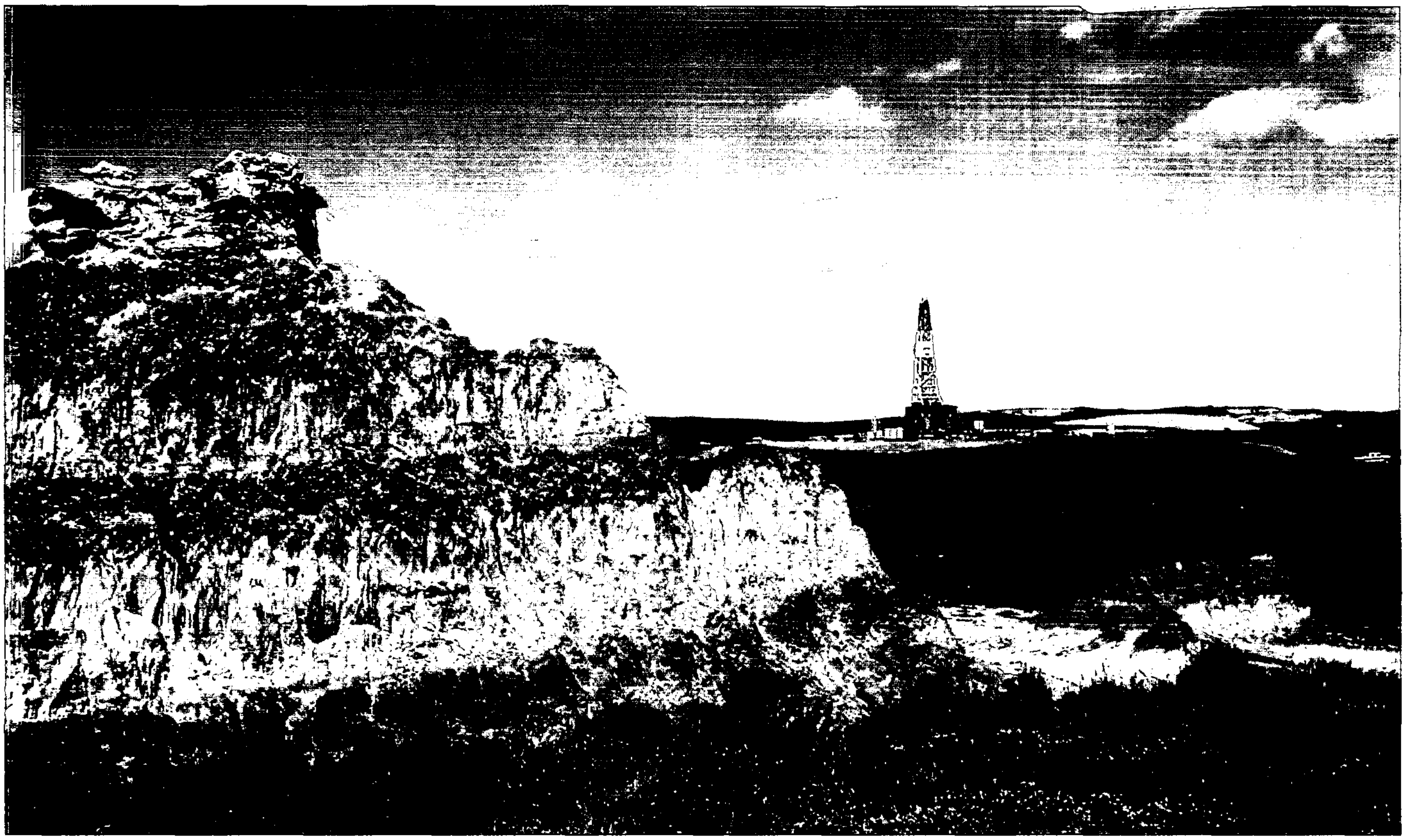
P.E. 12-31-04

APR 15

Bill Barrett Corporation



2004 Annual Report | Discovery Through Teamwork

Contents

Bill Barrett Corporation applies its expertise and strong balance sheet to its extensive property base to generate shareholder value by pursuing an aggressive exploration strategy to profitably find and develop natural gas in the Rockies. We approach our business with four core values:

INTEGRITY in the way we conduct our business, respect the environment, and analyze our opportunities

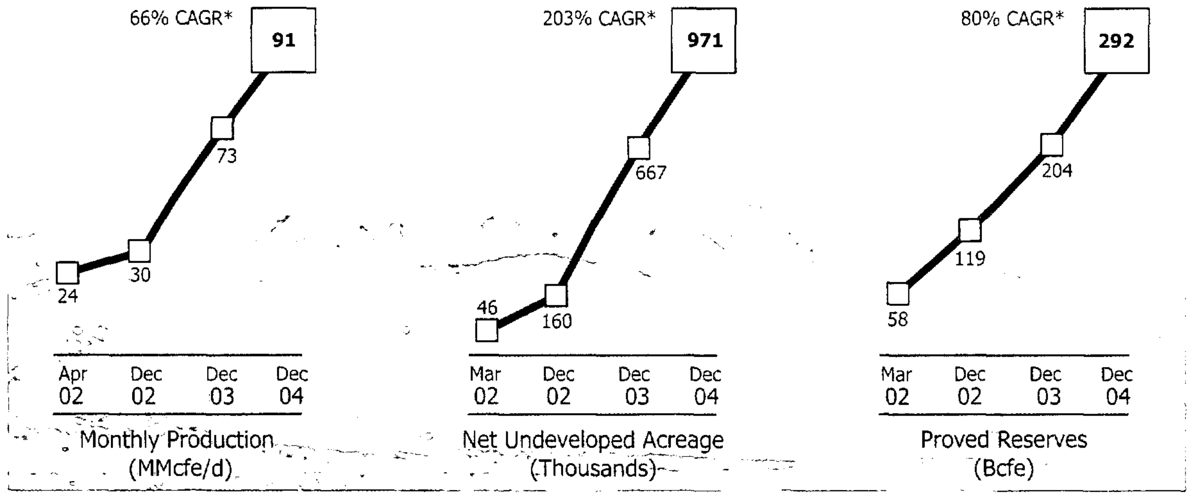
GROWTH in production, reserves, and our share price

TEAMWORK in the way we manage our business and work with our partners

ALLEGIANCE to our investors, employees, suppliers, and the communities in which we operate

Bill Barrett Corporation

Cover Photo: Wind River formation outcrop and drilling rig in the Wind River Basin



*CAGR: Compounded Annual Growth Rate

Summary Operating and Financial Information

	2002	2003	2004
Proved Reserves and Acreage			
Natural Gas, Bcf	101.8	180.9	257.8
Oil, MMBbls	2.9	3.9	5.7
Natural Gas Equivalents, Bcfe(1)	119.1	204.2	292.3
Percent Developed	75%	63%	61%
Percent Natural Gas	85%	89%	88%
Pre-Tax PV-10, millions	$179	$521	$593
Net Undeveloped Acreage (rounded)	160,000	667,000	971,000
Production			
Average Daily Production, MMcfe	23.6	50.1	86.6
Percent Natural Gas	97%	89%	91%
Average Realized Prices			
Natural Gas Prices, net of hedges, $/Mcf	$2.39	$4.03	$5.10
Oil Prices, net of hedges, $/Bbl	$25.39	$28.85	$39.49
Operating Statistics			
Reserve Replacement	N/A	565%	378%
Capital Expenditures and Acquisitions, millions	$167	$186	$347
Producing Wells, gross/net	208/160	540/343	743/553
Wells Drilled, gross/net	7/6	180/154	287/259
Financial Data, $/Mcfe			
Production Revenue	$2.44	$4.12	$5.23
Lease Operating Expenses and Gathering and Transportation	$0.37	$0.66	$0.65
Production Taxes	$0.31	$0.54	$0.63
General & Administrative, excluding non-cash stock-based compensation	$0.84	$0.78	$0.57
Depletion, Depreciation, and Amortization	$1.40	$1.68	$2.15
Discretionary Cash Flow(2)	$0.98	$2.09	$3.23

(1) One Barrel of oil is the energy equivalent of six Mcf of natural gas
(2) Non-GAAP Measure, see "Glossary"

Executive management routinely reviews projects with team members

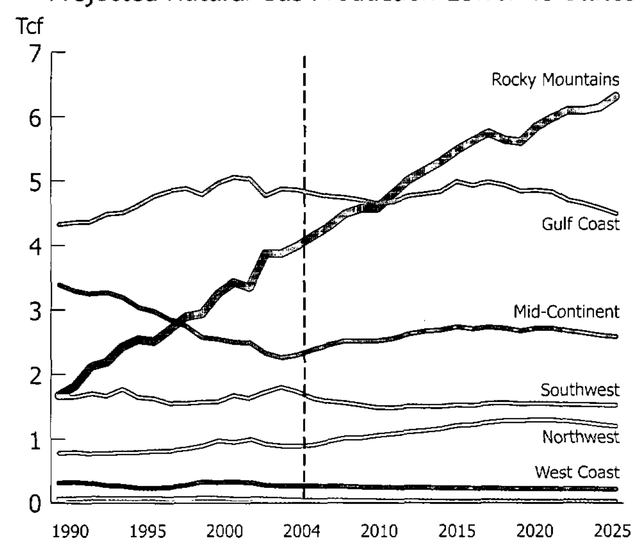
Letter to Shareholders

In your hands is our first annual report as a public company, representing both our hard work over the past three years and a benchmark for our future performance. Having been involved with the formation of several public companies, our team has experienced firsthand the value of access to the public capital markets to a company with an aggressive growth strategy like ours. Our experience is that going public is the best way to access the long-term capital needed to grow an exploration and production company.

Our initial public offering effort consumed much of 2004 for many of our employees, and we are proud of what they accomplished. Teamwork starts at the top at Bill Barrett Corporation. President Fred Barrett, Chief Operating Officer Frank Keller, and Chief Financial Officer Tom Tyree helped build our operations to critical mass and provided the guidance needed for the complex undertaking of going public and managing a public company. Bob Howard, Executive Vice President — Finance and Investor Relations; Francis Barron, Senior Vice President — General Counsel; and Dominic Bazile, Senior Vice President — Operations, were all instrumental in managing our growth and achieving our performance objectives, while ensuring a smooth transition from a private to a publicly-held corporation. The year saw us increase production by 73%, reserves by 43%, and discretionary cash flow by 168%. As a result, we enjoyed a strong reception by Wall Street with an IPO deemed highly successful by several measures.

Investors' positive reaction to the Company suggests that many people find our strategy compelling. Our focus is on exploration and development in the Rocky Mountains, the only gas producing province in the country expected to show meaningful production growth over the next 20 years. We estimate that as much as 85% of the recoverable natural gas in the Rockies has not yet been tapped, and in an industry constantly developing new technologies, even more reserves could ultimately become recoverable.

Projected Natural Gas Production-Lower 48 States



Source: Dept of Energy, EIA; January 2004

Executive Management Team: Tom Tyree, Bill Barrett, Frank Keller, and Fred Barrett

Further defining our strategy is our experience and willingness to explore for new reserves. This exploration strategy, combined with a land inventory of nearly a million net acres, positions us very well to help our industry meet the demand for natural gas in our country, which is expected to grow approximately 60% over the next 20 years.

Much of the future exploration in the Rockies will be for unconventional resources, such as basin-centered tight gas sands (e.g., our Piceance, Uinta, Big Horn, and Wind River Basin project areas), coal-bed methane (e.g., our Powder River Basin project area), biogenic gas (e.g., our Tri-State project area), and fractured shales (e.g., our Paradox Basin project area). Upwards of 70% of our current project inventory targets unconventional gas. These are repeatable plays with long reserve lives, relatively low risk, and the potential for substantial reserves. The emergence of unconventional gas in the Rockies is a factor of growing importance to our country's energy future, and it coincides with the development of technologies making that resource recovery possible.

We still explore for conventional reserves, utilizing advanced technologies such as 3-D seismic surveys that we interpret to show large potential structures in projects such as our West Tavaputs development in the Uinta Basin, as well as deeper opportunities in our Cave Gulch and Waltman areas in the Wind River Basin. Rigless completions, the ability to simultaneously complete multiple zones, and the application of horizontal drilling technology have all helped the Company to maximize resource recovery while increasing efficiency and managing costs in a rising cost environment.

Expansion of the Rockies' pipeline network and other infrastructure development has reduced certain marketing risks that confronted the industry in the past. New takeaway capacity built during the last two years has limited the historically large price differential between Rockies gas and NYMEX (which was almost always to the detriment of Rockies producers) by providing the pipeline capacity to consistently deliver more gas to markets outside the Rocky Mountain region. We have further reduced price risk through hedging more than 40% of our production to help deliver more predictable cash flows.

We have improved our property base by pursuing lands in areas that strengthen existing positions and by simply beating the competition in leasing in new prospective areas. Our aggressive lease acquisitions over the past three years have allowed us to avoid some of the increased prices all operators are seeing for acreage today in the Rockies. As a result, the current value of our property position far exceeds our cost basis in these properties. More importantly, we have identified over six years of future development drilling locations on these lands. From an exploration standpoint, these positions give us the potential for plays that will carry the Company even further into the future.

Fred Barrett and other members of the management team ring the opening bell at the New York Stock Exchange

Photo: New York Stock Exchange

For 2005, we have budgeted $276 million in capital expenditures to explore and develop our property base. Above and beyond this investment, we have developed a joint exploration strategy whereby we seek to enter into joint exploration agreements, which include joint drilling obligations, with high-quality, exploration-oriented industry partners. The primary objective of this strategy is to increase our exposure to potential reserves and production, while recouping a portion of our initial investment through the partial sale of our interests in certain exploration projects. In connection with these anticipated joint exploration agreements, we expect to sell approximately 30% to 60% of our working interest, depending on the project. We plan to use the proceeds from these ventures to expand our exploration activities beyond those contemplated in our current capital expenditure budget. This is a strategy we have successfully applied through the years to help us meet our objective of long-term, sustainable growth.

High commodity prices have caused increased costs in oil field services, reflected primarily in the pricing and availability of rigs and crews. We have leveraged our large capital program, our strong financial position, and our supplier relationships to create economies of scale with our service providers in an effort to mitigate some of the cost increases. These are the things we do to stay competitive in a high-demand/high-cost environment for field services.

How do we know when we are being successful? We have shown we can grow reserves, production, and cash flow year after year. Since early 2002, we have increased our reserves 80% on a compound annual basis, our production 66%, and our discretionary cash flow 119%. But the growth potential of our business is only part of the reason I came out of retirement to lead this Company. We have a lot of help around here from a group of highly experienced oil and gas professionals. From a management and cultural perspective, our employees share the vision of working together to create a premier E&P company in the Rockies. Teamwork, knowledge, and experience are powerful forces in an organization, especially when fueled by an entrepreneurial mindset that is both creative and competitive. It is a privilege to work with the exceptional group of employees we have here at Bill Barrett Corporation.

Rarely have we ever encountered such a confluence of circumstances that make this business so invigorating today: extensive geologic opportunity, strong commodity prices, new technologies, and access to capital. On behalf of all of us at Bill Barrett Corporation, I assure you we will do our best to take advantage of these opportunities.

