and those policies may change from time to time. For example, if you hold an interest in a global note through Euroclear or Clearstream, when DTC is the depositary, Euroclear or Clearstream, as applicable, will require those who purchase and sell interests in that note through them to use immediately available funds and comply with other policies and procedures, including deadlines for giving instructions as to transactions that are to be effected on a particular day. There may be more than one financial intermediary in the chain of ownership for an investor. We do not monitor and are not responsible for the policies or actions or records of ownership interests of any of those intermediaries.

Holder s Option to Obtain a Non-Global Note; Special Situations When a Global Note Will Be Terminated

If we issue any series of notes in book-entry form but we choose to give the beneficial owners of that series the right to obtain non-global notes, any beneficial owner entitled to obtain non-global notes may do so by following the applicable procedures of the depositary for that series and that owner s bank, broker or other financial institution through which that owner holds its beneficial interest in the notes. If you are entitled to request a non-global certificate and wish to do so, you will need to allow sufficient lead time to enable us or our agent to prepare the requested certificate.

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In addition, in a few special situations described below, a global note will be terminated and interests in it will be exchanged for certificates in non-global form representing the notes it represented. After that exchange, the choice of whether to hold the notes directly or in street name will be up to the investor. Investors must consult their own banks or brokers to find out how to have their interests in a global note transferred on termination to their own names, so that they will be holders. We have described the rights of holders and street name investors above under Description of the Notes We May Offer Legal Ownership .

Unless otherwise mentioned in the relevant pricing supplement, the special situations for termination of a global note are as follows:

- if the depositary notifies Wachovia that it is unwilling, unable or no longer qualified to continue as depositary for that global note;
- if Wachovia executes and delivers to the relevant trustee an order complying with the requirements of the relevant indenture that this global note shall be so exchangeable; or
- if there has occurred and is continuing a default in the payment of any amount due in respect of the notes or an event of default or an event that, with the giving of notice or lapse of time, or both, would constitute an event of default with respect to these notes.

If a global note is terminated, only the depositary, and not we or the relevant trustee, is responsible for deciding the names of the institutions in whose names the notes represented by the global note will be registered and, therefore, who will be the holders of those notes.

Considerations Relating to Clearstream and Euroclear

Clearstream and Euroclear are securities clearance systems in Europe. Clearstream and Euroclear have informed Wachovia that Clearstream and Euroclear each hold securities for their customers and facilitate the clearance and settlement of securities transactions by electronic book-entry transfer between their respective account holders. Clearstream and Euroclear provide various services including safekeeping, administration, clearance and settlement of internationally traded securities and securities lending and borrowing. Clearstream and Euroclear also deal with domestic securities markets in several countries through established depositary and custodial relationships. Clearstream and Euroclear have established an electronic bridge between their two systems across which their respective participants may settle trades with each other. Clearstream and Euroclear customers are world-wide financial institutions including underwriters, securities brokers and dealers, banks, trust companies and clearing corporations. Indirect access to Clearstream and Euroclear is available to other institutions which clear through or maintain a custodial relationship with an account holder of either system.

Euroclear and Clearstream may be depositaries for a global note. In addition, if DTC is the depositary for a global note, Euroclear and Clearstream may hold interests in the global note as participants in DTC.

As long as any global note is held by Euroclear or Clearstream, as depositary, you may hold an interest in the global note only through an organization that participates, directly or indirectly, in Euroclear or Clearstream. If Euroclear or Clearstream is the depositary for a global note and there is no depositary in the United States, you will not be able to hold interests in that global note through any securities clearance system in the United States.

Payments, deliveries, transfers, exchanges, notices and other matters relating to the notes made through Euroclear or Clearstream must comply with the rules and procedures of those systems. Those systems could change their rules and procedures at any time. We have no control over those systems or their participants and we take no responsibility for their activities. Transactions between participants in Euroclear or Clearstream, on one hand, and participants in DTC, on the other hand, when DTC is the depositary, would also be subject to DTC s rules and procedures.

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Special Timing Considerations for Transactions in Euroclear and Clearstream

Investors will be able to make and receive through Euroclear and Clearstream payments, deliveries, transfers, exchanges, notices and other transactions involving any notes held through those systems only on days when those systems are open for business. Those systems may not be open for business on days when banks, brokers and other institutions are open for business in the United States.

In addition, because of time-zone differences, U.S. investors who hold their interests in the notes through these systems and wish to transfer their interests, or to receive or make a payment or delivery or exercise any other right with respect to their interests, on a particular day may find that the transaction will not be effected until the next business day in Luxembourg or Brussels, as applicable. Thus, investors who wish to exercise rights that expire on a particular day may need to act before the expiration date. In addition, investors who hold their interests through both DTC and Euroclear or Clearstream may need to make special arrangements to finance any purchases or sales of their interest between the U.S. and European clearing systems, and those transactions may settle later than would be the case for transactions within one clearing system.

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UNITED STATES TAXATION

This section describes the material United States federal income tax consequences of owning the notes we are offering. It is the opinion of Sullivan & Cromwell LLP, counsel to Wachovia. It applies to you only if you hold your notes as capital assets for tax purposes. This section does not apply to you if you are a member of a class of holders subject to special rules, such as:

- a dealer in securities or currencies,
- a trader in securities that elects to use a mark-to-market method of accounting for your securities holdings,
- a bank,
- a life insurance company,
- a tax-exempt organization,
- a person that owns notes that are a hedge or that are hedged against interest rate or currency risks,
- a person that owns notes as part of a straddle or conversion transaction for tax purposes, or
- a United States holder (as defined below) whose functional currency for tax purposes is not the U.S. dollar.

This section deals only with notes that are due to mature 30 years or less from the date on which they are issued. The United States federal income tax consequences of owning notes that are due to mature more than 30 years from their date of issue will be discussed in an applicable pricing supplement. This section is based on the Internal Revenue Code of 1986, as amended, its legislative history, existing and proposed regulations under the Internal Revenue Code, published rulings and court decisions, all as currently in effect. These laws are subject to change, possibly on a retroactive basis.

If a partnership holds the notes, the United States federal income tax treatment of a partner will generally depend on the status of the partner and the tax treatment of the partnership. A partner in a partnership holding the notes should consult its tax advisor with regard to the United States federal income tax treatment of an investment in the notes.

Please consult your own tax advisor concerning the consequences of owning these notes in your particular circumstances under the Code and the laws of any other taxing jurisdiction.

United States Holders

This subsection describes the tax consequences to a United States holder. You are a United States holder if you are a beneficial owner of a note and you are:

- a citizen or resident of the United States,
- a domestic corporation,
- an estate whose income is subject to United States federal income tax regardless of its source, or
- a trust if a United States court can exercise primary supervision over the trust s administration and one or more United States persons are authorized to control all substantial decisions of the trust.

If you are not a United States holder, this subsection does not apply to you and you should refer to United States Alien Holders below.

Payments of Interest

Except as described below in the case of interest on a discount note that is not qualified stated interest each as defined below under Original Issue Discount General , you will be taxed on any interest on your note, whether payable in U.S. dollars or a foreign currency, including a composite currency or basket of currencies other than U.S. dollars, as ordinary income at the time you receive the interest or when it accrues, depending on your method of accounting for tax purposes.

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Cash Basis Taxpayers. If you are a taxpayer that uses the cash receipts and disbursements method of accounting for tax purposes and you receive an interest payment that is denominated in, or determined by reference to, a foreign currency, you must recognize income equal to the U.S. dollar value of the interest payment, based on the exchange rate in effect on the date of receipt, regardless of whether you actually convert the payment into U.S. dollars.

Accrual Basis Taxpayers. If you are a taxpayer that uses an accrual method of accounting for tax purposes, you may determine the amount of income that you recognize with respect to an interest payment denominated in, or determined by reference to, a foreign currency by using one of two methods. Under the first method, you will determine the amount of income accrued based on the average exchange rate in effect during the interest accrual period or, with respect to an accrual period that spans two taxable years, that part of the period within the taxable year.