Sincerely,

William J. Barrett

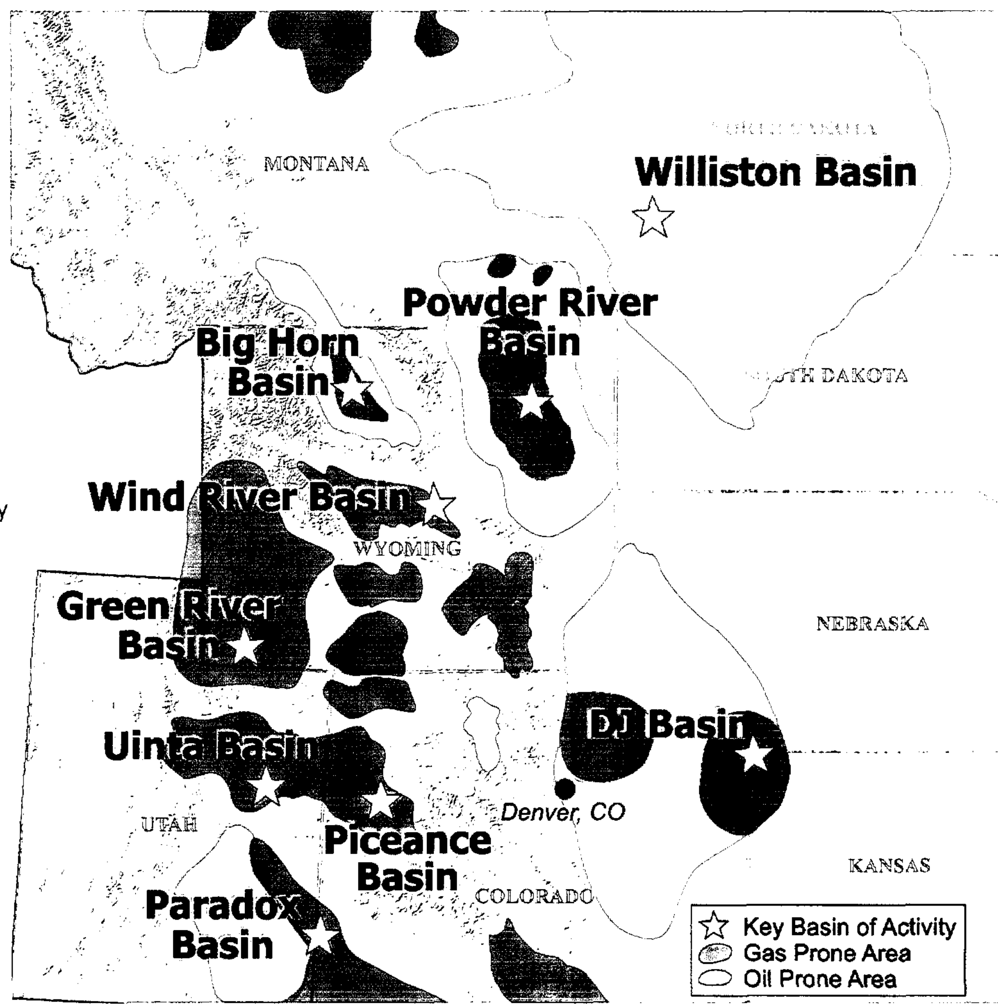
William J. Barrett

Chief Executive Officer and Chairman of the Board

March 18, 2005

Rocky Mountain Front Range, Colorado

Areas of Operation



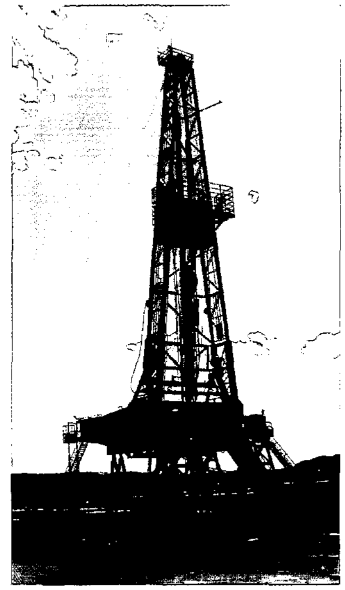
Detailed project maps available at www.billbarrettcorp.com

Bill Barrett Corporation is an exploration and production company focused on finding natural gas throughout the Rocky Mountains of the United States. In the three years since its formation, the Company has built an extensive multi-year drilling inventory with nearly one million net undeveloped acres (as of year-end 2004) leased across eight Rocky Mountain states.

Led by a senior management team with nearly 300 years of collective experience, the Company is leveraging its exploration and operational expertise to grow reserves and production through the drillbit.

The Company assembles multiple high-impact, high-return exploration plays heavily weighted toward unconventional projects

Roughnecks racking pipe during a bit-trip in the Uinta Basin



Deep drilling rig in the Wind River Basin

Proved Reserves by Basin as of December 31, 2004		
Area	Bcfe	%
Piceance Basin	89	30%
Uinta Basin	49	17%
Wind River Basin	83	28%
Powder River Basin	40	14%
Williston Basin	31	11%
Total proved reserves	292	100%

Production by Basin for December 2004		
Area	MMcfe/d	%
Piceance Basin	6	7%
Uinta Basin	17	19%
Wind River Basin	41	45%
Powder River Basin	21	23%
Williston Basin	6	6%
Total production	91	100%

such as basin-centered/tight gas sand plays, coalbed methane (CBM), biogenic gas, and fractured shales, as well as conventional concepts such as structural/stratigraphic plays. Though focused on natural gas, the Company will capitalize on opportunities in oil when geology and market conditions merit.

The Company has budgeted $276 million for capital expenditures in 2005. This capital expenditure budget includes drilling and recompletion activity in development areas, drilling activity in exploratory areas, additional leasing, installation of facilities and infrastructure, geologic and geophysical activities, and other corporate expenditures. More than 85% of the 2005 capital expenditure budget is slated for activities in the Piceance, Uinta, and Wind River Basins.

Acreage Inventory as of December 31, 2004

	Undeveloped Acres	
Area	Gross	Net
Wind River Basin	388,172	165,946
Williston Basin	179,259	113,403
Uinta Basin	134,036	96,672
Paradox Basin	15,160	10,004
D-J Basin(1)	367,426	346,022
Powder River Basin	96,717	59,587
Piceance Basin	12,812	10,031
Green River Basin	13,297	7,977
Big Horn Basin	192,799	145,442
Other Rockies	51,838	16,002
Total acreage	1,451,516	971,086

(1) Subsequent to December 31, 2004, the Company entered into a joint exploration agreement which included the sale of a 50% interest in its D-J Basin project. As of March 1, 2005, the Company owned 173,011 net undeveloped acres in that project area.

The exploration and development discussion on the following pages details key Company efforts for 2005.

Heliportable 3-D seismic equipment being used in a seismic survey conducted in the Uinta Basin

Piceance Basin

The Company purchased the Gibson Gulch property in September of 2004 for approximately $137 million. The acquisition included 46 Bcfe of estimated proved reserves. It also marked a return to the Piceance Basin in northwest Colorado, a region where several members of Bill Barrett Corporation staff worked through the 1980s and 1990s with considerable success at Barrett Resources Corporation.

By the end of 2004, Gibson Gulch was generating 7% of the Company's total daily production. In addition to the acquisition cost, the Company spent $14.5 million in Gibson Gulch during 2004, approximately $7 million of which was allocated to non-operated wells; the remainder was spent on recompletion work, leasing, and compression upgrades. The Gibson Gulch property contains 30% of the Company's 2004 year-end reserves. Company activities are focused on the eastern side of a continuous 25-mile trend of basin-centered gas trapped in the tight sandstones of the Mesaverde formation.

The Company has allocated $120 million to drill 95 wells and recomplete 12 wells in the Piceance Basin in 2005. Year-round operations are permitted within the Gibson Gulch area. Current drilling on the Company's Piceance Basin acreage is on 20-acre well density, but the Company has received approval for 10-acre density throughout its acreage position. Plans for 2005 include a 25 square mile 3-D seismic survey and several test wells to help Company geoscientists evaluate those areas in the Piceance where economic quantities of gas are recoverable on 10-acre density. If the test wells are successful, that 10-acre density could equate to over 1,000 additional gross drilling locations. The Company's working interest in the majority of the wells planned for drilling in 2005 is approximately 99%.

Uinta Basin

The Uinta Basin, in northeast Utah, presents both development and exploration potential for the Company. Bill Barrett Corporation owns 5,811 net developed acres and has 19 net producing wells in the basin. The Company's undeveloped acreage, at March 1, 2005, consists of 258,422 net acres, including 161,750 acres subject to drill-to-earn agreements. The Company booked 49 Bcfe of estimated proved reserves at the end of 2004, which represents 17% of year-end reserves. The Uinta Basin produced 19% of our December production or 17 MMcfe per day.

The Company spent $47 million in the basin in 2004 for a 3-D seismic survey, infrastructure upgrades, and to drill ten wells. Two


Laying seismic cable in the Uinta Basin


Drilling rig in the Uinta Basin

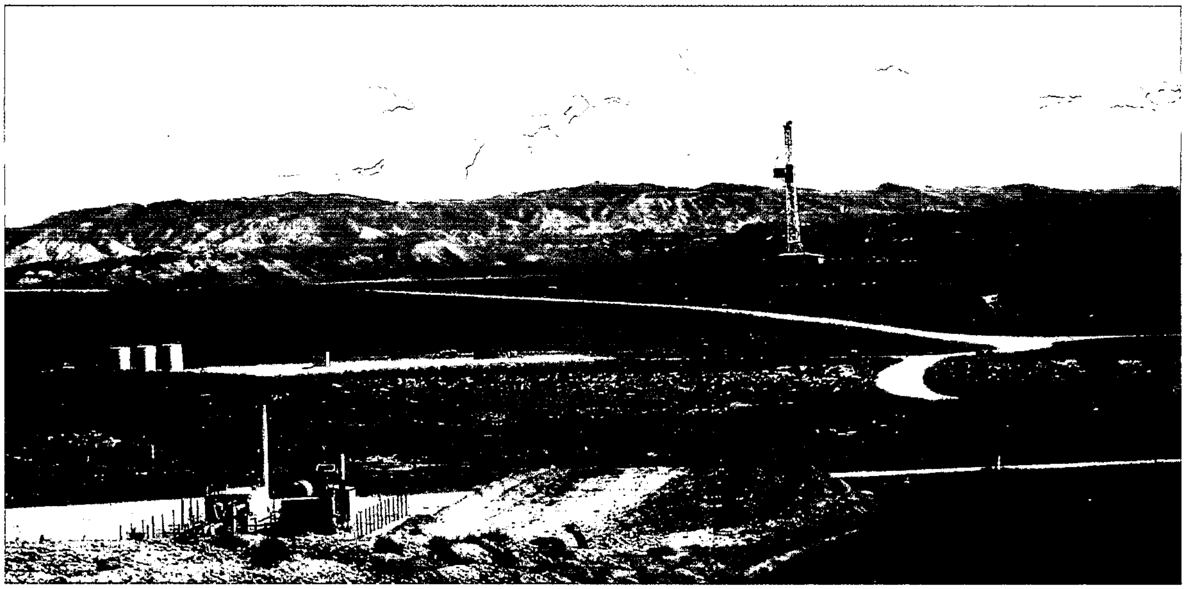
of the wells were successfully completed and six are awaiting completion in the spring of 2005 following the end of winter stipulations imposed by the Bureau of Land Management. The ninth well, located in the Brundage Canyon field, has been abandoned pending further evaluation of a 3-D seismic survey and assessment of the optimal completion technology for the tight gas sandstone encountered in the well.

We are encouraged by the presence of several large structural and stratigraphic features identified through our 86 square mile 3-D seismic survey shot this past summer in the West Tavaputs area northeast of Price, Utah. This data, combined with our successful drilling efforts, make this area the focus of our 2005 capital budget for the Uinta Basin. We plan to spend $52 million in West Tavaputs to drill 17 wells, complete the six wells drilled in 2004, recomplete four wells, and finish the upgrades and extensions to the gathering system. We are also planning a deep exploratory well to test one of the features identified on the 3-D seismic survey.

To the southeast of West Tavaputs, we were successful in drilling and completing our tenth and final drilling commitment well in Hill Creek field, where we have a 60% net revenue interest. This well has produced more than 1 Bcfe in about four months. We are evaluating our option to participate in 50% of our partner's interest in nine additional wells in a second phase of activity at Hill Creek field.

The Company plans to acquire 21 square miles of 3-D seismic data in an extension from Hill Creek that we call Tumbleweed. A separate 3-D survey on a second Hill Creek extension prospect called Cedar Camp has been completed and is being processed. The seismic data helped define the location for a deep Cedar Camp well drilled in early 2005 targeting the Wingate and Dakota formations. Results from this well are expected in the second quarter of 2005. A second well targeting the same formations is being drilled in the second quarter of 2005.

The final component of our 2005 program for the Uinta Basin stems from a development agreement the Company signed with an industry partner and the Northern Ute Indians in May 2004. The agreement covers the Lake Canyon prospect, one of the largest unexplored acreage blocks in the entire Rocky Mountain region. Lake Canyon lies at a structural level similar to Natural Buttes field, a prolific basin-centered gas accumulation producing from the Mesaverde and Wasatch formations located in the eastern part of the Uinta Basin. With nearly 158,470 net acres, the Lake Canyon block is bordered on its northern side by the giant Altamont/Bluebell field and on its eastern side by the Brundage Canyon field. Prior dealings with the Northern Ute tribe in Brundage Canyon helped serve as the basis of this new



Storage tanks, compressor and drilling rig in our Wind River Basin project area

partnership with the Ute Tribe, which has the right to join in any well as a 25% working interest partner.

The Lake Canyon agreement gives the Company a 75% working interest (before considering the right of the Ute Tribe to participate) in the deep rights to explore for basin-centered Mesaverde tight gas sandstone and a 25% working interest down to a total depth of 6,200 feet to explore for oil in the Green River formation.

Efforts throughout the Uinta in 2005 include $66 million for drilling 23 new wells, completing six wells drilled in 2004, recompleting four wells, and acquiring 75 square miles of 3-D seismic in two surveys.

Wind River Basin

The Wind River Basin, located in central Wyoming, has been the Company workhorse the past three years. As of December 31, 2004, we had 134 net producing wells and more than 165,000 net undeveloped acres, providing us a large inventory of development and exploration locations. Like the Piceance, this is a basin where our Company geoscientists and operations personnel have decades of experience, and we have been able to grow production consistently here as we build prospects elsewhere. Today, the basin remains our largest producing area with active infill and field extension development drilling programs as well as exploration opportunities in eight project areas.

Our net daily production from the Wind River Basin was 41 MMcfe per day in December 2004, accounting for 45% of the Company's net daily production. Reserves of 83 Bcfe represent 28% of the Company's year-end reserves. In 2004, the Company invested $96 million, drilling a total of 56 development wells at the Cave Gulch, Cooper Reservoir, and Wallace Creek fields. Infill and field extension efforts in Cooper Reservoir and Cave Gulch resulted in 37 successful wells out of 39 drilled. Efforts to extend production away from the main field area in Wallace were less successful, so we curtailed drilling there in order to re-examine potential development opportunities.

On the exploration front, the Company drilled 13 exploratory wells in the Wind River Basin in 2004. The Company has enjoyed some initial success in the Talon prospect, where we are currently producing gas and oil from one Lance well and four Fort Union wells.

Initial efforts to test the Tensleep formation in Waltman Arch were disappointing, leading us to record a dry hole expense of $7.9 million in the fourth quarter of 2004 on our initial test well. Because we believe issues with the well had more to do with

Tracy Galloway, Senior Geologist, and Terry Barrett, VP Exploration, reference a Powder River Basin map at the Cat Creek prospect

perfecting completion techniques than with the actual geology, we will continue to explore options such as a joint exploration agreement to further facilitate development of this area. That was our approach to a 16,600 foot Lance formation test well in the East Madden field in an area called Hitchcock Draw, where we have drilled a deep exploratory well and set production casing with an industry partner. We expect completion results later in the second quarter of 2005.

The Company is allocating more than $55 million to drill 26 new wells and recomplete five wells in the Wind River Basin in 2005. This figure excludes proceeds and additional drilling expected from a joint exploration package we are circulating to industry partners to further evaluate five key projects along the Waltman Arch.

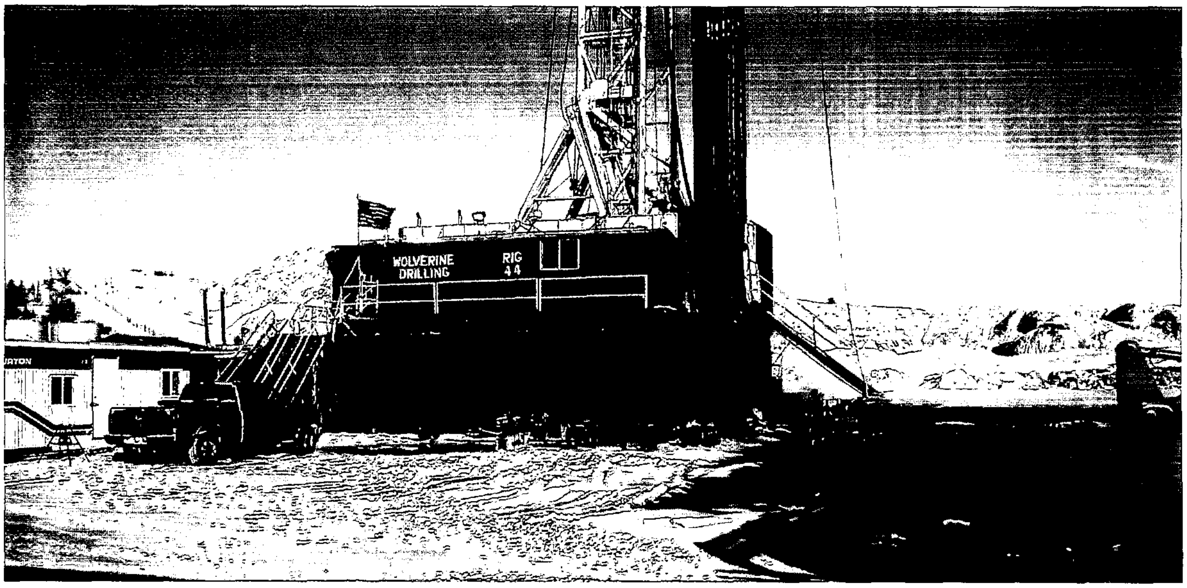
Powder River Basin

With 23% of the Company's production for December 2004, the Powder River Basin, located in northeastern Wyoming, is Bill Barrett Corporation's second highest producing area. Since acquiring its first acreage in the basin in 2002, the Company has grown production to 21 MMcfe per day in December 2004. We reported 40 Bcfe of reserves, or 14% of 2004 total reserves, in the Powder River Basin. As of December 31, 2004, we leased more than 16,000 net developed acres and approximately 60,000 net undeveloped acres in the basin. Our activity in the Powder River Basin is focused on two CBM targets, the Wyodak coal seam and the Big George coal seam, with several projects within each of these formations.