If you elect the second method, you would determine the amount of income accrued on the basis of the exchange rate in effect on the last day of the accrual period, or, in the case of an accrual period that spans two taxable years, the exchange rate in effect on the last day of the part of the period within the taxable year. Additionally, under this second method, if you receive a payment of interest within five business days of the last day of your accrual period or taxable year, you may instead translate the interest accrued into U.S. dollars at the exchange rate in effect on the day that you actually receive the interest payment. If you elect the second method it will apply to all debt instruments that you hold at the beginning of the first taxable year to which the election applies and to all debt instruments that you subsequently acquire. You may not revoke this election without the consent of the Internal Revenue Service.

When you actually receive an interest payment, including a payment attributable to accrued but unpaid interest upon the sale or retirement of your note, denominated in, or determined by reference to, a foreign currency for which you accrued an amount of income, you will recognize ordinary income or loss measured by the difference, if any, between the exchange rate that you used to accrue interest income and the exchange rate in effect on the date of receipt, regardless of whether you actually convert the payment into U.S. dollars.

Original Issue Discount

General. If you own a note, other than a short-term note with a term of one year or less, it will be treated as a discount note issued at an original issue discount if the amount by which the note s stated redemption price at maturity exceeds its issue price is more than a *de minimis* amount. Generally, a note s issue price will be the first price at which a substantial amount of notes included in the issue of which the note is a part is sold to persons other than bond houses, brokers, or similar persons or organizations acting in the capacity of underwriters, placement agents, or wholesalers. A note s stated redemption price at maturity is the total of all payments provided by the note that are not payments of qualified stated interest. Generally, an interest payment on a note is qualified stated interest if it is one of a series of stated interest payments on a note that are unconditionally payable at least annually at a single fixed rate, with certain exceptions for lower rates paid during some periods, applied to the outstanding principal amount of the note. There are special rules for variable rate notes that are discussed under Variable Rate Notes .

In general, your note is not a discount note if the amount by which its stated redemption price at maturity exceeds its issue price is less than the de minimis amount of $^{1}/4$ of 1 percent of its stated redemption price at maturity multiplied by the number of complete years to its maturity. Your note will have de minimis original issue discount if the amount of the excess is less than the de minimis amount. If your note has de minimis original issue discount, you must include the de minimis amount in income as stated principal payments are made on the note, unless you make the election described below under Election to Treat All Interest as Original Issue Discount . You can determine the includible amount with respect to each such payment by multiplying the total amount of your note s de minimis original issue discount by a fraction equal to:

the amount of the principal payment made

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divided by:

the stated principal amount of the note.

Generally, if your discount note matures more than one year from its date of issue, you must include original issue discount, or OID, in income before you receive cash attributable to that income. The amount of OID that you must include in income is calculated using a constant-yield method, and generally you will include increasingly greater amounts of OID in income over the life of your note. More specifically, you can calculate the amount of OID that you must include in income by adding the daily portions of OID with respect to your discount note for each day during the taxable year or portion of the taxable year that you hold your discount note. You can determine the daily portion by allocating to each day in any accrual period a pro rata portion of the OID allocable to that accrual period. You may select an accrual period of any length with respect to your discount note and you may vary the length of each accrual period over the term of your discount note. However, no accrual period may be longer than one year and each scheduled payment of interest or principal on the discount note must occur on either the first or final day of an accrual period.

You can determine the amount of OID allocable to an accrual period by:

multiplying your discount note s adjusted issue price at the beginning of the accrual period by your note s yield to maturity, and then

subtracting from this figure the sum of the payments of qualified stated interest on your note allocable to the accrual period.

You must determine the discount note s yield to maturity on the basis of compounding at the close of each accrual period and adjusting for the length of each accrual period. Further, you determine your discount note s adjusted issue price at the beginning of any accrual period by:

adding your discount note s issue price and any accrued OID for each prior accrual period, and then

subtracting any payments previously made on your discount note that were not qualified stated interest payments.

If an interval between payments of qualified stated interest on your discount note contains more than one accrual period, then, when you determine the amount of OID allocable to an accrual period, you must allocate the amount of qualified stated interest payable at the end of the interval, including any qualified stated interest that is payable on the first day of the accrual period immediately following the interval, pro rata to each accrual period in the interval based on their relative lengths. In addition, you must increase the adjusted issue price at the beginning of each accrual period in the interval by the amount of any qualified stated interest that has accrued prior to the first day of the accrual period but that is not payable until the end of the interval. You may compute the amount of OID allocable to an initial short accrual period by using any reasonable method if all other accrual periods, other than a final short accrual period, are of equal length.

The amount of OID allocable to the final accrual period is equal to the difference between:

the amount payable at the maturity of your note, other than any payment of qualified stated interest, and your note s adjusted issue price as of the beginning of the final accrual period.

Acquisition Premium. If you purchase your note for an amount that is less than or equal to the sum of all amounts, other than qualified stated interest, payable on your note after the purchase date but is greater than the amount of your note s adjusted issue price, as determined above under General , the excess is

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acquisition premium. If you do not make the election described below under Election to Treat All Interest as Original Issue Discount , then you must reduce the daily portions of OID by a fraction equal to:

the excess of your adjusted basis in the note immediately after purchase over the adjusted issue price of the note

divided by:

the excess of the sum of all amounts payable, other than qualified stated interest, on the note after the purchase date over the note s adjusted issue price.

Pre-Issuance Accrued Interest. An election may be made to decrease the issue price of your note by the amount of pre-issuance accrued interest if:

a portion of the initial purchase price of your note is attributable to pre-issuance accrued interest,

the first stated interest payment on your note is to be made within one year of your note s issue date, and

the payment will equal or exceed the amount of pre-issuance accrued interest.

If this election is made, a portion of the first stated interest payment will be treated as a return of the excluded pre-issuance accrued interest and not as an amount payable on your note.

Notes Subject to Contingencies Including Optional Redemption. Your note is subject to a contingency if it provides for an alternative payment schedule or schedules applicable upon the occurrence of a contingency or contingencies, other than a remote or incidental contingency, whether such contingency relates to payments of interest or of principal. In such a case, you must determine the yield and maturity of your note by assuming that the payments will be made according to the payment schedule most likely to occur if:

the timing and amounts of the payments that comprise each payment schedule are known as of the issue date and

one of such schedules is significantly more likely than not to occur.

If there is no single payment schedule that is significantly more likely than not to occur, other than because of a mandatory sinking fund, you must include income on your note in accordance with the general rules that govern contingent payment obligations. These rules will be discussed in the applicable pricing supplement.

Notwithstanding the general rules for determining yield and maturity, if your note is subject to contingencies, and either you or we have an unconditional option or options that, if exercised, would require payments to be made on the note under an alternative payment schedule or schedules, then:

- in the case of an option or options that we may exercise, we will be deemed to exercise or not exercise an option or combination of options in the manner that minimizes the yield on your note and

- in the case of an option or options that you may exercise, you will be deemed to exercise or not exercise an option or combination of options in the manner that maximizes the yield on your note.

If both you and we hold options described in the preceding sentence, those rules will apply to each option in the order in which they may be exercised. You may determine the yield on your note for the purposes of those calculations by using any date on which your note may be redeemed or repurchased as the maturity date and the amount payable on the date that you chose in accordance with the terms of your note as the principal amount payable at maturity.

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If a contingency, including the exercise of an option, actually occurs or does not occur contrary to an assumption made according to the above rules then, except to the extent that a portion of your note is repaid as a result of this change in circumstances and solely to determine the amount and accrual of OID, you must redetermine the yield and maturity of your note by treating your note as having been retired and reissued on the date of the change in circumstances for an amount equal to your note s adjusted issue price on that date.

Election to Treat All Interest as Original Issue Discount. You may elect to include in gross income all interest that accrues on your note using the constant-yield method described above under General , with the modifications described below. For purposes of this election, interest will include stated interest, OID, de minimis original issue discount, market discount, de minimis market discount and unstated interest, as adjusted by any amortizable bond premium, described below under Notes Purchased at a Premium, or acquisition premium.