All of our production in the Powder River Basin is from CBM wells, a type of unconventional gas recovery characterized by lower risk, lower drilling costs, and lower production rates. All of the 206 CBM wells drilled in 2004 were successful, both from a production

Gary Marquiss, rancher, and Bill Mitchell, BBC landman, shake hands over surface-use agreement

Photo: Rocky Mtn. Energy Reporter



Winter drilling in the Williston Basin

and economic standpoint. The Company had particularly good performance in the Palm Tree area in 2004, where we drilled 82 wells in the southern end of the Big George fairway. Of the remaining 124 wells drilled in the Powder River Basin, 88 were drilled in the Porcupine prospect targeting the Wyodak fairway east of the Big George fairway. The Wyodak fairway also is the site of the Company's Tuit prospect, where we drilled 23 wells in 2004. The remaining 13 wells were drilled in the Big George fairway in the emerging Dead Horse and Cat Creek prospects. The Company has another prospect in the Big George fairway, Willow Creek, where it is considering some potential activity this year.

Challenges facing CBM development are the complex regulatory and permitting requirements and the treatment and disposal of water produced with the natural gas. Bill Barrett Corporation has several experts, each with more than a decade of CBM experience in the Powder River Basin, to manage these critical components of operations. Their efforts resulted in our Company procuring more than 300 permits to drill wells on federal acreage in 2004, enough to support 18 months of drilling.

Our 2005 budget for the Powder River Basin calls for capital spending of slightly over $16 million to drill 218 wells. Approximately $4 million in additional spending is planned to expand our production and gathering facilities and to strengthen the Company's lease position.

Williston Basin

The Williston Basin, source of the majority of Bill Barrett Corporation's oil production, contains approximately 11% of the Company's year-end reserves. Bill Barrett Corporation owned 7,472 net developed acres and more than 113,000 net undeveloped acres in the Williston Basin as of December 31, 2004. The Company has both exploration and development projects targeting the Madison, Bakken, and Red River formations in the Williston, which covers portions of Montana, North Dakota and South Dakota. The Company spent $19.8 million in the Williston in 2004 to acquire additional acreage and drill nine horizontal oil wells, eight of which were successful. Five of the successful wells were Madison formation tests in North Dakota, all of which have been completed as producing oil wells with initial production rates ranging from 50 Bopd to 125 Bopd per well, with minimal initial decline.

In Montana in 2004, we drilled and completed four additional horizontal Madison wells, three of which were successful. In addition to the two successful Red Bank field wells, we drilled a successful horizontal Madison exploratory well in our Target area, just north of Red Bank. This success prompted the Company to budget an additional development well in Red Bank field and three development wells surrounding the Target field discovery

Tri-State survey marker in the D-J Basin


Laying seismic recording cable

in 2005, where the Company controls 12 surrounding 640-acre sections with working interests ranging from 90-100%.

We are attempting to expand the Madison formation play into North Dakota with two prospective exploration trends, the Red Bank Extension (25,517 net acres) and Indian Hills (4,038 net acres). The Company plans to promote the drilling of exploratory wells in both areas, retaining operations and a 50% working interest. An additional Madison development well in the Rival trend within North Dakota also is planned.

Two exploratory wells targeting the Red River B formation are planned for 2005 in our Grand River area along the North and South Dakota border (17,356 net acres), and an additional exploratory well in the Bakken formation in our Red Water prospect of Montana (10,981 net acres). We will seek an industry partner for these projects, with Bill Barrett Corporation retaining operations and a 60% and 50% working interest, respectively. The Company has allocated $9.2 million in 2005 to drill six development wells in the Williston Basin. Proceeds from planned exploration agreements with industry partners will fund additional exploratory wells.

Denver-Julesburg Basin

Following nearly two years of work to assemble a massive lease block of 346,000 net acres in the basin, we entered into a 50/50 joint venture agreement with an industry partner to explore, drill, and develop the Tri-State area. Two exploratory wells targeting biogenic gas in the Niobrara formation, with locations selected using detailed seismic interpretation and evaluation, should be drilled and completed in the second quarter of 2005. The Company also plans to survey 525 linear miles of 2-D seismic and 180 square miles of 3-D seismic in the basin during 2005.

Green River Basin

The Green River Basin, located in southwestern Wyoming, is one of the most prolific gas-producing basins in the Rockies. Home to both the Pinedale Anticline and Jonah field, it is also one of the most competitive.

The Company started work in this basin in 2004, leasing undeveloped acreage and conducting various exploratory activities in Antelope Hollow. Our industry partner spud a deep exploratory well targeting the Dakota formation in February 2005. We expect preliminary results from the well sometime in late spring. We

Seismic source hole drilling

Seismic crewman

own a 40% working interest in the well and have allocated $2 million of our 2005 capital expenditure budget to drill this exploratory well.

Paradox Basin

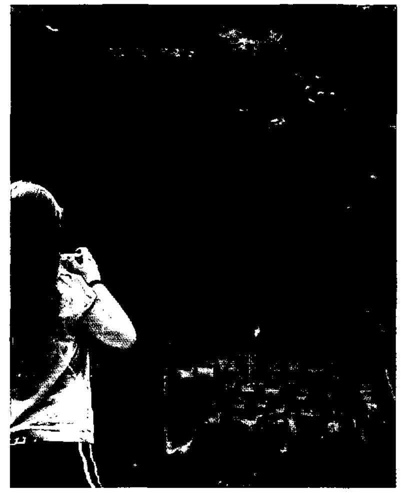
The Paradox Basin is located in southwestern Colorado and southeastern Utah. Traditionally considered an oil-prone basin, 3-D seismic surveys and new drilling fluid technology have helped establish new gas play concepts in the basin.

Our current focus in the Paradox Basin is the Pine Ridge exploratory prospect, where we are just starting to explore for gas fields in stratigraphic traps. We held 1,960 net acres under lease at year-end 2004 and intend to build our acreage position in this play through additional leasing and acquisitions. We are continuing our work with the U.S. Forest Service and the Bureau of Land Management on permits for a 20 square mile 3-D seismic survey we have targeted for 2005.

In 2004, we acquired 8,044 net acres in the Yellow Jacket prospect. This prospect will target natural gas from a fractured shale reservoir at depths of 4,500 feet to 6,500 feet. Our capital expenditures for 2005 will be $0.8 million to lease more acreage.

Big Horn Basin

The Big Horn Basin, located in north central Wyoming, is the site of another emerging exploratory play for the Company. Like the Paradox Basin, the Big Horn Basin was traditionally considered an oil-prone basin. We feel there is considerable potential for both conventional stratigraphic and structural gas plays, as well as unconventional basin-centered gas plays, in the basin. At year-end 2004, we had leasehold interests in nearly 193,000 gross and over 145,000 net undeveloped acres in the Big Horn Basin.



Bill Barrett Corporation has invested nearly $1 million to inventory and protect the cultural artifacts found in our West Tavaputs seismic project. By re-locating the canyon road, people can contemplate the famed Hunter Panel Petroglyph without having to worry about traffic or noise. Our investment also means archeologists and anthropologists now know more about the historic artifacts in this area than ever before.

Photos: Utah Trust Lands Administration-Normalee McMichael and Rick Shaw

Environmental Awareness and Community Involvement

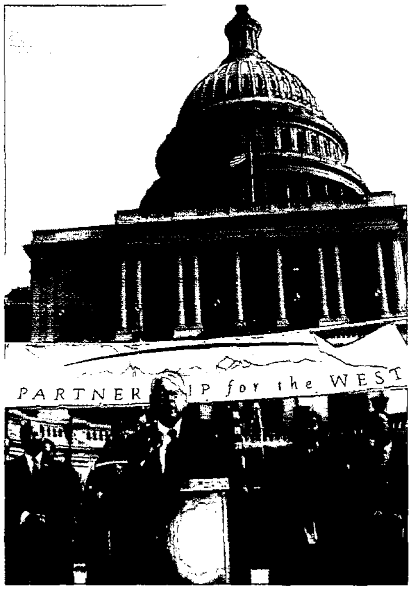
The Rockies are world-renowned for their beauty and sense of place. The employees of Bill Barrett Corporation know that we are lucky to be living, working, and raising families in such a setting. With this privilege comes the responsibility to develop resources in a way that assures the Rockies remain a place of beauty for future generations.

The region's role in the country's energy future is considerable. The Rockies are projected to be the country's biggest gas producing province over the next 20 years. Perhaps more importantly, production from the region is expected to grow rapidly during that time, meaning the Rockies represent the future for generating the energy required to keep the world's strongest economy healthy. On a local level, we believe that efficiently growing our Company depends in part on our ability to promote understanding of the industry and the benefits responsible energy development brings to society. This helps us gain acceptance of our business practices in the communities in which we operate.

We know our business has environmental and economic impacts, as do all forms of energy development. But a typical gas well pad, which is four feet high and covers the area of a two car garage, provides the same amount of energy as would eight wind turbines, each over 200 feet high, spread across half a mile.

In many of the Rocky Mountain communities where we operate, oil and gas activity is the single biggest contributor to county budgets in the form of royalty and severance taxes. These contributions fund new roads, schools, and special recreation districts, while keeping taxes low for residents. Our activities also boost local economies through job creation, purchase of goods and services, and other local business activities. Our goal in our support of the communities hosting us is to contribute to those activities that help protect the quality of life unique to the Rockies. Our level of commitment to these communities is reflected by our support in many areas: the arts, high school athletics, youth 4-H and rodeo, education, environmental protection, cultural promotion, and historic preservation. Our employees and contractors live in these communities too, and healthy communities and healthy businesses go hand in hand.

Our Company has developed operational excellence by applying its expertise beyond merely drilling to include mitigation of environmental impacts throughout all phases of resource development. We work to reduce surface disturbance, to protect and, where feasible, even enhance wildlife habitat. We have led the development of best management practices to protect air and water resources, to reduce traffic and noise, and to prevent leaks and spills. Additional efforts include funding of



Bill Barrett urges members of Congress to pass comprehensive energy legislation

Producing gas well in the Piceance Basin

wildlife, cultural, and historical resource studies in areas in which we operate. Bill Barrett Corporation has developed a strong reputation for environmental protection. We work with federal, state, and local officials to comply with the strictest environmental regulations in the world. A standard project, for instance, must adhere to the National Environmental Policy Act, the Clean Air Act, the Clean Water Act, the Endangered Species Act, and the Resource Conservation and Recovery Act, in addition to state and local laws pertaining to natural resource development, zoning, transportation, water management, and more. These regulations often require suspension of operations for months at a time to accommodate wildlife. Our Stone Cabin 3-D seismic survey involved mitigation, consultation, and coordination with 12 Native American tribes, four state agencies, three federal agencies, 14 other organizations, and three county governments.

Technological innovation is another tool for reducing environmental impact. Horizontal and directional drilling allows several wells to be drilled from one well pad and 3-D seismic surveys reduce the number of wells drilled by increasing the likelihood of finding natural gas or oil. Multi-zone completion techniques help maximize resource recovery from a single well, while more efficient operations reduce emissions from natural gas that were traditionally vented during completion of a well.

Regulatory compliance is burdensome and increases the cost to find and produce oil and natural gas. But Bill Barrett Corporation is staffed and structured to manage the regulatory process, work with policy makers, and develop and share best management practices that protect the environment while providing new energy supplies essential to America's economic prosperity and national security. Natural gas, after all, is the cleanest burning hydrocarbon. Perhaps the least known natural gas benefit is that it is the most efficient hydrocarbon energy source as well. In other words, a higher percentage of natural gas extracted from beneath the ground is converted to energy for our consumption than from any other hydrocarbon, which equates to less waste and more energy.

These efforts are hard to track to the bottom line but are immediately recognizable in bettering lives. We know being a good neighbor is good business.


Board of Directors standing: Philippe Schreiber, Rich Aube, Henry Cornell, Mike Wiley, Bill Barrett, Fred Barrett, Roger Jarvis, Frank Keller and Randy Stein. Seated: Jim Fitzgibbons and Jeffrey Harris

Board of Directors

William J. Barrett
Chairman and Chief Executive Officer
Bill Barrett Corporation

J. Frank Keller
Vice Chairman and Chief Operating Officer
Bill Barrett Corporation

Fredrick J. Barrett
President, Bill Barrett Corporation

Richard Aube
Partner, JPMorgan Partners, LLC

Henry Cornell
Managing Director, Goldman, Sachs & Co.

James M. Fitzgibbons
Retired Chairman of the Board, Davidson Cotton Company

Jeffrey A. Harris
Managing Director, Warburg Pincus LLC

Roger L. Jarvis
Chief Executive Officer, Spinnaker Exploration Company

Philippe S.E. Schreiber
Business Consultant and Attorney

Randy Stein
Tax and Business Consultant

Michael E. Wiley
Retired Chief Executive Officer, Baker Hughes Incorporated

Officers

William J. Barrett
Chief Executive Officer and Chairman of the Board

J. Frank Keller
Chief Operating Officer and Vice Chairman

Fredrick J. Barrett
President

Thomas B. Tyree, Jr.
Chief Financial Officer

Robert W. Howard
Executive Vice President – Finance and Investor Relations

Francis B. Barron
Senior Vice President – General Counsel and Secretary

Dominic J. Bazile II
Senior Vice President – Engineering and Operations

Terry R. Barrett
Vice President – Exploration, Northern Division

Lynn Boone Henry
Vice President – Reservoir Engineering

Kurt M. Reinecke
Vice President – Exploration, Southern Division

Wilfred R. Roux
Vice President – Geophysics

Huntington T. Walker
Vice President – Land

Duane J. Zavadil
Vice President – Government and Regulatory Affairs

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark one)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2004

or

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ______________ to ________________________________

Commission File No. 001-32367

BILL BARRETT CORPORATION
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation)	**80-0000545** (IRS Employer Identification No.)
1099 18th Street, Suite 2300 **Denver, Colorado** (Address of principal executive offices)	**80202** (Zip Code)

(303) 293-9100
(Registrant's telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common Stock, $.001 par value	New York Stock Exchange
Series A Junior Participating Preferred Stock Purchase Rights	New York Stock Exchange

Securities registered pursuant to section 12(g) of the Act: None

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

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). [ ] Yes [X] No

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of March 1, 2005. $602,471,545*

*Without assuming that any of the issuer's directors or executive officers, or the entities that own 10,081,278, 6,415,356, or 4,582,400 shares of common stock, respectively, is an affiliate, the shares of which they are beneficial owners have been deemed to be owned by affiliates solely for this calculation.

As of March 1, 2005, the registrant had outstanding 43,362,738 shares of $.001 par value common stock.

DOCUMENTS INCORPORATED BY REFERENCE

List hereunder the following documents if incorporated by reference and the Part of the Form 10-K (e.g., Part I, Part II, etc.) into which the document is incorporated: (1) Any annual report to security holders; (2) Any proxy or information statement; and (3) Any prospectus filed pursuant to Rule 424(b) or (c) under the Securities Act of 1933. The listed documents should be clearly described for identification purposes (e.g., annual report to security holders for fiscal year ended December 24, 1980).