If you make this election for your note, then, when you apply the constant-yield method:

- the issue price of your note will equal your cost,
- the issue date of your note will be the date you acquired it, and
- no payments on your note will be treated as payments of qualified stated interest.

Generally, this election will apply only to the note for which you make it; however, if the note has amortizable bond premium, you will be deemed to have made an election to apply amortizable bond premium against interest for all debt instruments with amortizable bond premium, other than debt instruments the interest on which is excludible from gross income, that you hold as of the beginning of the taxable year to which the election applies or any taxable year thereafter. Additionally, if you make this election for a market discount note, you will be treated as having made the election discussed below under Notes Purchased with Market Discount to include market discount in income currently over the life of all debt instruments that you currently own or later acquire. You may not revoke any election to apply the constant-yield method to all interest on a note or the deemed elections with respect to amortizable bond premium or market discount notes without the consent of the Internal Revenue Service.

Variable Rate Notes. Your note will be a variable rate note if:

- your note s issue price does not exceed the total noncontingent principal payments by more than the lesser of:

  1. .015 multiplied by the product of the total noncontingent principal payments and the number of complete years to maturity from the issue date, or
  2. 15 percent of the total noncontingent principal payments; and

- your note provides for stated interest, compounded or paid at least annually, only at:

  1. one or more qualified floating rates,

2. a single fixed rate and one or more qualified floating rates,

3. a single objective rate, or

4. a single fixed rate and a single objective rate that is a qualified inverse floating rate.

Your note will have a variable rate that is a qualified floating rate if:

- variations in the value of the rate can reasonably be expected to measure contemporaneous variations in the cost of newly borrowed funds in the currency in which your note is denominated; or

- the rate is equal to such a rate multiplied by either:

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1. a fixed multiple that is greater than 0.65 but not more than 1.35, or

2. a fixed multiple greater than 0.65 but not more than 1.35, increased or decreased by a fixed rate; and

the value of the rate on any date during the term of your note is set no earlier than three months prior to the first day on which that value is in effect and no later than one year following that first day.

If your note provides for two or more qualified floating rates that are within 0.25 percentage points of each other on the issue date or can reasonably be expected to have approximately the same values throughout the term of the note, the qualified floating rates together constitute a single qualified floating rate.

Your note will not have a qualified floating rate, however, if the rate is subject to certain restrictions (including caps, floors, governors, or other similar restrictions) unless such restrictions are fixed throughout the term of the note or are not reasonably expected to significantly affect the yield on the note.

Your note will have a variable rate that is a single objective rate if:

the rate is not a qualified floating rate,

the rate is determined using a single, fixed formula that is based on objective financial or economic information that is not within the control of or unique to the circumstances of the issuer or a related party, and

the value of the rate on any date during the term of your note is set no earlier than three months prior to the first day on which that value is in effect and no later than one year following that first day.

Your note will not have a variable rate that is an objective rate, however, if it is reasonably expected that the average value of the rate during the first half of your note s term will be either significantly less than or significantly greater than the average value of the rate during the final half of your note s term.

An objective rate as described above is a qualified inverse floating rate if:

the rate is equal to a fixed rate minus a qualified floating rate, and

the variations in the rate can reasonably be expected to inversely reflect contemporaneous variations in the cost of newly borrowed funds.

Your note will also have a single qualified floating rate or an objective rate if interest on your note is stated at a fixed rate for an initial period of one year or less followed by either a qualified floating rate or an objective rate for a subsequent period, and either:

- the fixed rate and the qualified floating rate or objective rate have values on the issue date of the note that do not differ by more than 0.25 percentage points, or

- the value of the qualified floating rate or objective rate is intended to approximate the fixed rate.

Commercial paper rate notes, prime rate notes, LIBOR notes, EURIBOR rate notes, treasury rate notes, CMT rate notes, CD rate notes, CPI rate notes, and federal funds rate notes generally will be treated as variable rate notes under these rules.

In general, if your variable rate note provides for stated interest at a single qualified floating rate or objective rate, or one of those rates after a single fixed rate for an initial period, all stated interest on your note is qualified stated interest. In this case, the amount of OID, if any, is determined by using, in the case of a qualified floating rate or qualified inverse floating rate, the value as of the issue date of the qualified floating

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rate or qualified inverse floating rate, or, for any other objective rate, a fixed rate that reflects the yield reasonably expected for your note.

If your variable rate note does not provide for stated interest at a single qualified floating rate or a single objective rate, and also does not provide for interest payable at a fixed rate other than a single fixed rate for an initial period, you generally must determine the interest and OID accruals on your note by:

- determining a fixed rate substitute for each variable rate provided under your variable rate note,
- constructing the equivalent fixed rate debt instrument, using the fixed rate substitute described above,
- determining the amount of qualified stated interest and OID with respect to the equivalent fixed rate debt instrument, and
- adjusting for actual variable rates during the applicable accrual period.

When you determine the fixed rate substitute for each variable rate provided under the variable rate note, you generally will use the value of each variable rate as of the issue date or, for an objective rate that is not a qualified inverse floating rate, a rate that reflects the reasonably expected yield on your note.

If your variable rate note provides for stated interest either at one or more qualified floating rates or at a qualified inverse floating rate, and also provides for stated interest at a single fixed rate other than at a single fixed rate for an initial period, you generally must determine interest and OID accruals by using the method described in the previous paragraph. However, your variable rate note will be treated, for purposes of the first three steps of the determination, as if your note had provided for a qualified floating rate, or a qualified inverse floating rate, rather than the fixed rate. The qualified floating rate, or qualified inverse floating rate, that replaces the fixed rate must be such that the fair market value of your variable rate note as of the issue date approximates the fair market value of an otherwise identical debt instrument that provides for the qualified floating rate, or qualified inverse floating rate, rather than the fixed rate.

Short-Term Notes. In general, if you are an individual or other cash basis United States holder of a short-term note, you are not required to accrue OID, as specially defined below for the purposes of this paragraph, for United States federal income tax purposes unless you elect to do so (although it is possible that you may be required to include any stated interest in income as you receive it). If you are an accrual basis taxpayer, a taxpayer in a special class, including, but not limited to, a regulated investment company, common trust fund, or a certain type of pass-through entity, or a cash basis taxpayer who so elects, you will be required to accrue OID on short-term notes on either a straight-line basis or under the constant-yield method, based on daily compounding. If you are not required and do not elect to include OID in income currently, any gain you realize on the sale or retirement of your short-term note will be ordinary income to the extent of the accrued OID, which will be determined on a straight-line basis unless you make an election to accrue the OID under the constant-yield method, through the date of sale or retirement. However, if you are not required and do not elect to accrue OID on your short-term notes, you will be required to defer deductions for interest on borrowings allocable to your short-term notes in an amount not exceeding the deferred income until the deferred income is realized.

When you determine the amount of OID subject to these rules, you must include all interest payments on your short-term note, including stated interest, in your short-term note s stated redemption price at maturity.

Foreign Currency Discount Notes. If your discount note is denominated in, or determined by reference to, a foreign currency, you must determine OID for any accrual period on your discount note in the foreign currency and then translate the amount of OID into U.S. dollars in the same manner as stated interest accrued by an accrual basis United States holder, as described under United States Holders Payments of

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Interest . You may recognize ordinary income or loss when you receive an amount attributable to OID in connection with a payment of interest or the sale or retirement of your note.

Notes Purchased at a Premium

If you purchase your note for an amount in excess of its principal amount, you may elect to treat the excess as amortizable bond premium. If you make this election, you will reduce the amount required to be included in your income each year with respect to interest on your note by the amount of amortizable bond premium allocable to that year, based on your note s yield to maturity. If your note is denominated in, or determined by reference to, a foreign currency, you will compute your amortizable bond premium in units of the foreign currency and your amortizable bond premium will reduce your interest income in units of the foreign currency. Gain or loss recognized that is attributable to changes in exchange rates between the time your amortized bond premium offsets interest income and the time of the acquisition of your note is generally taxable as ordinary income or loss. If you make an election to amortize bond premium, it will apply to all debt instruments, other than debt instruments the interest on which is excludible from gross income, that you hold at the beginning of the first taxable year to which the election applies or that you thereafter acquire, and you may not revoke it without the consent of the Internal Revenue Service. See also Original Issue Discount Election to Treat All Interest as Original Issue Discount .

Notes Purchased with Market Discount

You will be treated as if you purchased your note, other than a short-term note, at a market discount, and your note will be a market discount note if:

- in the case of an initial purchaser, you purchase your note for less than its issue price as determined above under Original Issue Discount General , and
- the difference between the note s stated redemption price at maturity or, in the case of a discount note, the note s revised issue price, and the price you paid for your note is equal to or greater than $^{1}/4$ of 1 percent of your note s stated redemption price at maturity or revised issue price, respectively, multiplied by the number of complete years to the note s maturity.

To determine the revised issue price of your note for these purposes, you generally add any OID that has accrued on your note to its issue price.

If your note s stated redemption price at maturity or, in the case of a discount note, its revised issue price, exceeds the price you paid for the note by less than $^{1}/4$ of 1 percent multiplied by the number of complete years to the note s maturity, the excess constitutes de minimis market discount, and the rules discussed below are not applicable to you.

You must treat any gain you recognize on the maturity or disposition of your market discount note as ordinary income to the extent of the accrued market discount on your note. Alternatively, you may elect to include market discount in income currently over the life of your note. If you make this election, it will apply to all debt instruments with market discount that you acquire on or after the first day of the first taxable year to which the election applies. You may not revoke this election without the consent of the Internal Revenue Service. If you own a market discount note and do not make this election, you will generally be required to defer deductions for interest on borrowings allocable to your note in an amount not exceeding the accrued market discount on your note until the maturity or disposition of your note.

You will accrue market discount on your market discount note on a straight-line basis unless you elect to accrue market discount using a constant-yield method. If you make this election, it will apply only to the note with respect to which it is made and you may not revoke it.

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Purchase, Sale and Retirement of the Notes

Your tax basis in your note will generally be the U.S. dollar cost, as defined below, of your note, adjusted by:

- adding any OID or market discount, de minimis original issue discount and de minimis market discount previously included in income with respect to your note, and then
- subtracting any payments on your note that are not qualified stated interest payments and any amortizable bond premium applied to reduce interest on your note.

If you purchase your note with foreign currency, the U.S. dollar cost of your note will generally be the U.S. dollar value of the purchase price on the date of purchase. However, if you are a cash basis taxpayer, or an accrual basis taxpayer if you so elect, and your note is traded on an established securities market, as defined in the applicable Treasury regulations, the U.S. dollar cost of your note will be the U.S. dollar value of the purchase price on the settlement date of your purchase.

You will generally recognize gain or loss on the sale or retirement of your note equal to the difference between the amount you realize on the sale or retirement and your tax basis in your note. If your note is sold or retired for an amount in foreign currency, the amount you realize will be the U.S. dollar value of such amount on the date the note is disposed of or retired, except that in the case of a note that is traded on an established securities market, as defined in the applicable Treasury regulations, a cash basis taxpayer, or an accrual basis taxpayer that so elects, will determine the amount realized based on the U.S. dollar value of the foreign currency on the settlement date of the sale.

You will recognize capital gain or loss when you sell or retire your note, except to the extent:

- described above under Original Issue Discount Short-Term Notes or Notes Purchased with Market Discount ,
- attributable to accrued but unpaid interest,
- the rules governing contingent payment obligations apply, or
- attributable to changes in exchange rates as described below.

Capital gain of a noncorporate United States holder that is recognized before January 1, 2009 is generally taxed at a maximum rate of 15% where the holder has a holding period greater than one year.

You must treat any portion of the gain or loss that you recognize on the sale or retirement of a note as ordinary income or loss to the extent attributable to changes in exchange rates. However, you take exchange gain or loss into account only to the extent of the total gain or loss you realize on the transaction.

Exchange of Amounts in Other Than U.S. Dollars

If you receive foreign currency as interest on your note or on the sale or retirement of your note, your tax basis in the foreign currency will equal its U.S. dollar value when the interest is received or at the time of the sale or retirement. If you purchase foreign currency, you generally will have a tax basis equal to the U.S. dollar value of the foreign currency on the date of your purchase. If you sell or dispose of a foreign currency, including if you use it to purchase notes or exchange it for U.S. dollars, any gain or loss recognized generally will be ordinary income or loss.

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Indexed Notes, Exchangeable Notes, and Contingent Payment Notes

The applicable pricing supplement will discuss any special United States federal income tax rules with respect to notes the payments on which are determined by reference to any index, notes that are exchangeable at our option or the option of the holder into securities of an issuer other than Wachovia or into other property, and other notes that are subject to the rules governing contingent payment obligations which are not subject to the rules governing variable rate notes.

United States Alien Holders

This subsection describes the tax consequences to a United States alien holder. You are a United States alien holder if you are the beneficial owner of a note and are, for United States federal income tax purposes:

- a nonresident alien individual,
- a foreign corporation, or
- an estate or trust that in either case is not subject to United States federal income tax on a net income basis on income or gain from a note.

If you are a United States holder, this subsection does not apply to you.

This discussion assumes that the note is not subject to the rules of Section 871(h)(4)(A) of the Internal Revenue Code, relating to interest payments that are determined by reference to the income, profits, changes in the value of property or other attributes of the debtor or a related party.

Under United States federal income and estate tax law, and subject to the discussion of backup withholding below, if you are a United States alien holder of a note:

- we and other U.S. payors generally will not be required to deduct United States withholding tax from payments of principal, premium, if any, and interest, including OID, to you if, in the case of payments of interest:

  1. you do not actually or constructively own 10% or more of the total combined voting power of all classes of stock of the Company entitled to vote,
  2. you are not a controlled foreign corporation that is related to the Company through stock ownership, and

3. the U.S. payor does not have actual knowledge or reason to know that you are a United States person and:

   a. you have furnished to the U.S. payor an Internal Revenue Service Form W-8BEN or an acceptable substitute form upon which you certify, under penalties of perjury, that you are (or, in the case of a United States alien holder that is a partnership or an estate or trust, such forms certifying that each partner in the partnership or beneficiary of the estate or trust is) a non-United States person,

   b. in the case of payments made outside the United States to you at an offshore account (generally, an account maintained by you at a bank or other financial institution at any location outside the United States), you have furnished to the U.S. payor documentation that establishes your identity and your status as a non-United States person,

   c. the U.S. payor has received a withholding certificate (furnished on an appropriate Internal Revenue Service Form W-8 or an acceptable substitute form) from a person claiming to be:

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i. a withholding foreign partnership (generally a foreign partnership that has entered into an agreement with the Internal Revenue Service to assume primary withholding responsibility with respect to distributions and guaranteed payments it makes to its partners),

ii. a qualified intermediary (generally a non-United States financial institution or clearing organization or a non-United States branch or office of a United States financial institution or clearing organization that is a party to a withholding agreement with the Internal Revenue Service), or

iii. a U.S. branch of a non-United States bank or of a non-United States insurance company,

and the withholding foreign partnership, qualified intermediary or U.S. branch has received documentation upon which it may rely to treat the payment as made to a non-United States person that is, for United States federal income tax purposes, the beneficial owner of the payment on the notes in accordance with U.S. Treasury regulations (or, in the case of a qualified intermediary, in accordance with its agreement with the Internal Revenue Service),

d. the U.S. payor receives a statement from a securities clearing organization, bank or other financial institution that holds customers securities in the ordinary course of its trade or business,

i. certifying to the U.S. payor under penalties of perjury that an Internal Revenue Service Form W-8BEN or an acceptable substitute form has been received from you by it or by a similar financial institution between it and you, and

ii. to which is attached a copy of the Internal Revenue Service Form W-8BEN or acceptable substitute form, or

e. the U.S. payor otherwise possesses documentation upon which it may rely to treat the payment as made to a non-United States person that is, for United States federal income tax purposes, the beneficial owner of the payment on the notes in accordance with U.S. Treasury regulations; and

no deduction for any United States federal withholding tax will be made from any gain that you realize on the sale or exchange of your note.