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control, which may include statements about our:

- business strategy;
- identified drilling locations;
- exploration and development drilling prospects, inventories, projects and programs;
- natural gas and oil reserves;
- ability to obtain permits and governmental approvals;
- technology;
- financial strategy;
- realized oil and natural gas prices;
- production;
- lease operating expenses, general and administrative costs and finding and development costs;
- future operating results; and
- plans, objectives, expectations and intentions.

All of these types of statements, other than statements of historical fact included in this Annual Report on Form 10-K, are forward-looking statements. These forward-looking statements may be found in "Items 1 and 2. Business and Properties", "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations", including the "Risk Factors" subsection, and other sections of this Annual Report on Form 10-K. In some cases, you can identify forward-looking statements by terminology such as "may", "will", "could", "should", "expect", "plan", "project", "intend", "anticipate", "believe", "estimate", "predict", "potential", "pursue", "target" or "continue", the negative of such terms or other comparable terminology.

The forward-looking statements contained in this Annual Report on Form 10-K are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management's assumptions about future events may prove to be inaccurate. Management cautions all readers that the forward-looking statements contained in this Annual Report on Form 10-K 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 "Management's Discussion and Analysis of Financial Condition and Results of Operations — Risk Factors" section and elsewhere in this Annual Report on Form 10-K. All forward-looking statements speak only as of the date of this Annual Report on Form 10-K. 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.

PART I

Items 1 and 2. Business and Properties

BUSINESS

General

Bill Barrett Corporation (the "Company", "we" or "us") was formed in January 2002 and is incorporated in the State of Delaware. We explore for and develop oil and natural gas in the Rocky Mountain region of the United States. We have exploration and development projects in nine basins. Our management has an extensive track record with expertise in the full spectrum of Rocky Mountain plays. Our strategy is to maximize stockholder value by leveraging our management team's experience finding and developing oil and gas in the Rocky Mountain region to profitably grow our reserves and production, primarily through the drill-bit.

The following table provides information regarding our operations by basin.

Basin	At December 31, 2004					
	Estimated Net Proved Reserves (1) (Bcfe)	Net Producing Wells	Net Undeveloped Acreage	Pretax PV-10 (1) (in millions)	Standardized Measure (2) (in millions)	December 2004 Average Daily Net Production (MMcfe/d)
Piceance	88.7	86	10,031	$ 141	$ 94	6.0
Wind River	82.8	134	165,946	208	180	41.1
Uinta	49.3	19	96,672(3)	81	64	16.9
Powder River	40.4	282	59,587	96	83	21.0
Williston	31.0	31	113,403	66	45	6.3
Green River	—	—	7,977(4)	—	—	—
Denver-Julesburg	—	—	346,022(5)	—	—	—
Paradox	—	—	10,004	—	—	—
Big Horn	0.1	1	145,442	—	—	—
Other	—	—	16,002	—	—	—
Total	292.3	553	971,086(3)(4)(5)	$ 592	$ 466	91.3

(1) Our reserves and the present value of future net revenues before income taxes were determined using the market prices for natural gas and oil at December 31, 2004, which were $5.52 per MMBtu of natural gas and $43.46 per barrel of oil, without giving effect to hedging transactions. Our PV-10 would have been $588 million after giving effect to hedging transactions. Our reserve estimates are based on a reserve report prepared by us and reviewed by our independent petroleum engineers. See "Business — Properties — Proved Reserves".

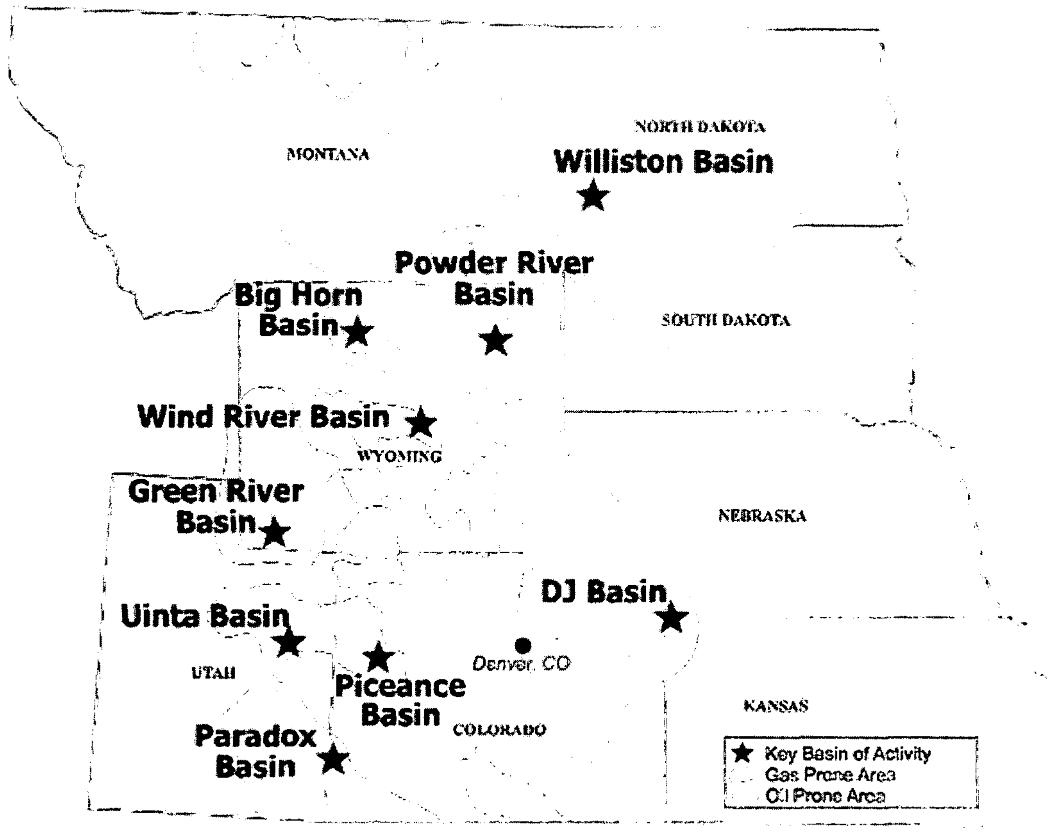
(2) The Standardized Measure represents the present value of estimated future cash inflows from proved natural gas and oil reserves, less future development, production, and income tax expenses, discounted at 10% per annum to reflect timing of future cash flows and using the same pricing assumptions as were used to calculate PV-10. Standardized Measure differs from PV-10 because Standardized Measure includes the effect of future income taxes.

(3) An additional 161,750 net undeveloped acres that are subject to drill-to-earn agreements are not included.

(4) Subsequent to December 31, 2004, we offered our working interest partner the opportunity to purchase a 60% interest in three leases covering 4,518 gross net acres.

(5) Subsequent to December 31, 2004, we entered into a joint exploration agreement with respect to our Tri-State prospect and sold our industry partner a 50% interest in that prospect. As of March 1, 2005, we hold 173,011 net undeveloped leasehold acres in that project area. See "—Denver-Julesburg Basin" below.

Key Basins of Activity



We operate in nine basins, the Piceance, the Wind River, the Uinta, the Powder River, the Williston, the Green River, the Denver-Julesburg, the Paradox and the Big Horn.

Piceance Basin. The Piceance Basin is located in northwestern Colorado and represents a new focus area for our development activities and expected production growth in 2005. We acquired developed and undeveloped properties in September 2004.

Wind River Basin. The Wind River Basin is located in central Wyoming and, for the year ended December 31, 2004, was our largest producing area. Our operations in the basin include active infill and field expansion development programs, as well as eight exploration projects that make this basin an important exploratory area. Our development operations are conducted in three general project areas.

Uinta Basin. The Uinta Basin is located in northeastern Utah and represents a substantial part of our development and exploration activities and expected production growth in 2005. Our development operations are conducted primarily in two areas. We also have a position in four exploratory projects in the basin.

Powder River Basin. The Powder River Basin is located in northeastern Wyoming. Substantially all of our operations in this basin are in coalbed methane plays targeting the Wyodak and Big George coals. Our coalbed methane activities have resulted in high drilling success and lower drilling costs than our other drilling programs; however, the average coalbed methane well in the Powder River Basin produces at a much lower rate with fewer reserves attributed to it than conventional natural gas wells in the Rockies. Our development operations are conducted in seven project areas in the basin. Many of our leases in the Wyodak coalbed methane area in this basin are in areas that have been partially depleted or drained by earlier offset drilling.

Williston Basin. The Williston Basin is located in western North Dakota, northwestern South Dakota and eastern Montana. It is a predominantly oil prone basin and represents our only oil focused project area. Our activities in this basin include development and exploration drilling programs concentrated in two areas. We use horizontal drilling technology and 3-D seismic surveys in the Williston to expand existing fields, target exploration projects and increase our recoveries.

Green River Basin. The Green River Basin is located in southwestern Wyoming and adjacent areas of northeastern Utah. In

2004, we acquired leasehold interests in an exploration project in the basin and our industry partner commenced drilling an exploration well in February 2005.

Denver-Julesburg Basin. Our operations in the DJ Basin are concentrated in the Tri-State exploration project, which extends into Colorado, Kansas and Nebraska. These operations are exploratory and involve the extensive use of 3-D seismic technology to target shallow biogenic gas and deeper conventional oil accumulations.

Paradox Basin. The Paradox Basin is located in southwestern Colorado and southeastern Utah. We are in the initial stages of two exploration projects in the basin focusing on natural gas.

Big Horn Basin. The Big Horn Basin is located in north central Wyoming. We are in the initial phases of an exploration project targeting both structural-stratigraphic and basin-centered tight gas plays.

Our Strategy

The principal elements of our strategy to maximize stockholder value are to:

- ***Drive Growth Through the Drill-bit.*** We expect to generate long-term reserve and production growth predominantly through our drilling activities. We believe our management team's experience and expertise enable us to identify, evaluate and develop new natural gas and oil reservoirs. Throughout our operations, we apply technology, including advanced drilling and completion techniques and new geologic and seismic applications. From inception through December 31, 2004, we participated in the drilling of 474 gross wells. We plan to participate in the drilling of a total of 369 gross wells in 2005.

- ***Pursue High Potential Projects.*** We have assembled several projects that we believe provide future long-term drilling inventories. In addition to nine key development areas, as of March 1, 2005 we are involved in 24 exploration projects. Our team of 17 geologists and geophysicists, which includes our Chief Executive Officer, is dedicated to generating new geologic concepts. These individuals have an average of more than 23 years of experience in the industry, primarily in the Rocky Mountain region. Our long-term objective is to allocate between 70% and 80% of our capital budget to development projects, with the balance allocated to higher risk, higher potential exploration projects.

- ***Focus on Natural Gas in the Rocky Mountain Region.*** We intend to capitalize on the large estimated undeveloped natural gas resource base in the Rocky Mountains, while selectively pursuing attractive oil opportunities in the region. We believe the Rockies represent one of the few natural gas provinces in North America with significant remaining development potential. All of our production is from the Rockies, and for the month of December 2004, approximately 92% was natural gas.

- ***Reduce Costs and Maximize Operational Control.*** Our objective is to generate profitable growth and high returns for our stockholders. We expect that our unit cost structure will benefit from economies of scale as we grow, maintaining high operatorship of our reserves and production, and our continuing cost management initiatives. As we manage our growth, we are actively focusing on managing lease operating expenses, general and administrative costs and finding and development costs. It is strategically important to us to serve as operator of our properties when possible, as that allows us to exert greater control over costs and timing in our exploration, development and production activities. We operated approximately 87% of our December 2004 production and, as of December 31, 2004, we owned an average working interest of approximately 67% in 1,451,516 gross undeveloped acres, as well as an additional 161,750 net undeveloped acres that are subject to drill-to-earn agreements. Subsequent to December 31, 2004, we entered into a joint exploration agreement and sold our industry partner a 50% interest in approximately 346,000 net undeveloped leasehold acres in the Tri-State prospect area.

- ***Pursue Reserve and Leasehold Acquisitions.*** Past acquisitions have played an important part in establishing our asset base. We intend to use our experience and regional expertise to supplement our drill-bit growth strategy with complementary acquisitions that have the potential to provide long-term drilling inventories or that have undeveloped leasehold positions. We actively review acquisition opportunities on an ongoing basis.

Competitive Strengths

We have a number of strengths that we believe will help us successfully execute our strategy.

- ***Experienced Management Team.*** Although we compete against companies with more financial and human resources than ours, we believe our management team's experience and expertise in the Rocky Mountains provide a distinct competitive advantage. Our 13 corporate officers average 26 years of experience working in and servicing the industry. Our Chief Executive Officer and other members of our management team worked together as executives or advisors for many years with Barrett Resources Corporation, a publicly-traded Rocky Mountain oil and gas company that was founded in 1980 and sold in 2001 in a transaction valued at approximately $2.8 billion. Further, members of our team are widely acknowledged as leading explorationists and were involved in finding or developing several of the largest Rocky Mountain natural gas and oil fields during the last three decades, including the Grand Valley, Parachute, and Rulison fields in the Piceance Basin, the Powder River Basin coalbed methane play, the Hilight field, the Cave Gulch field and the Madden field.

- ***Inventory of Growth Opportunities.*** We have established an asset base of 971,086 net undeveloped leasehold acres as of December 31, 2004, as well as an additional 161,750 net undeveloped acres that are subject to drill-to-earn agreements. From inception through December 31, 2004, we participated in the drilling of 474 gross wells. In 2005, we plan to participate in the drilling of 369 gross wells across our operations. In addition, as of March 1, 2005, we have 24 exploration projects.

- ***Rocky Mountain Asset Base.*** In January 2004, the Department of Energy estimated that Rocky Mountain natural gas production would grow by 91% from 2002 to 2025, compared to other large U.S. gas producing areas, which were forecast to decline or grow at significantly lower rates over the same period. Our assets are focused in the natural gas prone basins of the Rockies. This asset base allows us to leverage our experience and expertise as we pursue our growth strategy. Although we are focused in the Rockies, we are active in nine distinct basins in the region, which provide both geographic and geologic diversification.

- ***Financial Flexibility.*** As of December 31, 2004, we had $100 million in cash with no debt outstanding and $200 million available under our revolving credit facility. We are committed to maintaining a conservative financial position to preserve our financial flexibility. Based on our current budget, we believe that our operating cash flow and available borrowing capacity under our credit facility provide us with the financial flexibility to pursue our planned exploration and development activities and leasehold acquisitions in 2005.

- ***Significant Employee Investment.*** All of our corporate officers and employees own our stock or stock options. As a result, our management team and other employees have interests that are aligned with those of our stockholders.

Risks Related to Our Business and Strategy

The following considerations could have a negative effect on our strategy as well as activities on our properties and what we believe to be our competitive strengths to execute our strategy and activities:

- ***Limited Operating History.*** We are a relatively new company. As such, we have made major expenditures to acquire and develop our property base and substantially increase production. This resulted in significant losses in certain periods since our inception. We can give no assurance that we will not incur losses in the future.

- ***Risks Relating to Oil and Gas Reserves.*** Reserve estimates are based on many assumptions and our properties may not produce as we originally forecast. For example, we reduced our reserves by approximately 32 Bcfe in 2004 as a result of infill drilling in depleted sands in the Wind River Basin and greater pressure depletion than expected in two areas in the Wyodak coals in the Power River Basin. In addition, our reserve report reflects that, as we produce our proved reserves, they would decline at an estimated rate of 7.2% per year after 2005, which will only be abated if we are successful in finding or acquiring new reserves.

- ***Concentration and Competition.*** Our concentration in the Rocky Mountains may make us disproportionately exposed to impacts of weather, government regulation and transportation constraints common to that geographic location. Competition with other companies in the Rockies is significant and may hinder our ability to pursue reserve and leasehold acquisitions as well as our ability to operate in certain of our core areas.

- ***Risks Related to Rapid Growth.*** We have grown rapidly through acquisitions and may engage in additional acquisitions in the future. Acquired properties may not produce as projected and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against them.

For a discussion of other considerations that could have a negative effect on our strategy and what we believe to be our competitive strengths to execute our strategy, see "Management's Discussion and Analysis of Financial Condition and Results of Operation—Risk Factors" and "—Cautionary Note Regarding Forward-Looking Statements".

Summary of Development Areas

The following table summarizes the information regarding our key development areas as of December 31, 2004 that is discussed in more detail below:

Development Area	Basin	Average Working Interest (1)	2005 Drilling Locations (2)	2005 Development Area Budget (3) (in millions)
Gibson Gulch	Piceance	71.5%	95	$ 120
Cave Gulch	Wind River	89.2	10	18
Cooper Reservoir	Wind River	98.5	9	16
Wallace Creek/Stone Cabin	Wind River	99.5	—	3
Hill Creek	Uinta	72.2	—	—
West Tavaputs	Uinta	100.0	17	52
Powder River	Powder River	79.3	218	20
Williston	Williston	39.7(4)	6	9
Total			355	$ 238

(1) Average working interest is based on December 2004 production, including operated and non-operated properties.

(2) For each development area, 2005 drilling locations represent total gross locations specifically identified and scheduled by management as of December 31, 2004 as an estimate of our 2005 drilling activities on existing acreage. Of the 2005 drilling locations, 66 are classified as PUDs. Through February 28, 2005, we had commenced drilling of 32 of the 2005 drilling locations shown in the table, including 10 PUD locations. Our actual drilling activities may change depending on the availability of capital, regulatory approvals, seasonal conditions, natural gas and oil prices, costs, drilling results and other factors. For a more complete description of our proposed activities, see "Business".

(3) Includes budgeted drilling expenditures as well as exploration and facilities costs for the area and excludes property acquisition costs and exploration costs for other areas. Figures for 2005 are our current estimates.

(4) We operated 75% of our December 2004 production in the Williston Basin, with an average working interest of 92% per operated well. Our average working interest in our non-operated wells is 13%.

Joint Exploration Strategy and Summary of Exploration Projects

Joint Exploration Strategy

We are seeking industry partners to enter into joint exploration agreements, which will involve the sale of portions of our interests in several of our exploration projects to industry partners, and joint drilling obligations for these projects. The primary objective of this effort is to increase our exposure to potential reserves and production, while recouping a portion of our initial investment through the sale of a portion of our interests. In connection with these anticipated joint exploration agreements, we expect to sell approximately 30% to 60% of our working interests, depending on the project. We plan to use the proceeds from these arrangements to increase exploration activities beyond those contemplated in our current capital expenditure budget.

Summary of Exploration Projects

The following table summarizes our exploration projects that are discussed in more detail below.

Exploration Project	Basin	Project Net Acreage (1)	Average Working Interest Before Selldowns (2)	2005 Estimated Exploratory Activities (3)
Gibson Gulch (4)	Piceance	17,187	78%	Drill two wells
Cave Gulch/Waltman (4)(5)	Wind River	14,051	77%	Drill one deep well commitment; drill second deep well subject to entering into joint exploration agreement
Cooper Reservoir (4)(5)	Wind River	12,435	78%	Drill one well; drill one deep well subject to selldown efforts
East Madden	Wind River	22,266	57%	Complete one deep well
Pommard	Wind River	2,200	100%	One completion and drill one deep well subject to entering into joint exploration agreement
Stone Cabin (4)(5)	Wind River	12,342	82%	Drill one deep well subject to entering into joint exploration agreement
Talon	Wind River	70,973	32%	Drill six wells
Wallace Creek (4)(5)	Wind River	21,892	85%	Participate in five wells subject to entering into joint exploration agreement
Windjammer(5)	Wind River	8,844	35%	3-D seismic program; drill two wells subject to entering into joint exploration agreement
Garmesa	Uinta	8,217	42%	3-D seismic, drill three wells
Lake Canyon/Brundage Canyon	Uinta	33,470(6)	60%	3-D seismic, drill three wells
West Tavaputs Deep(5)	Uinta	43,171	92%	Drill one well; drill second well contingent on results of first well
Hook	Uinta	11,353	99%	Acreage acquisition
Wyodak/Big George	Powder River	62,889	65%	Four pilot programs
Grand River	Williston	17,356	75%	Participate in two wells subject to entering into joint exploration agreement
Red Bank(5)	Williston	39,081	67%	Participate in two wells subject to selling down interests
Indian Hills (4)(5)	Williston	4,038	71%	Participate in one well; participate in an additional well subject to entering into joint exploration agreement
Red Water(5)	Williston	10,981	75%	Participate in one well subject to entering into joint exploration agreement
Mondak(5)	Williston	7,651	41%	Participate in three wells
Antelope Hollow	Green River	7,977(7)	60%(7)	Drill one well
Tri-State	DJ	346,022(8)	94%(8)	2-D and 3-D seismic program, drill two wells
Pine Ridge	Paradox	1,960	96%	3-D seismic, acreage acquisition
Yellow Jacket	Paradox	8,044	61%	Acreage acquisition
Big Horn	Big Horn	147,122	75%	Acreage acquisition

---

(1) Project net acreage is the amount of our net leasehold acreage at December 31, 2004 that we have associated with each of our exploration projects.

(2) Average working interest is based on leasehold acreage at December 31, 2004. Also, the working interest numbers are subject to further selling of working interests to industry partners in connection with our plans to seek industry partners to enter into joint exploration agreements with joint drilling obligations. We anticipate selling 30% to 60% of our working interest on several of our exploration projects.

(3) Of the exploration activities planned for 2005 that are included in this table, some have already occurred. With respect to those

that have not occurred, our actual activities may change depending on regulatory approvals, seasonal conditions and other factors, including our ability to enter into joint exploration agreements with joint drilling obligations with industry partners. For a description of activities through March 1, 2005, including determination of production capability as commercially successful or unsuccessful, see the description of each project in the Basin sections under "Business".

(4) Represents an exploration project that extends an existing development project.

(5) *Currently not included in our 2005 capital expenditure budget. These activities are contingent upon obtaining an industry partner pursuant to a joint exploration agreement for the prospect or revising our capital expenditure budget.*

(6) Does not include an additional 161,750 net undeveloped acres that are subject to drill-to-earn agreements.

(7) Subsequent to December 31, 2004, we offered our working interest partner the opportunity to purchase a 60% interest in three leases covering 4,518 gross and net acres.

(8) *Subsequent to December 31, 2004, we entered into a joint exploration agreement with respect to our Tri-State prospect and sold our industry partner a 50% interest in this prospect.*

Piceance Basin

The Piceance Basin is located in northwestern Colorado. We entered the Piceance Basin on September 1, 2004, when we purchased producing and undeveloped properties from Calpine Corporation and Calpine Natural Gas L.P., which included 25,985 gross and 19,180 net acres in and around Gibson Gulch field, for approximately $137 million.

Our total leasehold position in the Piceance Basin as of December 31, 2004 consisted of 12,812 gross and 10,031 net undeveloped acres and 9,289 gross and 7,156 net developed acres, all of which is in our Gibson Gulch area. Our estimated net proved reserves in the Piceance Basin at year end 2004 were 88.7 Bcfe. Our planned activities will be in the southeastern portion of this basin. Several members of our senior management team were involved with the discovery, exploration and development of three large gas fields, Grand Valley, Parachute and Rulison, located in the south central part of the Piceance Basin. These fields lie along a continuous 30 mile productive trend of basin-centered gas trapped in the tight sandstones of the Mesaverde Group. Industry participants along this trend, which in addition to Grand Valley, Parachute and Rulison include Mamm Creek and our Gibson Gulch field, have been actively conducting development drilling programs on 10- and 20-acre patterns. We received authority for development on a 10-acre pattern and are evaluating development on this basis. Our natural gas production in this basin currently is gathered through our own gathering system and delivered to markets through pipelines owned by Questar Pipeline Company.

Gibson Gulch

The Gibson Gulch area is a basin-centered gas play along the north side of the Divide Creek anticline at the eastern end of the Piceance Basin's productive Mesaverde trend. Our properties are largely undeveloped relative to those fields to the west and southwest. Currently, our primary focus at Gibson Gulch is a Mesaverde development drilling program with well depths between 7,000 and 8,000 feet. In our initial wells, we plan to drill to 8,500 feet to test the potential of the deeper more continuous Cozzette and Corcoran sandstones, which are productive at the nearby Divide Creek field. We also plan to test the potential of completing the shallower Wasatch formation in selected wellbores.

Our estimated net proved reserves in this basin were 88.7 Bcfe at December 31, 2004. At December 31, 2004, we held interests in 93 gross producing wells that produced 6.0 MMcfe/d net to our interest in the month of December 2004 with an average working interest of 72%. At December 31, 2004, our total leasehold position in Gibson Gulch consisted of 12,812 gross and 10,031 net undeveloped acres and 9,289 gross and 7,156 net developed acres. Initially, our drilling program is focused on the undeveloped acreage comprised of fee leaseholds, which should provide broader drilling windows and fewer regulatory challenges than typically encountered with a federal leasehold. We believe that additional locations may be present on our acreage position as we investigate the feasibility of 10-acre well density for which we have received approval. Currently, we estimate our capital expenditures for 2005 will be $120 million to participate in the drilling of 95 wells and the recompletion of 12 wells in the Gibson Gulch area. In the period from when we acquired these properties on September 1, 2004 through December 31, 2004, our capital expenditures in this area were $151.8 million and included our acquisition of the properties as well as participating in drilling six wells and three recompletions.

Wind River Basin

The Wind River Basin is located in central Wyoming. Our activities in the area are concentrated primarily in the eastern Wind River Basin. Our Wind River Basin development operations are conducted in three general project areas located along the greater

Waltman Arch area: Cave Gulch, Cooper Reservoir and Wallace Creek. In addition, we have eight exploration projects, of which Pommard, Windjammer and East Madden are in areas of the basin where we have no existing development operations. We are attempting to sell down a portion of our interests in the Wind River Basin to industry partners.

Our total leasehold position in the Wind River Basin as of December 31, 2004 consisted of 388,172 gross and 165,946 net undeveloped acres and 7,251 gross and 5,936 developed acres. Our estimated net proved reserves in the Wind River Basin at year end 2004 were 82.8 Bcfe. Our current operations in the basin include active infill and field expansion development programs, as well as exploration activities. We have access to over 450 square miles of 3-D seismic in seven different surveys covering the Cave Gulch, Cooper Reservoir, Wallace Creek, Stone Cabin and East Madden project areas, and 3,700 miles of 2-D seismic across a majority of the eastern Wind River Basin. Our natural gas production in this basin is gathered through our own gathering systems and delivered to markets through pipelines owned by Kinder Morgan Interstate and Colorado Interstate Gas Company ("CIG").

Cave Gulch

The Cave Gulch field is a structural-stratigraphic play along the Owl Creek Thrust at the northern end of the Waltman Arch. Our primary focus is a 20-acre development program involving drilling and recompletions in discontinuous lenticular sands at depths from approximately 4,900 to 9,200 feet in the Lance formation. We also are producing from wells in two other zones: the Fort Union, from 3,500 to 4,900 feet, and the overpressured deep Frontier and Muddy formations, from 16,700 to 19,000 feet.

Our estimated net proved reserves in the Cave Gulch field were 46.7 Bcfe at year end 2004. Also at December 31, 2004, we had interests in 72 gross producing wells, and net production for the month of December 2004 was 22.3 MMcfe/d with an average working interest of 89%. We operated 99% of our December 2004 production in the area. At December 31, 2004, our total leasehold position in Cave Gulch consisted of 16,292 gross and 12,402 net undeveloped acres and 2,011 gross and 1,649 net developed acres. Currently, we estimate our capital expenditures for 2005 will be $18 million in Cave Gulch, which includes nine gross Lance wells and one recompletion. In 2004, our capital program in this area was approximately $17 million and included successfully drilling and completing ten Lance wells. In the third quarter of 2004, we identified one extension well as a dry hole.

Cooper Reservoir

Our position in the Cooper Reservoir field lies six miles south of Cave Gulch along the Waltman Arch. As at Cave Gulch, our targets at Cooper are the Lance and Fort Union formations at depths ranging from 3,200 to 8,500 feet. Currently, our primary focus is 20-acre development of the Lance and Fort Union formations within the Cooper Reservoir unit, and 40-acre Lance development on field extensions north and south of this unit. We are using 3-D seismic technology across the Cooper Reservoir area region to evaluate other opportunities.

Our estimated net proved reserves in Cooper Reservoir were 22.7 Bcfe at year end 2004. Also at December 31, 2004, we had interests in 72 gross producing wells, and net production for the month of December 2004 was 12.3 MMcfe/d with an average working interest of 98.5%. We operated all of our December 2004 production in the area. At December 31, 2004, our total leasehold position in Cooper Reservoir consisted of 12,992 gross and 9,676 net undeveloped acres and 2,882 gross and 2,759 net developed acres. Currently, we estimate our capital expenditures for 2005 will be $16 million in Cooper Reservoir, which includes nine gross Lance/Fort Union wells, one Lance/Fort Union recompletion, and gas gathering and water disposal facilities. In 2004, we drilled 29 Lance/Fort Union wells as part of our 2004 capital program of $36 million. 19 of those wells are producing, and two extension wells were classified as dry holes.

Wallace Creek, Stone Cabin and Pommard

Our estimated net proved reserves in Wallace Creek, Stone Cabin and Pommard were 13.3 Bcfe at year end 2004. At December 31, 2004, we had a 100% working interest in 15 producing wells and net production for the month of December 2004 was 6.2 MMcfe/d, all of which we operated. Currently, we estimate our capital expenditures for 2005 will be $2.6 million. In 2004, our capital program in this area was approximately $28.5 million and included eight wells.

In 2004, four Raderville wells were drilled with no commercial production from that formation. One of these wells, the Stone Cabin 44-16, was recompleted and, as of March 1, 2005, was producing from the Lewis formation, and the other three wells, the Stone Cabin 11-27R, Stone Cabin 33-21R and Stone Cabin 33-16R, were determined to be dry holes. Through December 2004, three additional Stone Cabin wells, consisting of one development and two exploratory wells, were drilled and determined to be dry holes. In September 2004, we finished drilling and ran production casing at a depth of 14,976 feet on the Pommard #1. We are continuing to test the Tensleep formation, but, based on results to date, the well was determined to be a dry hole with total estimated costs of $9.0 million, including $7.9 million through December 31, 2004. We also may evaluate several other uphole formations.

Our total leasehold position in Wallace Creek, Stone Cabin and Pommard consists of 38,999 gross and 32,844 net undeveloped acres and 1,758 gross and 1,389 net developed acres, with an average working interest of 84% at December 31, 2004.

We also recognize a potential coalbed methane play in the Wallace Creek area. We currently are assessing the multiple coal beds of the Meeteetse formation which underlies the Lance formation in a 1,500 to 4,500 feet depth range.

Windjammer

Our Windjammer exploratory area lies to the northwest of our Wallace Creek development project. We are evaluating the same Raderville formation in Windjammer that we currently are developing at Wallace Creek. Based on 3-D amplitude mapping, subsurface and well control data, we believe the Raderville trend extends from Wallace Creek to the northwest into the Windjammer area. In late 2004, we conducted a 114 square mile 3-D survey across the Windjammer area and are currently processing this survey. We held 8,745 net undeveloped leasehold acres for exploration in this area as of December 31, 2004.

Talon and East Madden

In our Talon and East Madden areas, we are targeting an unconventional, basin-centered play concept in the Lance and Fort Union formations. Currently, we estimate our capital expenditures for 2005 will be $15 million to purchase leases, acquire 3-D seismic, drill one Lance exploratory well, and drill five shallow Fort Union wells. In 2004, our capital program in this area was approximately $15 million and included five Fort Union wells, one East Madden and three recompletions. We have assembled 262,061 gross and 93,240 net leasehold acres in the Talon and East Madden areas as of December 31, 2004.

Talon. The Talon exploratory project lies due west of the Cave Gulch area and extends over a multi-township area. We are targeting a basin-centered Lance and Fort Union play in the project. To date, five Lance wells and three Fort Union wells have been drilled and three Fort Union recompletions have been performed. As of March 11, 2005, all six wells were producing down the sales line, four were being tested and one recompletion was temporarily abandoned. We have begun building infrastructure to accommodate a development program. Our first production was in May 2004 and, in December 2004, we produced a net 0.1 MMcfe/d with an average working interest of 56%.

At December 31, 2004, the first well drilled in the Talon area was producing but had evaluated costs that exceeded its estimated fair value, resulting in an impairment expense of $0.5 million for 2004. Prior to year end 2004, this well was completed in the Lance formation and connected to the sales line. Subsequent to year end 2004, this well was completed in a zone further uphole in the Fort Union and connected to the sales line. We believe there are additional zones in the Fort Union that we may complete at a later date.