Further, a note held by an individual who at death is not a citizen or resident of the United States will not be includible in the individual s gross estate for United States federal estate tax purposes if:

the decedent did not actually or constructively own 10% or more of the total combined voting power of all classes of stock of the Company entitled to vote at the time of death and

the income on the note would not have been effectively connected with a United States trade or business of the decedent at the same time.

Treasury Regulations Requiring Disclosure of Reportable Transactions

Recently-promulgated Treasury regulations require United States taxpayers to report certain transactions that give rise to a loss in excess of certain thresholds (a Reportable Transaction). Under these regulations, if the notes are denominated in a foreign currency, a United States holder (or a United States alien holder that holds the notes in connection with a U.S. trade or business) that recognizes a loss with respect to the notes that is characterized as an ordinary loss due to changes in currency exchange rates (under any of the rules discussed above) would be required to report the loss on Internal Revenue Service Form 8886

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(Reportable Transaction Statement) if the loss exceeds the thresholds set forth in the regulations. For individuals and trusts, this loss threshold is $50,000 in any single taxable year. For other types of taxpayers and other types of losses, the thresholds are higher. You should consult with your tax advisor regarding any tax filing and reporting obligations that may apply in connection with acquiring, owning and disposing of notes.

Backup Withholding And Information Reporting

In general, if you are a noncorporate United States holder, we and other payors are required to report to the Internal Revenue Service all payments of principal, any premium and interest on your note, and the accrual of OID on a discount note. In addition, we and other payors are required to report to the Internal Revenue Service any payment of proceeds of the sale of your note before maturity within the United States. Additionally, backup withholding will apply to any payments, including payments of OID, if you fail to provide an accurate taxpayer identification number, or you are notified by the Internal Revenue Service that you have failed to report all interest and dividends required to be shown on your federal income tax returns.

In general, if you are a United States alien holder, payments of principal, premium or interest, including OID, made by us and other payors to you will not be subject to backup withholding and information reporting, provided that the certification requirements described above under United States Alien Holders are satisfied or you otherwise establish an exemption. However, we and other payors are required to report payments of interest on your notes on Internal Revenue Service Form 1042-S even if the payments are not otherwise subject to information reporting requirements. In addition, payment of the proceeds from the sale of notes effected at a United States office of a broker will not be subject to backup withholding and information reporting provided that:

- the broker does not have actual knowledge or reason to know that you are a United States person and you have furnished to the broker:
  - an appropriate Internal Revenue Service Form W-8 or an acceptable substitute form upon which you certify, under penalties of perjury, that you are not a United States person, or
  - other documentation upon which it may rely to treat the payment as made to a non-United States person in accordance with U.S. Treasury regulations, or
- you otherwise establish an exemption.

If you fail to establish an exemption and the broker does not possess adequate documentation of your status as a non-United States person, the payments may be subject to information reporting and backup withholding. However, backup withholding will not apply with respect to payments made to an offshore account maintained by you unless the broker has actual knowledge that you are a United States person.

In general, payment of the proceeds from the sale of notes effected at a foreign office of a broker will not be subject to information reporting or backup withholding. However, a sale effected at a foreign office of a broker will be subject to information reporting and backup withholding if:

- the proceeds are transferred to an account maintained by you in the United States, the payment of proceeds or the confirmation of the sale is mailed to you at a United States address, or

the sale has some other specified connection with the United States as provided in U.S. Treasury regulations,

unless the broker does not have actual knowledge or reason to know that you are a United States person and the documentation requirements described above (relating to a sale of notes effected at a United States office of a broker) are met or you otherwise establish an exemption.

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In addition, payment of the proceeds from the sale of notes effected at a foreign office of a broker will be subject to information reporting if the broker is:

- a United States person,
- a controlled foreign corporation for United States tax purposes,
- a foreign person 50% or more of whose gross income is effectively connected with the conduct of a United States trade or business for a specified three-year period, or
- a foreign partnership, if at any time during its tax year:
  - one or more of its partners are U.S. persons , as defined in U.S. Treasury regulations, who in the aggregate hold more than 50% of the income or capital interest in the partnership, or
  - such foreign partnership is engaged in the conduct of a United States trade or business,

unless the broker does not have actual knowledge or reason to know that you are a United States person and the documentation requirements described above (relating to a sale of notes effected at a United States office of a broker) are met or you otherwise establish an exemption. Backup withholding will apply if the sale is subject to information reporting and the broker has actual knowledge that you are a United States person.

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EUROPEAN UNION DIRECTIVE ON TAXATION OF SAVINGS INCOME

On June 3, 2003, the Council of the European Union (Ecofin) approved a directive regarding the taxation of, and information exchange among member states of the European Union (EU Member States) with respect to, interest income. Accordingly, each EU Member State is required to implement provisions that will require paying agents (within the meaning of the directive) established within its territory to provide to the competent authority of this state information about the payment of interest made to any individual resident in another EU Member State as the beneficial owner of the interest. The competent authority of the EU Member State of the paying agent (within the meaning of the directive) is then required to communicate this information to the competent authority of the EU Member State of which the beneficial owner of the interest is a resident.

For a transitional period, however, and until a number of conditions are met, Austria, Belgium and Luxembourg may opt instead to withhold tax from interest payments within the meaning of the directive at a rate of 15% for the first three years from application of the provisions of the directive, of 20% for the subsequent three years, and of 35% from the seventh year after application of the provisions of the directive. Austria, Belgium and Luxembourg shall, however, provide for one or both of the procedures set forth in article 13 of the directive order to ensure that the beneficial owners may request that no tax be withheld.

The Council of the European Union agreed that the provisions to be enacted by the EU Member States for implementation of the directive shall be applied by the EU Member States as from July 1, 2005 provided that (i) Switzerland, Liechtenstein, San Marino, Monaco and Andorra apply from that same date measures equivalent to those contained in the directive, in accordance with agreements entered into by them with the European Community and (ii) also all the relevant dependent or associated territories (the Channel Islands, the Isle of Man and the dependent or associated territories in the Caribbean) apply from that same date an automatic exchange of information or, during the transitional period described above, apply a withholding tax in the described manner.

EMPLOYEE RETIREMENT INCOME SECURITY ACT

A fiduciary of a pension, profit-sharing or other employee benefit plan subject to the Employment Retirement Income Security Act of 1974, as amended (ERISA), should consider the fiduciary standards of ERISA in the context of the plan's particular circumstances before authorizing an investment in the notes. Among other factors, the fiduciary should consider whether the investment would satisfy the prudence and diversification requirements of ERISA and would be consistent with the documents and instruments governing the plan.

Section 406 of ERISA and Section 4975 of the Internal Revenue Code prohibit an employee benefit plan, as well as individual retirement accounts and Keogh plans subject to Section 4975 of the Internal Revenue Code, from engaging in certain transactions involving plan assets with persons who are parties in interest under ERISA or disqualified persons under the Internal Revenue Code with respect to the plan. A violation of these prohibited transaction rules may result in excise tax or other liabilities under ERISA and Section 4975 of the Internal Revenue Code for such persons, unless exemptive relief is available under an applicable statutory or administrative exemption. Therefore, a fiduciary of an employee benefit plan should also consider whether an investment in the notes might constitute or give rise to a prohibited transaction under ERISA and the Internal Revenue Code. Employee benefit plans which are governmental plans (as defined in Section 3(32) of ERISA), certain church plans (as defined in Section 3(33) of ERISA), and foreign plans (as described in Section 4(b)(4) of ERISA) generally are not subject to the requirements of ERISA or Section 4975 of the Internal Revenue Code.