East Madden. Our East Madden exploration prospect lies east of the extensive Madden field along the Madden anticline. Our concept for East Madden, similar to that in the Talon region, is to explore the overpressured Lance formation. The Lance formation ranges from approximately 11,000 to 16,500 feet in depth in this area. As of March 11, 2005, we had reached total depth and were waiting on completion on our 16,600 foot Lance test well, for which we are operator for an industry partner pursuant to a farm-out agreement. We will retain a 25% working interest before payout and a 45% working interest after payout in this well. If the industry partner elects to drill a second option well, we will farmout an additional one-sixth (16.67%) interest, so that our eventual interest in the prospect will be 37.5%. If the industry partner drilled both the test well and option well, it will have earned 10,207 net acres out of our total net acreage inventory of 22,266. Depending on our exploratory results in the East Madden play, we may identify locations in the Lance formation to develop across portions of our acreage on an 80-acre pattern.

Uinta Basin

We have a substantial acreage position in the Uinta Basin, including 134,036 gross and 96,672 net undeveloped and 6,118 gross and 5,811 net developed leasehold acres at December 31, 2004. Our estimated net proved reserves in the Uinta Basin were 49.3 Bcfe at year end 2004. Our exploration and development activities are focused on two geologic play types (structural-stratigraphic and basin-centered gas) in several locations.

West Tavaputs

We began operations in the Uinta Basin in April 2002 at the northwestern end of the Garmesa Trend through the acquisition of 3.4 Bcfe of proved reserves and 46,702 gross and 42,355 net leasehold acres at West Tavaputs. We have a 100% working interest in the majority of this field. Although the field was discovered in 1952, there had been only limited activity at West Tavaputs over the last 20 years. In particular, no modern completion techniques or 3-D seismic technology had been applied to this field. Since we began operations here in 2002, we have drilled 17 wells, eight of which are producing, seven are awaiting completion, and one of which is awaiting further testing. With effective application of new fracturing techniques and new geologic interpretations, we have greatly enhanced our ability to commercialize the gas potential of this area. As of March 1, 2005, we were seeing increased production from the Wasatch and the deeper Mesaverde formations.

Our estimated net proved reserves in West Tavaputs were 40.3 Bcfe at year end 2004. As of December 31, 2004, we had interests in a total of 20 wells in this area that were capable of production. Because of limitations in infrastructure, five of those wells were shut-in. The remaining 15 wells, in which we had a 100% working interest, produced 7.7 net MMcfe/d in December 2004. We operated all of our December 2004 production in West Tavaputs. We plan additional infrastructure improvements in 2005 to relieve the constraint issues. Our natural gas production at West Tavaputs is gathered and compressed by our facilities and delivered to markets on the Questar pipeline system.

Our total leasehold position in West Tavaputs consists of 41,560 gross and 37,853 net undeveloped acres and 5,318 gross and net developed acres as of December 31, 2004. Full development of the West Tavaputs area is anticipated to require the completion of an EIS, which will be initiated as soon as appropriate. Currently, we estimate our capital expenditures in 2005 will be $52 million in the West Tavaputs area to fund our interests in 17 additional gross Wasatch-Mesaverde wells to depths ranging between 7,500 to 9,200 feet, four recompletions, and gathering and compression facilities. We recently completed an 83 square mile 3-D seismic survey covering the field area where existing but limited 2-D seismic coverage is inadequate to image the subsurface. On November 10, 2004, the BLM's winter stipulations, which limit our activities, went into effect. As a result, we were not able to complete four of the eight wells drilled in 2004. We will commence completion operations on these four wells in the spring of 2005 when restrictions are lifted.

Garmesa

The Garmesa prospect lies southeast of West Tavaputs and consists of three adjacent prospects areas: Hill Creek, Tumbleweed and Cedar Camp. We believe these prospects have similar geologic characteristics and reserve potential, but are differentiated mainly by our level of working interest, industry partners and ownership structures. Currently, we estimate capital expenditures for 2005 will be $3.7 million in Garmesa to conduct a 3-D seismic survey, drill three wells, and further develop related infrastructure. In 2004, our capital program in this area was approximately $10.7 million and included two wells, infrastructure expenses, the acquisition of a 16 square mile 3-D seismic survey and regulatory expenditures

Hill Creek. Within the Hill Creek area, we target the Dakota, Entrada and Wingate formations at depths down to 11,900 feet. In 2004, we drilled the tenth well in this area, which was the final well required under our exploration agreement with an industry partner.

Our estimated net proved reserves at Hill Creek were 9.1 Bcfe at year end 2004. Our ten gross producing wells in the area produced 9.2 MMcfe/d net to our interest in December 2004, with an average net revenue interest of 72%. Our natural gas production in Hill Creek is sold at the wellhead. Our total leasehold position in Hill Creek consists of 1,508 gross and 754 net undeveloped acres and 800 gross and 493 net developed acres.

Pursuant to an exploration agreement with an industry partner, we earned a net revenue interest in the 10 wells drilled in the Hill Creek area and the drillsite spacing unit pertaining to each well. We have the right to participate for a 50% working interest in the next nine wells proposed in the Hill Creek area by our industry partner.

Tumbleweed. Our Tumbleweed project area is located directly southeast along the Garmesa Trend and adjacent to Hill Creek. As of December 31, 2004, we held a leasehold position of 7,833 gross and 2,877 net undeveloped acres, with an average working interest of 37%. We operate this prospect and are targeting the same reservoir objectives as the Hill Creek project. In order to fulfill our federal unit obligations and preserve our acreage position, we and our partners drilled a 5,785 foot exploration well in June 2003. The well was a dry hole and was too shallow to evaluate the reservoirs that are productive in the Hill Creek area. We commissioned a 21-square mile 3-D seismic survey in 2005 in order to evaluate the potential to develop this area. We are planning an 11,000-foot test well for the third quarter of 2005.

Cedar Camp. Our Cedar Camp project area is located directly southeast along the Garmesa Trend from the Tumbleweed area. As of December 31, 2004, we held a leasehold position of 9,197 gross and 4,093 net undeveloped acres, with an average working interest of 45%. We operate this prospect and are targeting the same reservoir objectives as the Hill Creek and Tumbleweed projects. In 2004, we commissioned a 16-square mile 3-D seismic survey in order to evaluate the potential to develop this area. The survey was completed in November 2004 and, as of March 11, 2005, was still being interpreted. We are planning two 10,500-foot test wells beginning in the first half of 2005.

Lake Canyon/Brundage Canyon

Lake Canyon. Lake Canyon is an exploration project that targets basin-centered tight gas in the Mesaverde formation at depths ranging from approximately 10,000 to 14,000 feet. We believe Lake Canyon has a structural position similar to the Natural Buttes field in which other operators have been developing Mesaverde and Wasatch reservoirs. As of December 31, 2004, we had assembled over 33,470 net acres in this play. Currently, we estimate our capital expenditures for 2005 will be $10.1 million for acreage acquisition and to drill three exploratory wells. In 2004, our capital program in this area was approximately $2.9 million and included lease bonus payments and costs associated with the drilling of the initial well at Brundage Canyon.

In July 2004, we and an industry partner entered into an exploration and development agreement with the Ute Indian Tribe of the Uintah and Ouray Reservation, or the Ute Tribe, to explore for and develop oil and natural gas on approximately 125,000 of their net undeveloped acres that are located in Duchesne and Wasatch Counties, Utah. This drill-to-earn agreement was revised in September 2004 to include the Ute Development Corporation as a party and was approved by the Department of Interior's Bureau of Indian Affairs, or BIA, in October 2004. Pursuant to this agreement, we have the right to earn up to a 75% working interest in the Mesaverde formation and deeper horizons, plus up to a 25% interest in shallower formations. To earn these interests pursuant to this agreement, we and our partner are required to drill 13 deep wells and 21 shallow wells prior to December 31, 2009, including one deep and two shallow wells by December 31, 2005. The Ute Tribe has an option to participate for a 25% working interest in wells drilled pursuant to the agreement. This right terminates as to all future wells in a lease block if the Ute Tribe does not elect to participate in one of the first two wells in that lease block. We will drill and operate the deep wells and our industry partner will drill and operate the shallow wells. If we fail to drill the 2005 well commitments, we are required to pay the Ute Indian Tribe $1.775 million, which is our share of the 2005 drilling obligations, and our rights to earn interests in additional acreage would terminate. Our initial exploration well in Lake Canyon is scheduled for the fourth quarter of 2005 following acquisition and evaluation of a 50 to 60 square mile 3-D seismic survey.

Brundage Canyon. In September 2004, we entered into a farm-out agreement with the same industry partner as with our Lake Canyon prospect pursuant to which we had the right to earn a 75% working interest in the deep Mesaverde formation and deeper horizons on existing exploration and development agreements that encompass 49,000 acres within the Brundage Canyon Field by drilling a deep exploration test well. This field is located on the Ute Tribe's lands and is situated adjacent to and just east of the acreage in the Lake Canyon prospect covered by our agreement with the Ute Tribe. We commenced the drilling of our initial deep exploratory well in Brundage Canyon in November 2004 and abandoned it in January 2005, pending further evaluation of a 3-D seismic survey and assessment of the optimal completion technology for the tight gas sandstone encountered by the well.

Hook

In 2004, we acquired 11,465 gross and 11,353 net acres in an exploration play that targets natural gas at depths of 1,000 feet to 4,500 feet. We plan to continue to acquire leasehold acreage through 2005.

Powder River Basin

The Powder River Basin is primarily located in northeastern Wyoming. The basin contains the Rockies' most active drilling area: the Wyodak and Big George coalbed methane plays. As of December 31, 2004, we held approximately 24,180 gross and 16,767 net developed leasehold acres and 96,717 gross and 59,587 net undeveloped leasehold acres in the Powder River Basin. Our estimated net proved reserves in the basin at year end 2004 were 40.4 Bcfe. In December 2004, we produced a net 21.0 MMcfe/d. We are focused on continuing to build and consolidate our acreage position in the Powder River Basin. Our development and exploration activities are concentrated in seven major projects in two regional focus areas: the Southern CBM and Central CBM. We also have operations in a number of smaller producing properties located in the eastern half of the basin, which we refer to collectively as the Developed Area.

Our key project areas are located in both the Big George and Wyodak fairways. We have strategically targeted areas that we believe have higher gas reserve potential and that are proximate to infrastructure. This infrastructure, in areas such as Cat Creek, Willow Creek, and Deadhorse, exists as a result of pre-existing conventional well development. Currently, we estimate our capital expenditures for 2005 will be $20.0 million, which includes participating in 219 wells, of which 39 are PUD locations, and leasehold acquisitions. As of March 11, 2005, we had all necessary drilling permits and environmental approvals in place for 103 locations of the 219 wells that are planned to be drilled in 2005. If we do not receive additional permits for the planned wells, we plan to drill other locations for which we have the necessary approvals.

Coalbed methane wells typically first produce water in a process called dewatering. This process lowers pressure, allowing the gas to detach from the coal and flow to the well bore. As the reservoir pressure declines, the wells begin producing methane gas at an increasing rate. As the wells mature, the production peaks, stabilizes and then begins declining. The average life of a coal bed well is approximately seven years. The average coal bed well in the Powder River Basin produces at a much lower rate with fewer reserves attributed to it than conventional natural gas wells in the Rockies.

We have dedicated significant resources to managing regulatory and permitting matters in the Powder River Basin to achieve efficient processing of federal permits and resource management plans.

About 72% of our acreage in the Powder River Basin is U.S. federal land and therefore subject to the National Environmental Policy Act ("NEPA") and certain state regulations, which require governmental agencies to evaluate the potential environmental impacts of a proposed project on government owned lands and minerals. The NEPA process imposes obligations on the federal government that may result in legal challenges and potentially lengthy delays in obtaining project permits or approvals. We have submitted six Federal Plans of Development ("PODs") to the BLM and United States Forest Service ("USFS") involving 470 wells. We received approval for all six of these Federal PODs, one for BLM lands in the Porcupine area for 29 wells, one for 143 wells for USFS lands in the Porcupine area, one for 36 federal wells in the Tuit project area, one for 71 wells in the Palm Tree area, one for 64 wells in the Cat Creek area, and one for 127 wells in the Deadhorse area. An application for 102 wells in Coconut Grove area that was submitted in February 2005 is pending.

Southern CBM

Tuit. The Tuit project area is located near the southern end of the Wyodak coal fairway. We believe the average thickness of the Wyodak coals across our acreage is approximately 80 feet at an average depth of 855 feet. As of December 31, 2004, we participated in drilling 74 gross wells in the Tuit area. We are the operator in this area.

As of December 31, 2004, our leasehold position in Tuit consisted of 2,185 gross and 1,602 net undeveloped acres, with an average working interest of 73%. Currently, we have a five gross well drilling program planned for 2005. Our natural gas production in Tuit is gathered by facilities owned by Western Gas Resources Inc. and sold to various parties.

Porcupine. The Porcupine project area is located southeast of Tuit on the far southern end of the Wyodak fairway. Similar to Tuit, we believe the average thickness of the Wyodak coals in this area is approximately 80 feet at an average depth of 425 feet. As of December 31, 2004, we participated in drilling 108 gross wells in the area. We are the operator in this area.

Our leasehold position in Porcupine consists of 9,565 gross and 8,194 net undeveloped acres, with an average working interest of 86% at December 31, 2004. Currently, we have an six gross well drilling program planned for 2005 in Porcupine on a combination of fee, state and federal acreage. Our natural gas production in Porcupine is gathered by facilities owned by Western Gas Resources Inc. and sold to various parties.

Palm Tree. The Palm Tree project area is located at the far southeast end of the Big George fairway and we believe overlies the highest structural position in the basin for the Big George. We believe the average thickness of the Big George coals is approximately 60 feet at an average depth of 835 feet. The Thunder Creek pipeline runs through our acreage position. Our natural gas production is gathered by facilities owned by Western Gas Resources Inc., and transported by Thunder Creek Gas Services, LLC.

We have drilled 117 gross wells in Palm Tree through December 31, 2004 and have connected 96 of these wells through December 31, 2004. Of these wells, 82 were drilled in 2004. Our leasehold position consists of 17,919 gross and 14,066 net undeveloped acres, with an average working interest of 78% at December 31, 2004. Currently, we have a 102 gross well drilling program planned for 2005.

Central CBM

Cat Creek. Cat Creek is a relatively low risk exploratory prospect area that lies on the western edge of the Big George fairway. We have drilled nine wells through December 31, 2004 on the 6,195 gross and 3,054 net acres we have under lease in the prospect area with an average working interest of 49% at December 31, 2004. We believe the average thickness of the Big George coal is approximately 90 feet at an average depth of 1,825 feet. There are three Big George pilot projects owned and operated by third parties with established production that range between four and eight miles from the prospect area. The Cat Creek area has existing road and power infrastructure due to historical conventional oil development, which should enhance our ability to keep operating costs low. In addition, the Thunder Creek gathering line runs directly through the area. We have a 58 gross well drilling program planned for 2005. We are the operator in this area.

Willow Creek. Willow Creek is a relatively low risk exploratory prospect area that is 12 miles south of the Cat Creek prospect area on the western edge of the Big George fairway. We have yet to drill any wells on the 15,403 gross and 6,509 net acres we have under lease in the Willow Creek prospect area with an average working interest of 42% at December 31, 2004. We believe the average thickness of the Big George coals is approximately 85 feet at an average depth of 1,420 feet. The Big George wells in the Kingsbury Federal Unit, which lies mid-way between Cat Creek and Willow Creek, have been producing gas for third parties. We will operate a majority of our wells in Willow Creek.

Deadhorse. The Deadhorse project area is located in an area where we believe the Big George coals and a lower split of the Wyodak coals are apparent, giving each location two coal targets. We intend to exploit cost savings on shared surface facilities and increased development efficiencies in this area. Our average working interest is 73% across 14,839 gross and 10,897 net acres in this prospect. We believe the average thickness of the Big George coal is approximately 80 feet at an average depth of 1,220 feet. We believe the Lower Wyodak coal has an average thickness of approximately 55 feet at an average depth of approximately 1,550 feet. In 2004, we drilled a five well test program to collect core and reservoir data and, as of March 11, 2005, we were analyzing the results. We intend to test the viability of a multi-seam completion in which the Big George and Lower Wyodak coals will be completed in a single well bore. We are the operator in this area.

Amos Draw. Like the Deadhorse prospect area, Amos Draw is located in an area with multiple coal targets. As of December 31, 2004, our average working interest is 36% across 4,858 gross and 1,756 net undeveloped acres. The primary target in the area is the Lower Wyodak coal, which we believe has an average thickness of 90 feet and average depth of 1,900 feet. On the western flank of the project area, both the Big George and Werner coals are viable targets. We have entered into an area of mutual interest, or AMI, agreement with several other operators in this area. There is a third party 16 to 20 well pilot project that was dewatering as of March 11, 2005 in all three potential formations immediately adjacent to the AMI. As of December 31, 2004, we participated in the drilling of nine Lower Wyodak wells, which are expected to be connected and begin dewatering this year. We are not the operator in this area.