Wachovia and certain of its affiliates may each be considered a party in interest or disqualified person with respect to many employee benefit plans. This could be the case, for example, if one of these companies is a service provider to a plan. Special caution should be exercised, therefore, before notes are purchased by an employee benefit plan. In particular, the fiduciary of the plan should consider whether exemptive relief is available under an applicable administrative exemption. The Department of Labor has issued five prohibited

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transaction class exemptions that could apply to exempt the purchase, sale and holding of notes from the prohibited transaction provisions of ERISA and the Internal Revenue Code. Those class exemptions are Prohibited Transaction Exemption 96-23 (for transactions determined by in-house asset managers), Prohibited Transaction Exemption 95-60 (for certain transactions involving insurance company general accounts), Prohibited Transaction Exemption 91-38 (for certain transactions involving bank investment funds), Prohibited Transaction Exemption 90-1 (for certain transactions involving insurance company separate accounts), and Prohibited Transaction Exemption 84-14 (for certain transactions determined by independent qualified asset managers).

Due to the complexity of these rules and the penalties that may be imposed upon persons involved in non-exempt prohibited transactions, it is particularly important that fiduciaries or other persons considering the purchase of notes on behalf of or with plan assets of any employee benefit plan consult with their counsel regarding the consequences under ERISA and the Internal Revenue Code of the acquisition of the notes and the availability of exemptive relief under Prohibited Transaction Exemption 96-23, 95-60, 91-38, 90-1 or 84-14.

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PLAN OF DISTRIBUTION

Unless otherwise indicated in any pricing supplement, the U.S. distribution agents shall be Wachovia Capital Markets, LLC, an indirect, wholly-owned subsidiary of Wachovia; ABN AMRO Incorporated; Barclays Capital Inc.; Bear, Stearns & Co. Inc.; Blaylock & Partners, L.P.; Citigroup Global Markets Inc.; Credit Suisse First Boston LLC; Goldman, Sachs & Co.; Greenwich Capital Markets, Inc.; Guzman & Company; J.P. Morgan Securities Inc.; Keefe, Bruyette & Woods, Inc.; Lehman Brothers Inc.; Loop Capital Markets, LLC; Merrill Lynch, Pierce, Fenner & Smith Inc.; Samuel A. Ramirez & Co. Inc.; Sandler O Neill & Partners, L.P.; UBS Securities LLC; Utendahl Capital Partners, L.P.; The Williams Capital Group, L.P.; and the European distribution agents shall be Wachovia Securities International Limited, an indirect, wholly-owned subsidiary of Wachovia; Barclays Bank PLC; Bear, Stearns International Limited; Citigroup Global Markets Limited; Credit Suisse First Boston (Europe) Limited; Goldman Sachs International; Guzman & Company; J.P. Morgan Securities Ltd.; Lehman Brothers International (Europe); Merrill Lynch International; UBS AG, acting through its business group UBS Securities and Utendahl Capital Partners, L.P. Under the terms of a Distribution Agreement among Wachovia and these agents, Wachovia may sell notes to an agent, acting as principal, for resale to one or more investors or other purchasers at varying prices related to prevailing market prices at the time of resale, as determined by any of these agents or, if so agreed, at a fixed offering price. A form of Distribution Agreement has been filed as an exhibit to the registration statement for this prospectus. Unless otherwise indicated in the relevant pricing supplement, any note sold to an agent as principal will be purchased by that agent at a price equal to 100% of the principal amount of that note, less a percentage not exceeding the maximum commission applicable to any agency sale of a note of identical maturity, and, subject to the restriction noted in the following sentence, may be resold by that Agent to investors and other purchasers. An agent may offer the notes it has purchased as principal to other brokers or dealers at a discount and, unless otherwise indicated in any pricing supplement, the discount allowed to any broker or dealer will not exceed the discount to be received by that agent from Wachovia. After the initial public offering of notes, the public offering price (in the case of notes to be resold on a fixed public offering price basis), the concession and the discount may be changed.

Wachovia may also offer the notes on a continuing basis through the agents, which have agreed to use their reasonable efforts to solicit offers to purchase the notes, on an agency basis. When Wachovia has sold notes through an agent on an agency basis, it will pay that agent a commission (or grant a discount) as agreed by Wachovia and that agent of from 0.125% to 8% of the principal amount of each note sold through that agent. Any agent will have the right, in its discretion reasonably exercised, without notice to Wachovia, to reject any offer to purchase notes received by it in whole or in part.

Unless otherwise mentioned in the relevant pricing supplement, the obligations of any agents to purchase the notes will be subject to certain conditions precedent, and each of the agents with respect to a sale of notes will be obligated to purchase all of its notes if any are purchased.

Wachovia has reserved the right to sell notes directly to investors on its own behalf in those jurisdictions where it is authorized to do so. No selling commission will be payable nor will a selling discount be allowed on any sales made directly by Wachovia.

Wachovia has reserved the right to withdraw, cancel or modify the offer made by this prospectus without notice and may reject orders in whole or in part whether placed directly with Wachovia or with an agent. No termination date has been established for the offering of the notes.

The notes are a new issue of securities with no established trading market. Wachovia has been advised by the agents that they intend to make a market in the notes but are not obligated to do so and may discontinue market-making at any time without notice. The agents may from time to time purchase and sell notes in the secondary market, but no agent is obligated to do so. We can give no assurance that the notes offered by this prospectus will be sold or that there will be a secondary market for the notes (or liquidity in such secondary market, if one develops).

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We have applied to list on the Luxembourg Stock Exchange any notes issued under this prospectus during the twelve-month period after the date of this prospectus. We may also list any notes on any additional securities exchanges on which we and the agents agree in relation to each issuance. We may also issue unlisted notes.

Unless otherwise indicated in any pricing supplement, payment of the purchase price of notes, other than notes denominated in a non-U.S. dollar currency, will be required to be made in funds immediately available in The City of New York. The notes will be in the Same Day Funds Settlement System at DTC and, to the extent the secondary market trading in the notes is effected through the facilities of such depositary, such trades will be settled in immediately available funds. See Global Notes above.

In facilitating the sale of notes, agents may receive compensation from Wachovia or from purchasers of notes for whom they may act as agents in the form of discounts, concessions or commissions. Agents may sell notes to or through brokers or dealers, and these brokers and dealers may receive compensation in the form of discounts, concessions or commissions from the agents and/or commissions from the purchasers for whom they may act as agents. Agents, brokers and dealers that participate in the distribution of notes may be considered underwriters , and any discounts or commissions received by them from Wachovia and any profit on the resale of notes by them may be considered underwriting discounts and commissions under the Securities Act. Any such agent will be identified, and any such compensation received from Wachovia will be described, in the pricing supplement relating to those notes. Wachovia has agreed to indemnify the agents against and contribute toward certain liabilities, including liabilities under the Securities Act. Wachovia has also agreed to reimburse the agents for certain expenses.

If Wachovia offers and sells notes directly to a purchaser or purchasers in respect of which this prospectus is delivered, purchasers involved in the reoffer or resale of such notes, if these purchasers may be considered underwriters as that term is defined in the Securities Act, will be named and the terms of their reoffers or resales will be mentioned in the relevant pricing supplement. These purchasers may then reoffer and resell such notes to the public or otherwise at varying prices to be determined by such purchasers at the time of resale or as otherwise described in the relevant pricing supplement. Purchasers of notes directly from Wachovia may be entitled under agreements that they may enter into with Wachovia to indemnification by Wachovia against certain liabilities, including liabilities under the Securities Act, and may engage in transactions with or perform services for Wachovia in the ordinary course of their business or otherwise.

The agents may engage in over-allotment, stabilizing transactions, syndicate covering transactions and penalty bids in accordance with Regulation M under the Securities Exchange Act of 1934. Over-allotment involves syndicate sales in excess of the offering size, which creates a syndicate short position. Stabilizing transactions permit bids to purchase the underlying security so long as the stabilizing bids do not exceed a specified maximum. Syndicate covering transactions involve purchases of the notes in the open market after the distribution has been completed in order to cover syndicate short positions. Penalty bids permit reclaiming a selling concession from a syndicate member when the notes originally sold by such syndicate member are purchased in a syndicate covering transaction to cover syndicate short positions. Such stabilizing transactions, syndicate covering transactions and penalty bids may stabilize, maintain or otherwise affect the market price of the notes, which may be higher than it would otherwise be in the absence of such transactions. The agents are not required to engage in these activities, and may end any of these activities at any time.