Developed Area

In addition to our development and exploration activities in the Southern and Central CBM, we own interests in a number of smaller producing properties, which we refer to collectively as the Developed Area. Most of these properties were acquired as a part of a development oriented acquisition. They are generally located in the eastern half of the Powder River Basin and include Little Buffalo Ranch, Goer, Pronghorn, South Coal Gulch, Terra and Kitty. As of December 31, 2004, we had interests in 224 gross and 104 net producing wells in this area, which included 177 gross and 95 net CBM wells and 47 gross and 14 net conventional wells. Our estimated net proved reserves in the Developed Area were 1.6 Bcfe at December 31, 2004.

Williston Basin

The Williston Basin is located in western North Dakota, northwestern South Dakota and eastern Montana. It is a predominantly oil prone basin and produces oil and natural gas from 11 major geologic horizons that range in depth from approximately 1,000 to over 14,000 feet.

While we have interests in a substantial number of wells in the Williston Basin, which target several different zones, our exploration and development activities currently are concentrated on three of the producing formations, the Madison, Bakken and the Red River. The application of horizontal completions in these formations has yielded significant improvement in the recovery of hydrocarbons from reservoirs compared to vertically drilled well completions in the same type of formations. The basin has established infrastructure and access to materials and services. Regulatory delays are less prevalent than other areas due to fee ownership of properties, more efficient state and local regulatory bodies and more reasonable permitting requirements.

Our total leasehold position in the Williston Basin as of December 31, 2004 consisted of 179,259 gross and 113,403 net undeveloped acres and 12,141 gross and 7,472 net developed acres. Our estimated net proved reserves in the Williston Basin were 31 Bcfe at year end 2004. As of December 31, 2004, we had 31 net producing wells and production of 6.3 MMcfe/d for December 2004, with an average working interest of 39.7%. Our average working interest in the wells we operate is approximately 92%. We participated in the drilling of nine horizontal wells in 2004 as part of our 2004 capital program of $20 million in this area. Currently, we estimate our capital expenditures for 2005 will be $9.2 million in the Williston Basin, which includes drilling six horizontal wells and one recompletion. We are seeking an industry partner to enter into joint exploration or drilling agreements and to sell up to 50% of our interests in up to 57,892 net undeveloped acres in certain of our Williston projects to industry partners. If we are successful in obtaining industry partners and selling interests in these prospects, we plan to participate in the drilling of three Madison, one Bakken and two Red River exploration wells. Our oil is stored in tanks located at the wellsite and periodically collected by independent oil purchasers.

Madison

Our development projects within the Madison area lie within the central Williston Basin along the Montana and North Dakota border. The majority of our properties, both producing and prospective, are located within a 50-mile radius of Williston, North Dakota, the major industry service center for the area. The tight concentration of assets and proximate location to a service center allows for efficient operations. Our drilling program targets the Madison formations at depths of 9,000 to 9,500 feet and the Bakken formation at depths of 7,500 to 10,500 feet. Our wells are drilled vertically 7,500 to 10,500 feet and then extended laterally up to 5,000 feet through the formation. As of December 31, 2004, we held 100,132 gross and 66,613 net leasehold acres in the area. In 2004, we drilled nine horizontal Madison wells. Eight were producing successfully and one was determined to be a dry hole. In addition, we determined the Karst 33-5 development well, drilled in 2003, was a dry hole.

Red River

Our Red River area lies along the North and South Dakota border on the southern flank of the Williston Basin. Within this area, we target the B Zone porosity of the Red River formation at approximately 9,300 feet. We believe Red River B porosity is a uniform, widespread, seven to eight feet thick reservoir unit present across the area. The B Zone is one of the primary producing zones along the Cedar Creek Anticline, which trends northwest from our acreage.

Our total leasehold position in Red River consisted of 22,281 gross and 17,102 net undeveloped acres and 957 gross and 255 net developed acres, with an average working interest of 75% at December 31, 2004. Our exploration drilling program in Red River is scheduled to begin in 2005 after selling interests to industry partners. Our wells will be drilled vertically 9,000 to 9,400 feet and then extended laterally up to 5,000 feet through the formation.

Green River Basin

The Green River Basin is located in southwestern Wyoming and adjacent areas of northeastern Utah. Two of the Rockies largest gas fields are in the Green River Basin, the Pinedale Anticline and Jonah.

Antelope Hollow

Our total leasehold position in the Antelope Hollow exploration project consists of 13,297 gross and 7,977 net undeveloped acres as of December 31, 2004. The Antelope Hollow prospect is a seismically defined, anticlinal feature. We are participating as non-operator in an 18,250 foot Dakota test, with a 40% working interest. This well commenced drilling on February 2, 2005 and, as of March 11, 2005, was drilling ahead. We may evaluate several other potentially productive formations uphole. We currently plan a $2 million capital program in this area in 2005 to drill this exploratory well. Subsequent to December 31, 2004, we have offered our working interest partner the opportunity to purchase a 60% interest in three leases covering 4,518 gross and net acres.

Denver-Julesburg Basin

The DJ Basin covers parts of Colorado, Wyoming, Nebraska and Kansas and contains the well known Wattenberg field. Other operators have established production in the Wattenberg field from multiple zones, including the Niobrara formation at depths of 7,000 feet.

Tri-State

Our exploration program focuses on the eastern side of the DJ Basin, which we refer to as our Tri-State area (which includes portions of northeastern Colorado, southwestern Nebraska and northwestern Kansas) and targets the biogenic shale gas potential of the Sharon Springs Member of the Pierre Formation and the biogenic gas potential of the underlying Niobrara Formation at depths less than 2,000 feet, and the conventional oil potential of Kansas City-Lansing, Marmaton, and Cherokee Formations of the Pennsylvanian System at depths of 4,000 to 4,800 feet. If successful, production can be sold into an already established interstate pipeline network.

We believe the Niobrara potential of the Tri-State area can be exploited with 3-D seismic "bright spot" and horizontal drilling technologies. Our project capital expenditures for 2003 and 2004 were $6.3 million for the purchase of 367,000 gross (346,000 net) acres and the acquisition of 224 miles of 2-D and 24 square miles of 3-D seismic.

On January 28, 2005, we sold a 50% working interest in our Tri-State leasehold to an industry partner and entered into an agreement to jointly explore this area. In 2005, we anticipate acquiring additional 2-D seismic and drilling two exploration wells (one vertical and one horizontal) as part of a $2.5 million (gross) capital expenditure in this area. As a result of the sale to our industry partner, we now have interests in 367,426 gross and 173,011 net undeveloped acres in the Tri-State area.

Paradox Basin

The Paradox Basin is located in southwestern Colorado and southeastern Utah, and is adjacent to the San Juan Basin of New Mexico and Colorado. Although the Paradox Basin is generally considered to be an oil prone basin, the application of 3-D seismic and new drilling fluid technology has enabled other operators to commercialize a new gas play in the Lower Honaker Trail formation in

San Miguel County, Colorado.

Pine Ridge

One of our project areas in the Paradox Basin is the Pine Ridge exploration prospect, which is a very early stage exploration concept. We are exploring for gas fields in stratigraphic traps associated with salt diapirs, a geological structure feature characterized by salt intrusion into a rock formation from below. As of December 31, 2004, we had interests in 2,042 gross acres and 1,960 net acres in the Pine Ridge prospect, located in San Juan County, Utah. We intend to build our acreage position in this play through acquisitions or other arrangements with acreage owners in the area. We also are in discussions with the U.S. Forest Service and the Bureau of Land Management as we begin the permitting process for a 20 square mile 3-D seismic survey that we have targeted for 2005.

Yellow Jacket

In 2004, we acquired 13,118 gross acres and 8,044 net acres in Yellow Jacket. This prospect will target natural gas from a fractured shale reservoir at depths of 4,500 to 6,500 feet. Currently, we have not budgeted any capital expenditures for 2005.

Big Horn Basin

We recently began building an exploratory position in the Big Horn Basin. The Big Horn Basin is located in north central Wyoming and lies west and north of the Powder River and Wind River Basins, respectively. Although the Big Horn Basin is largely considered an oil prone basin, we are pursuing both conventional stratigraphic and structural gas plays, as well as unconventional basin-centered type gas plays in the basin. As of December 31, 2004, we had leasehold interests in 192,799 gross and 145,442 net undeveloped acres in the Big Horn Basin.

Oil and Gas Data

Proved Reserves

The following table presents our estimated net proved natural gas and oil reserves and the present value of our estimated proved reserves at each of December 31, 2002, 2003, and 2004 based on reserve reports prepared by us and reviewed in their entirety by our independent petroleum engineers. All our proved reserves included in the reserve report are located in North America. Ryder Scott Company, L.P. reviews all our reserve estimates except for our reserve estimates in the Powder River Basin, which are reviewed by Netherland, Sewell & Associates, Inc. When compared on a well-by-well or lease-by-lease basis, some of our estimates of net proved reserves are greater and some are less than the estimates of our independent petroleum engineers. However, our internal estimates of total net proved reserves are within 10% of those estimated by our independent petroleum engineers. Our estimates of net proved reserves have not been filed with or included in reports to any federal authority or agency other than the Securities and Exchange Commission in connection with our registration statement for our initial public offering. The PV-10 and Standardized Measure shown in the table are not intended to represent the current market value of our estimated natural gas and oil reserves.

	As of December 31,		
	2002	2003	2004
Estimated Net Proved Reserves (1):			
Natural gas (Bcf)	101.8	180.9	257.8
Oil (MMBbls)	2.9	3.9	5.7
Total (Bcfe)	119.1	204.2	292.3
Percent proved developed	75.1%	62.5%	61.1%
PV-10 (in millions) (2)	$ 178.6	$ 520.8	592.1
Standardized Measure (in millions) (3)	153.5	404.8	466.1

---

(1) Excludes estimated proved reserves of 10.9 Bcfe with a PV-10 of $17.8 million related to properties held for sale as of December 31, 2002.

(2) Represents present value, discounted at 10% per annum, of estimated future net cash flows before income tax of our estimated proved reserves. In accordance with SEC requirements, our reserves and the future net revenues were determined using market prices for natural gas and oil at each of December 31, 2002, 2003, and 2004, which were $3.12 per MMBtu of gas and $31.35 per

barrel of oil at December 31, 2002, $5.58 per MMBtu of gas and $32.55 per barrel of oil at December 31, 2003, and $5.52 per MMBtu of gas and $43.46 per barrel of oil at December 31, 2004. Includes PV-10 of $17.8 million associated with proved reserves for properties held for sale at December 31, 2002. These prices were adjusted by lease for quality, transportation fees and regional price differences. Giving effect to hedging transactions based on prices current at such dates, our PV-10 would have been $196.8 million at December 31, 2002, $505.7 million at December 31, 2003 and $588 million at December 31, 2004.

(3) The Standardized Measure represents the present value of estimated future cash inflows from proved natural gas and oil reserves, less future development, production, and income tax expenses, discounted at 10% per annum to reflect timing of future cash flows and using the same pricing assumptions as were used to calculate PV-10. Standardized Measure differs from PV-10 because Standardized Measure includes the effect of future income taxes.

Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are proved reserves that are expected to be recovered from new wells drilled to known reservoirs on undrilled acreage for which the existence and recoverability of such reserves can be estimated with reasonable certainty, or from existing wells on which a relatively major expenditure is required to establish production.

The data in the above table represents estimates only. Oil and natural gas reserve engineering is inherently a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured exactly. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of oil and natural gas that are ultimately recovered. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Risk Factors".

Our independent engineers, Ryder Scott Company, L.P. and Netherland, Sewell & Associates, Inc., perform a well-by-well review of all of our properties and of our estimates of proved reserves and then provide us with their review reports concerning our estimates. Ryder Scott Company, L.P. provided us with a report stating its opinion that the methods and techniques used in preparing our reserve report are in accordance with generally accepted procedures for the determination of reserves, and that, in its judgment, there was no evidence of bias in the application of the methods and techniques for estimating proved reserves, and that the total proved net reserves estimated would be within 10% of those estimated by Ryder Scott Company, L.P. Netherland, Sewell & Associates, Inc. stated in its report that our estimates of proved oil and gas reserves and future revenue as shown in its report and in certain computer printouts in its office are, in the aggregate, reasonable and have been prepared in accordance with generally accepted petroleum engineering and evaluation principles. These review reports do not state the degree of their concurrence with the accuracy of our estimate for the proved reserves attributable to our interest in any specific basin, property or well, although this information is generated by the independent engineers as a basis for their review report.

Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The PV-10 shown should not be construed as the current market value of the reserves. The 10% discount factor used to calculate present value, which is required by Financial Accounting Standard Board pronouncements, is not necessarily the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate.

From time to time, we engage Ryder Scott Company, L.P. and Netherland, Sewell & Associates, Inc. to review and/or evaluate the reserves of properties that we are considering purchasing and to provide technical consulting on well testing. Neither Ryder Scott Company, L.P. nor Netherland, Sewell & Associates, Inc. nor any of their respective employees has any interest in those properties and the compensation for these engagements is not contingent on their estimates of reserves and future cash inflows for the subject properties. During 2004, we paid Ryder Scott Company, L.P. $31,616 for reviewing our reserve estimates and $29,840 for other consulting services. During 2004, we paid Netherland, Sewell & Associates, Inc. $66,010 for reviewing our reserve estimates and $79,232 for other consulting services.

Production and Price History

The following table sets forth information regarding net production of oil, natural gas and natural gas liquids, and certain price and cost information for each of the periods indicated:

	Period from January 7, 2002 (inception) through December 31, 2002 (1)	Year Ended December 31, 2003	Year Ended December 31, 2004
Production Data:			
Natural gas (MMcf) (2)	6,371	16,315	28,864
Oil (MBbls)	30	328	474
Combined volumes (MMcfe)	6,551	18,283	31,708
Daily combined volumes (MMcfe/d)	23.6	50.1	86.6
Average Prices (3):			
Natural gas (per Mcf)	$ 2.39	$ 4.03	$ 5.10
Oil (per Bbl)	25.39	28.85	39.49
Combined (per Mcfe)	2.44	4.12	5.23
Average Costs (per Mcfe):			
Lease operating expense	$ 0.34	$ 0.46	$ 0.46
Gathering and transportation expense	0.03	0.20	0.19
Production tax expense	0.31	0.54	0.63
Depreciation, depletion and amortization	1.40	1.68	2.15
General and administrative (4)	0.84	0.78	0.57

(1) In the period ended December 31, 2002, production commenced on March 29, 2002 following the purchase of our first properties.

(2) Production of natural gas liquids is included in natural gas revenues and production. Production data excludes production associated with properties held for sale.

(3) Includes the effects of hedging transactions, which reduced average gas prices by $0.48 per Mcf in 2003 and $0.43 per Mcf in 2004.

(4) Excludes non-cash stock-based compensation expense.

Productive Wells

The following table sets forth information at December 31, 2004, relating to the productive wells in which we owned a working interest as of that date. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have an interest, and net wells are the sum of our fractional working interests owned in gross wells.

	Gas		Oil	
Basin	**Gross Wells**	**Net Wells**	**Gross Wells**	**Net Wells**
Piceance	93	86.2	—	—
Wind River	144	132.9	2	1.5
Uinta	23	19.2	—	—
Powder River (1)	349	273.4	42	8.5
Williston	—	—	90	30.5
Total	609	511.7	134	40.5

(1) The five wells that had completions in more than one zone are each shown as only one gross well.

Developed and Undeveloped Acreage

The following table sets forth information as of December 31, 2004 relating to our leasehold acreage.

Basin	Developed Acreage (1) Gross (3	Developed Acreage (1) Net (4)	Undeveloped Acreage (2) Gross (3)	Undeveloped Acreage (2) Net (4)
Piceance Basin	9,289	7,156	12,812	10,031
Wind River	7,251	5,936	388,172	165,946
Uinta	6,118	5,811	134,036	96,672 (5)
Powder River	24,180	16,767	96,717	59,587
Williston	12,141	7,472	179,259	113,403
Green River(6)	—	—	13,297	7,977
Denver-Julesburg(7)	—	—	367,426	346,022
Paradox	—	—	15,160	10,004
Big Horn	2,721	1,680	192,799	145,442
Other	1,941	244	51,838	16,002
Total	63,641	45,066	1,451,516	971,086(5)

(1) Developed acres are acres spaced or assigned to productive wells.