The participation of Wachovia Capital Markets, LLC or any other broker-dealer affiliate of Wachovia in the offer and sale of the notes must comply with the requirements of Rule 2720 of the National Association of Securities Dealers, Inc. regarding underwriting securities of an affiliate . Neither Wachovia Capital Markets, LLC nor any other broker-dealer affiliate of Wachovia will execute a transaction in the notes in a discretionary account without the prior specific written approval of such member s customer.

This prospectus and the related pricing supplements may be used by Wachovia Capital Markets, LLC or other broker-dealer affiliates of Wachovia for offers and sales related to market-making transactions in the

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securities. Wachovia Capital Markets, LLC and other broker-dealer affiliates of Wachovia may act as principal or agent in these transactions. These sales will be made at prices related to prevailing market prices at the time of sale or otherwise.

From time to time the agents engage in transactions with Wachovia in the ordinary course of business. The agents or their affiliates may have performed investment banking services for Wachovia in the last two years and may have received fees for these services and may do so in the future. The agents and/or their affiliates may be customers of (including borrowers from), engage in transactions with, and/or perform services for the senior trustee and the subordinated trustee, in the ordinary course of business.

In addition to offering notes through the agents as discussed above, other medium-term notes that have terms substantially similar to the terms of the notes offered by this prospectus (but constituting one or more separate series of notes for purposes of the indentures) may in the future be offered, concurrently with the offering of the notes, on a continuing basis by Wachovia pursuant to the Distribution Agreement and directly to investors. Any of these notes sold pursuant to the Distribution Agreement or sold by Wachovia directly to investors will reduce the aggregate amount of notes which may be offered by this prospectus.

Selling Restrictions Outside the United States

Wachovia has taken no action that would permit a public offering of the notes or possession or distribution of this prospectus or any other offering material in any jurisdiction outside the United States where action for that purpose is required other than as described below. Accordingly, each agent has represented, warranted and agreed, and each other agent will be required to represent, warrant and agree, that it will comply with all applicable laws and regulations in force in any jurisdiction in which it purchases, offers or sells notes or possesses or distributes this prospectus or any other offering material and will obtain any consent, approval or permission required by it for the purchase, offer or sale by it of notes under the laws and regulations in force in any jurisdiction to which it is subject or in which it makes such purchases, offers or sales and Wachovia shall have no responsibility in relation to this.

With regard to each note, the relevant purchaser will be required to comply with those restrictions that Wachovia and the relevant purchaser shall agree and as shall be set out in the relevant pricing supplement.

European Economic Area

In relation to each Member State of the European Economic Area which has implemented the Prospectus Directive (each, a Relevant Member State), each agent has represented and agreed, and each other agent will be required to represent and agree, that with effect from and including the date on which the EU Prospectus Directive is implemented in that Member State (the Relevant Implementation Date) it has not made and will not make an offer of the notes to the public in that Relevant Member State, except that it may, with effect from and including the Relevant Implementation Date, make an offer of the notes to the public in that Relevant Member State:

in the period beginning on the date of publication of this prospectus which has been approved by the competent authority in that Relevant Member State in accordance with the EU Prospectus Directive or, where appropriate, published in another Member State and notified to the competent authority in that Relevant Member State in accordance with Article 18 of the EU Prospectus Directive and ending on the date which is twelve months after the date of such publication;

at any time to legal entities which are authorized or regulated to operate in the financial markets or, if not so authorized or regulated, whose corporate purpose is solely to invest in securities;

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

at any time in any other circumstances which do not require the publication by Wachovia of a prospectus pursuant to Article 3 of the EU Prospectus Directive.

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

United Kingdom

Each agent has represented and agreed, and each other agent will be required to represent and agree, that:

- with respect to notes which have a maturity of one year or more, during the period up to but excluding the date on which the EU Prospectus Directive is implemented in the United Kingdom (the Implementation Date), it has not offered or sold and will not offer or sell any such notes to persons in the United Kingdom prior to the expiring of a period of six months from the issue date of such notes except to persons whose ordinary activities involve them in acquiring, holding, managing or disposing of investments (as principal or agent) for the purposes of their businesses or otherwise in circumstances which have not resulted and will not result in an offer to the public in the United Kingdom within the meaning of the Public Offers of Securities Regulations 1995 (as amended);

- with respect to notes which have a maturity of less than one year, (a) it is a person whose ordinary activities involve it in acquiring, holding, managing or disposing of investments (as principal or as agent) for the purposes of its business and (b) it has not offered or sold and will not offer or sell any notes other than to persons whose ordinary activities involve them in acquiring, holding, managing or disposing of investments (as principal or agent) for the purposes of their businesses or who it is reasonable to expect will acquire, hold, manage or dispose of investments (as principal or agent) for the purposes of their businesses where the issue of the notes would otherwise constitute a contravention of Section 19 of the Financial Services and Markets Act 2000 (the FSMA) by Wachovia;

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

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

Japan

The notes have not been, and will not be, registered under the Securities and Exchange Law of Japan. Accordingly, each distribution agent has represented and agreed, and each other distribution agent or dealer will be required to represent and agree, that, in connection with the notes, it has not, directly or indirectly, offered, sold or delivered and will not, directly or indirectly, offer, sell or deliver any notes in Japan or to residents of Japan or for the benefit of any Japanese person (which term as used herein means any person resident in Japan including any corporation or other entity organized under the laws of Japan) or to others for re-offering, resale or delivery, directly or indirectly, in Japan or to, or for the benefit of, any resident of Japan or to any Japanese person except in compliance with any applicable laws and regulations of Japan taken as a whole. Each distribution agent agrees to provide any necessary information on notes denominated or payable in Yen to Wachovia (which shall not include the names of clients) so that Wachovia may make any required reports to the Ministry of Finance through its designated agent.

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In connection with an issuance of notes denominated or payable in Yen, Wachovia will be required to comply with all applicable laws, regulations and guidelines, as amended from time to time, of the Japanese government and regulatory authorities.

Germany

No selling prospectus *(Verkausprospekt)* within the meaning of the German Securities Prospectus Act *(Wertpapier-Verkaufsprospektgesetz)* of December 13, 1990 (as amended) has been and will be registered or published within the Federal Republic of Germany. The notes have not been offered or sold and will not be offered or sold in the Federal Republic of Germany otherwise than in accordance with the provisions of the Securities Prospectus Act.

France

This prospectus has not been submitted to the French *Commission des opérations de bourse* for approval and the notes have not and will not be offered or sold, directly or indirectly, to the public in France. Accordingly, each distribution agent has agreed that it will only offer notes in France to qualified investors, as defined under Article 6 of French Ordinance No. 67-833 dated September 28, 1967 (as amended); provided, in this case, that it shall have obtained a certificate from the investor providing an acknowledgement that: (i) the offering is a private placement in France and no prospectus has been submitted to the *Commission des opérations de bourse,* (ii) the investor is an investisseur qualifie within the meaning of Article 6 of French Ordinance No. 67-833 dated September 28, 1967 (as amended), (iii) the investor is investing for his own account, and (iv) the investor will not resell the notes in violation of French securities laws and regulations.

Switzerland

Each agent has represented and agreed, and each other agent will be required to represent and agree, that the issue of any notes denominated in Swiss francs or carrying a Swiss franc-related element will be effected in compliance with the relevant regulations of the Swiss National Bank, which currently require that such issues have a maturity of more than one year, to be effected through a bank domiciled in Switzerland that is regulated under the Swiss Federal Law on Banks and Savings Banks of 1934 (as amended) (which includes a branch or subsidiary located in Switzerland of a foreign bank) or through a securities dealer which has been licensed as a securities dealer under the Swiss Federal Law on Stock Exchanges and Securities Trading of 1995 (except for issues of notes denominated in Swiss francs on a syndicated basis, where only the lead manager need be a bank domiciled in Switzerland). The relevant agent must report certain details of the relevant transaction to the Swiss National Bank no later than the time of delivery of the notes.

The Netherlands

Each agent represented and agreed, and each other agent will be required to represent and agree, that it has not, directly or indirectly, offered or sold and will not, directly or indirectly, offer or sell in The Netherlands any notes with a denomination of less than 50,000 (or its foreign currency equivalent) other than to persons who trade or invest in securities in the conduct of a profession or business (which includes banks, stockbrokers, insurance companies, pension funds, other institutional investors and finance companies and treasury departments of large enterprises) unless one of the other exemptions or exceptions to the prohibition contained in Article 3 of the Dutch Securities Transactions Supervision Act 1995 *(Wet toezicht effectenverkeer* 1995) is applicable and the conditions attached to such exemption or exception are complied with.

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VALIDITY OF THE NOTES

The validity of the notes will be passed upon for Wachovia by Ross E. Jeffries, Jr., Esq., Senior Vice President and Assistant General Counsel of Wachovia, and for the agents by Sullivan & Cromwell LLP, 125 Broad Street, New York, New York. Sullivan & Cromwell LLP will rely upon the opinion of Mr. Jeffries as to matters of North Carolina law, and Mr. Jeffries will rely upon the opinion of Sullivan & Cromwell LLP as to matters of New York law. The opinions of Mr. Jeffries and Sullivan & Cromwell LLP will be conditioned upon, and subject to certain assumptions regarding, future action to be taken by Wachovia and the trustees in connection with the issuance and sale of any particular note, the specific terms of notes and other matters which may affect the validity of notes but which cannot be ascertained on the date of such opinions. Mr. Jeffries owns shares of Wachovia s common stock and holds options to purchase additional shares of Wachovia s common stock. Sullivan & Cromwell LLP regularly performs legal services for Wachovia. Certain members of Sullivan & Cromwell LLP performing these legal services own shares of Wachovia s common stock.

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EXPERTS

The consolidated balance sheets of Wachovia Corporation as of December 31, 2004 and 2003, and the related consolidated statements of income, changes in stockholders equity and cash flows for each of the years in the three-year period ended December 31, 2004, and management s assessment of the effectiveness of internal control over financial reporting as of December 31, 2004, included in Wachovia s 2004 Annual Report to Stockholders which is incorporated by reference in Wachovia s Annual Report on Form 10-K for the year ended December 31, 2004, and incorporated by reference in this prospectus, have been incorporated by reference in this prospectus in reliance upon the reports of KPMG LLP, independent registered public accounting firm, incorporated by reference herein, and upon the authority of said firm as experts in accounting and auditing.

LISTING AND GENERAL INFORMATION

Listing and Documents Available

Application has been made to list the notes offered by this prospectus on the Luxembourg Stock Exchange. The Luxembourg Stock Exchange has allocated to the program the number 12695 for listing purposes. The Amended and Restated Articles of Incorporation and the By-Laws of Wachovia and a legal notice relating to the issuance of the notes will be deposited prior to listing with the Registrar of the District Court in Luxembourg *(Greffier en Chef du Tribunal d Arrondissement de et à Luxembourg),* where such documents may be examined and copies obtained upon request. Copies of the above documents together with this prospectus, any pricing supplements, the Distribution Agreement, the indentures and Wachovia s Annual Report on Form 10-K for the year ended December 31, 2004 as well as all other documents incorporated by reference herein (other than exhibits to such documents, unless such exhibits are incorporated by reference therein) including future Annual Reports on Form 10-K and Quarterly Reports on Form 10-Q, so long as the notes are listed on the Luxembourg Stock Exchange, will be made available for inspection, and may be obtained free of charge, at the main office of the Luxembourg listing agent. The Luxembourg listing agent will act as a contact between the Luxembourg Stock Exchange and Wachovia or the holders of the notes. We have appointed Dexia Banque Internationale à Luxembourg as the Luxembourg listing agent for the notes.

However, notes may be issued under the program which will not be listed on the Luxembourg Stock Exchange or which will be listed on any other securities exchange as Wachovia and the relevant agent(s) may agree.

Authorization

The program has been established and the notes will be issued pursuant to authority granted by the Board of Directors of Wachovia on December 14, 2004 as such authority may be supplemented from time to time.

Material Change

As of the date of this prospectus, other than as disclosed or contemplated herein or in the documents incorporated by reference, to the best of Wachovia s knowledge and belief, there has been no material adverse change in the financial position of Wachovia on a consolidated basis since December 31, 2004. See Where You Can Find More Information above.

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Litigation

As of the date of this prospectus, other than as disclosed or contemplated herein or in the documents incorporated by reference, to the best of Wachovia s knowledge and belief, Wachovia is not a party to any legal or arbitration proceedings (including any that are pending or threatened) which may have, or have had, since December 31, 2004, a significant effect on Wachovia s consolidated financial position or that are material in the context of the program or the issue of the notes which could jeopardize Wachovia s ability to discharge its obligation under the program or of the notes issued under the program.

Clearance Systems

The notes have been accepted for clearance through the DTC, Euroclear and Clearstream systems. The appropriate CUSIP, Common Code and ISIN for each tranche of notes to be held through any of these systems will be contained in the relevant pricing supplement.

Agents

The United States Registrar and Domestic Paying Agent for the notes will be initially Wachovia Bank, National Association, located at its corporate trust office at 12 East 49th Street, 37th Floor, New York, New York 10017, Attn: Corporate Trust, or at its headquarters at One Wachovia Center, Charlotte, North Carolina, 28288-0600, United States of America.

The London Paying Agent and London Issuing Agent for the notes will be initially Citibank, N.A., located at P.O. Box 18055, 5 Carmelite Street, London, EC4Y OPA.

The Luxembourg Paying Agent and Transfer Agent for the notes will be initially Dexia Banque Internationale à Luxembourg located at 69, route d Esch, L-2953 Luxembourg.

The Listing Agent for the notes will be initially Dexia Banque Internationale à Luxembourg located at 69, route d Esch, L-2953 Luxembourg.

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ISSUER

Wachovia Corporation

One Wachovia Center

Charlotte, North Carolina 28288-0013

United States of America

UNITED STATES DISTRIBUTION AGENTS	**EUROPEAN DISTRIBUTION AGENTS**
Wachovia Securities	Wachovia Securities International Limited
ABN AMRO	Barclays Capital
Barclays Capital	Bear, Stearns International Limited
Bear, Stearns & Co. Inc.	Citigroup
Blaylock & Company	Credit Suisse First Boston
Citigroup	Goldman Sachs International
Credit Suisse First Boston	Guzman & Company
Goldman, Sachs & Co.	J.P. Morgan Securities Ltd.
Greenwich Capital Markets	Lehman Brothers
Guzman & Company	Merrill Lynch International
JPMorgan	UBS Investment Bank
Keefe, Bruyette & Woods	Utendahl Capital Partners, L.P.
Lehman Brothers	
Loop Capital Markets	
Merrill Lynch & Co.	
Samuel A. Ramirez & Co.	
Sandler O Neill & Partners	
UBS Investment Bank	

Utendahl Capital Partners, L.P.

The Williams Capital Group

UNITED STATES REGISTRAR AND

DOMESTIC PAYING AGENT

Wachovia Bank,
National Association

One Wachovia Center

Charlotte, North Carolina 28288-0600

United States of America

LONDON PAYING AGENT

AND LONDON ISSUING AGENT

Citibank, N.A.

P.O. Box 18055

5 Carmelite Street,

London EC4Y OPA

LUXEMBOURG PAYING AGENT,

LISTING AGENT

AND TRANSFER AGENT

Dexia Banque Internationale à Luxembourg

69, route d Esch

L-2953 Luxembourg

LEGAL ADVISORS

To the Issuer

As to United States Law:

Ross E. Jeffries, Jr., Esq.

Senior Vice President and

Assistant General Counsel

Wachovia Corporation

One Wachovia Center

Charlotte, North Carolina 28288-0630

United States of America

To the Distribution Agents

As to United States Law:

Sullivan & Cromwell LLP

125 Broad Street

New York, New York 10004

United States of America

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$5,461,000

Wachovia Corporation

ASTROS[SM]

(ASseT Return Obligation Securities)

Linked to the Metals-China Basket

due January 28, 2009

PROSPECTUS SUPPLEMENT

July 21, 2005

Wachovia Securities