(2) Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.

(3) A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

(4) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

(5) An additional 161,750 net undeveloped acres that are subject to drill-to-earn agreements are not included.

(6) Subsequent to December 31, 2004, we have offered our working interest partner the opportunity to purchase a 60% interest in three leases covering 4,518 gross and net acres.

(7) Subsequent to December 31, 2004, we entered into a joint exploration agreement with respect to our Tri-State prospect and sold a 50% interest in that prospect. As of March 1, 2005, we hold 173,011 net undeveloped leasehold acres in that project area.

Many of the leases comprising the undeveloped acreage set forth in the table above will expire at the end of their respective primary terms unless production from the leasehold acreage has been established prior to such date, in which event the lease will remain in effect until the cessation of production. We generally have been able to obtain extensions of the primary terms of our federal leases for the period that we have been unable to obtain drilling permits due to a pending EA, Environmental Impact Statement or related legal challenge. The following table sets forth as of September 30, 2004 the expiration periods of the gross and net acres that are subject to leases summarized in the above table of undeveloped acreage.

Twelve Months Ending:	Undeveloped Acres Expiring Gross	Undeveloped Acres Expiring Net
December 31, 2005	128,411	80,118
December 31, 2006	58,254	34,949
December 31, 2007	156,903	107,720
December 31, 2008	429,859	371,015
December 31, 2009 and later (1)	678,089	377,284
Total	1,451,516	971,086

(1) Includes 352,104 gross and 175,390 net undeveloped acres held by production from other leasehold acreage or held by federal units.

Drilling Results

The following table sets forth information with respect to wells completed during the periods indicated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of hydrocarbons, regardless of whether they produce a reasonable rate of return.

	Period from January 7, 2002 (inception) through December 31, 2002		Year Ended December 31, 2003		Year Ended December 31, 2004(1)	
	Gross	Net	Gross	Net	Gross	Net
Development						
Productive	—	—	50	41.5	150	147.9
Dry	—	—	1	0.9	2	1.7
Exploratory						
Productive	3	2.8	39	35.8	93	79.9
Dry	—	—	2	1.6	13	10.0
Total						
Productive	3	2.8	89	77.3	243	227.8
Dry	—	—	3	2.5	15	11.7

(1) The determination of development and exploratory wells shown in the table above is based on an interpretation of the definitions of those terms in Rule 4-10(a) of Regulation S-X, which governs financial disclosures in filings with the SEC, that includes as development wells only those wells drilled on drilling locations to which proved undeveloped, or PUD, reserves have been attributed at the time at which drilling of the well commenced, and in which all other wells are considered exploratory. We also are providing information with respect to drilling results in which development wells include not only wells drilled on PUD locations but also wells drilled in a proved area in which proved reserves have been attributed by our reservoir engineers as of the time of commencement of drilling. On this basis, during 2004, we completed 236 gross (222.6 net) productive and 8 gross (7.1 net) dry development wells and 7 gross (4.2 net) productive and 7 gross (5.0 net) dry exploratory wells.

From inception through December 31, 2004, we participated in drilling 474 gross wells, of which 335 were completed as producing, 121 were in process of completing or dewatering and 18 were dry holes. Also during that time, we recompleted 46 gross wells, which are not included in the totals above.

Operations

General

In general, we serve as operator of wells in which we have a greater than 50% interest. In addition, we seek to be operator of wells in which we have lesser interests. As operator, we design and manage the development of a well and supervise operation and maintenance activities on a day-to-day basis. We do not own drilling rigs or other oil field services equipment used for drilling or maintaining wells on properties we operate. Independent contractors engaged by us provide all the equipment and personnel associated with these activities. We employ drilling, production, and reservoir engineers, geologists and other specialists who work to improve production rates, increase reserves, and lower the cost of operating our natural gas and oil properties.

Marketing and Customers

We market the majority of the natural gas and oil production from properties we operate for both our account and the account of the other working interest owners in these properties. We sell the majority of our production to a variety of purchasers under short-term contracts or spot gas purchase contracts ranging anywhere from one day to seven months, all at market prices. We have one long-term contract to sell natural gas at market rates through December 2007. The gas volumes subject to this agreement are negotiated annually and currently are 22.5 MMBtu/d. We normally sell production to a relatively small number of customers, as is customary in the exploration, development and production business. However, based on the current demand for natural gas and oil and availability of other purchasers, we believe that the loss of any one or all of our major purchasers would not have a material adverse effect on our financial condition and results of operations. For a list of our purchasers that accounted for 10% or more of our natural gas and oil revenues during the last two calendar years, see "Notes to Consolidated Financial Statements—Note 12—Significant Customers and Other Concentrations".

We enter into hedging transactions with unaffiliated third parties for portions of our natural gas production to achieve more predictable cash flows and to reduce our exposure to short-term fluctuations in gas prices. For more a detailed discussion, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Overview" and "—Quantitative and Qualitative Disclosures About Market Risk".

We incur gathering and transportation expenses to move our natural gas from the wellhead to a purchaser-specified delivery point. These expenses vary based on the volume and distance shipped, and the fee charged by the third party transporter. We have three firm transportation agreements. The first agreement is with Questar Pipeline Company for 8,500 MMBtu/d of guaranteed pipeline capacity at a monthly charge of $45,000 for one year beginning in March 2004. The second agreement is with Cheyenne Plains Company for 9,000 MMBtu of guaranteed pipeline capacity for 12 years and three months beginning with our first shipments of gas in February 2005, with an annual commitment of $1,117,000 and for 5,000 MMBtu/d of guaranteed pipeline capacity for an additional year thereafter. The third agreement is with Questar Pipeline Company for 12,000 MMBtu/d of guaranteed pipeline capacity at a monthly charge of $94,000 per month for ten years beginning upon the completion of Questar's upgrade of its pipeline in the Piceance Basin, which is expected to be completed in November 2005. Our natural gas and oil are transported through third party gathering systems and pipelines. Transportation space on these gathering systems and pipelines is occasionally limited and at times unavailable because of repairs or improvements, or as a result of priority transportation agreements with other gas shippers. While our ability to market our natural gas has been only infrequently limited or delayed, if transportation space is restricted or is unavailable, our cash flow from the affected properties could be adversely affected.

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices. Our larger or integrated competitors may be able to absorb the burden of existing, and any changes to, federal, state, local and Native American tribal laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties.

Title to Properties

As is customary in the oil and gas industry, we initially conduct only a cursory review of the title to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property. We have obtained title opinions on substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and gas industry. Prior to completing an acquisition of producing natural gas and oil leases, we perform title reviews on the most significant leases and, depending on the materiality of properties, we may obtain a title opinion or review previously obtained title opinions. Our natural gas and oil properties are subject to customary royalty and other interests, liens for current taxes and other burdens which we believe do not materially interfere with the use of or affect our carrying value of the properties.

Seasonal Nature of Business

Generally, but not always, the demand for natural gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or hot summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. Seasonal weather conditions and lease stipulations can limit our drilling and producing activities and other oil and natural gas operations in certain areas of the Rocky Mountain region. These seasonal anomalies can pose challenges for meeting our well drilling objectives and increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations. For an example of drilling reductions, see "Uinta Basin — West Tavaputs".

Environmental Matters and Regulation

General. Our operations are subject to stringent federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Our operations are subject to the same environmental laws and regulations as other companies in the oil and gas exploration and production industry. These laws and regulations may:

- require the acquisition of various permits before drilling commences;
- require the installation of expensive pollution control equipment;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on lands lying within wilderness, wetlands and other protected areas;
- require remedial measures to prevent pollution from former operations, such as pit closure and plugging of abandoned wells;
- impose substantial liabilities for pollution resulting from our operations; and
- with respect to operations affecting federal lands or leases, require preparation of a Resource Management Plan, an Environmental Assessment, and/or an Environmental Impact Statement.

These laws, rules and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and the federal and state agencies frequently revise the environmental laws and regulations, and any changes that result in more stringent and costly waste handling, disposal and clean-up requirements for the oil and gas industry could have a significant impact on our operating costs. We believe that we substantially comply with all current applicable environmental laws and regulations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. However, we cannot predict the passage of or quantify the potential impact of more stringent future laws and regulations at this time. For the year ended December 31, 2004, we did not incur any material capital expenditures for installation of remediation or pollution control equipment at any of our facilities.

The environmental laws and regulations which could have a material impact on the oil and natural gas exploration and production industry are as follows:

National Environmental Policy Act. Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act, or NEPA. NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will have an EA prepared that assesses the potential direct, indirect and cumulative impacts of a proposed project. If impacts are considered significant, the BLM will prepare a more detailed EIS that may be made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of oil and natural gas projects.

Waste Handling. The Resource Conservation and Recovery Act, or RCRA, and comparable state statutes, affect oil and gas exploration and production activities by imposing regulations on the generation, transportation, treatment, storage, disposal and cleanup of "hazardous wastes" and on the disposal of non-hazardous wastes. Under the auspices of the Environmental Protection Agency, or EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of crude oil, natural gas, or geothermal energy constitute "solid wastes", which are regulated under the less stringent non-hazardous waste provisions, but there is no guarantee that the EPA or the individual states will not adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous for future regulation. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and gas exploration and production wastes as "hazardous wastes".

As of March 11, 2005, we believe that we were in substantial compliance with the requirements of RCRA and related state and local laws and regulations, and that we held all necessary and up-to-date permits, registrations and other authorizations to the extent that our operations require them under such laws and regulations. Although we believe the current costs of managing our wastes as they are presently classified are not significant and are reflected in our budget, any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase our costs to manage and dispose of such wastes.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "superfund" law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site, or site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substance. Under CERCLA, such persons may be subject to joint and several liability 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 landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. In the course of our operations, we use materials, that, if released, would be subject to CERCLA. Therefore, governmental agencies or third parties may seek to hold us responsible under CERCLA for all or part of the costs to clean up sites at which such "hazardous substances" have been deposited.

Water Discharges. The Federal Water Pollution Control Act, also known as the Clean Water Act, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other oil and gas wastes, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by EPA or the state. These prescriptions also prohibit the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by a permit issued by the U.S. Army Corps of Engineers. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the federal Clean Water Act and analogous state laws and regulations. We maintain all required discharge permits necessary to conduct our operations, and we believe we are substantial compliance with the terms thereof. Obtaining permits has the potential to delay the development of oil and natural gas projects.

Air Emissions. The Federal Clean Air Act, and associated state laws and regulations, regulate emissions of various air pollutants through the issuance of permits and the imposition of other requirements. In addition, EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. Some of our new facilities may be required to obtain permits before work can begin, and existing facilities may be required to incur capital costs in order to remain in compliance. These regulations may increase the costs of compliance for some facilities federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. We believe that we are in substantial compliance with all air emissions regulations and that we hold all necessary and valid construction and operating permits for our operations. Obtaining permits has the potential to delay the development of oil and natural gas projects.

Other Laws and Regulation. In 1997, numerous countries reached agreement on the Kyoto Protocol to the United Nations Framework Convention on Climate Change. If the Protocol enters into force, adopting countries would be required to implement national programs to reduce emissions of certain gases, generally referred to as greenhouse gases, that are suspected of contributing to global warming. The Bush administration has indicated it will not support ratification of the Protocol, and Congress has resisted recent proposed legislation directed at reducing greenhouse gas emissions. However, there has been support in various regions of the country for legislation that requires reductions in greenhouse gas emissions, and some states have already adopted legislation addressing greenhouse gas emissions from certain greenhouse gas emission sources, primarily power plants. The oil and natural 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 are not adversely impacted by current state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business.

Legislation continues to be introduced in Congress and development of regulations continues in the Department of Homeland Security and other agencies concerning the security of industrial facilities, including oil and natural gas facilities. Our operations may be subject to such laws and regulations. Presently, it is not possible to accurately estimate the costs we could incur to comply with any such facility security laws or regulations, but such expenditures could be substantial.

Other Regulation of the Oil and Gas Industry

The oil and gas industry is extensively regulated by numerous federal, state and local authorities, including Native American tribes. Legislation affecting the oil and gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, and Native American tribes are authorized by statute to issue rules and regulations binding on the oil and gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

Drilling and Production. Our operations are subject to various types of regulation at federal, state, local and Native American tribal levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties, municipalities and Native American tribes, in which we operate also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the rates of production or "allowables";
- the surface use and restoration of properties upon which wells are drilled and other third parties;
- the plugging and abandoning of wells; and
- notice to, and consultation with, surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of natural gas and oil we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

Natural Gas Sales Transportation. Historically, federal legislation and regulatory controls have affected the price of the natural gas we produce and the manner in which we market our production. The Federal Energy Regulatory Commission, or FERC, has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce by natural gas companies under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Since 1978, various federal laws have been enacted which have resulted in the complete removal of all price and non-price controls for sales of domestic natural gas sold in "first sales", which include all of our sales of our own production.

FERC also regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Commencing in 1985, FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. FERC's initiatives have led to the development of a competitive, unregulated, open access market for gas purchases and sales that permits all purchasers of gas to buy gas directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated; therefore, we cannot guarantee that the less stringent regulatory approach recently pursued by FERC and Congress will continue indefinitely into the future nor can we determine what affect, if any, future regulatory changes might have on our natural gas related activities.

Under FERC's current regulatory regime, transmission services must be provided on an open-access, non-discriminatory basis at cost-based rates or at market-based rates if the transportation market at issue is sufficiently competitive. Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by state agencies. Although its policy is still in flux, FERC recently has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of getting gas to point-of-sale locations.

Operations on Native American Reservations. A portion of our leases in the Uinta basin are, and some of our future leases in this and other areas may be, regulated by Native American tribes. In addition to regulation by various federal, state and local agencies and authorities, an entirely separate and distinct set of laws and regulations applies to lessees, operators and other parties within the boundaries of Native American reservations. Various federal agencies within the U.S. Department of the Interior, particularly the Minerals Management Service and the Bureau of Indian Affairs, together with each Native American tribe, promulgate and enforce regulations pertaining to oil and gas operations on Native American reservations. These regulations include lease provisions, royalty matters, drilling and production requirements, environmental standards, and numerous other matters.

Native American tribes are subject to various federal statutes and oversight by the Bureau of Indian Affairs. However, each Native American tribe is a sovereign nation and has the right to enforce certain other laws and regulations entirely independent from federal, state and local statutes and regulations, as long as they do not supersede or conflict with such federal statutes. These tribal laws and regulations include various fees, taxes, requirements to employ Native American tribal members, and numerous other conditions that apply to lessees, operators, and contractors conducting operations within the boundaries of an Native American reservation. Further, lessees and operators within an Native American reservation are subject to the Native American tribal court system, unless there is a specific waiver of sovereign immunity by the Native American tribe allowing resolution of disputes between the Native American tribe and those lessees or operators to occur in federal or state court.

Therefore, we are subject to various laws and regulations pertaining to Native American tribal surface ownership, Native American oil and gas leases, fees, taxes, and other burdens, obligations and issues unique to oil and gas ownership and operations within Native American reservations. One or more of these requirements may increase our costs of doing business on Native American tribal lands and have an impact on the economic viability of any well or project on those lands.

Employees

As of March 1, 2005, we had 150 full time employees, including 17 geologists and geophysicists, 16 petroleum engineers and eight land and regulatory professionals. Of our 150 full time employees, 106 work in our Denver office and 44 are in our district and field offices. We also contract for the services of independent consultants involved in land, regulatory, accounting, financial and other disciplines as needed. None of our employees are represented by labor unions or covered by any collective bargaining agreement. We believe that our relations with our employees are satisfactory.

Offices

As of March 11, 2005, we leased approximately 39,400 square feet of office space in Denver, Colorado at 1099 18th Street, where our principal offices are located. The lease for our Denver office expires in January 2009. We also have field offices in or near the Cave Gulch field and Gillette, Wyoming, Parachute, Colorado, and Roosevelt, Utah. We believe that our facilities are adequate for our current operations and that additional leased space can be obtained if needed.

Website and Code of Business Conduct and Ethics

Our website address is http://www.billbarrettcorp.com. We make available free of charge through our website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with or furnished to the SEC at http://www.sec.gov. Additionally, our Code of Business Conduct and Ethics, which includes our code of ethics for senior financial management, Corporate Governance Guidelines and the charters of our Audit Committee, Compensation Committee and Nominating and Corporate Governance Committee are posted on our website at http://www.billbarrettcorp.com and are available in print free of charge to any stockholder who requests them. Requests should be sent by mail to our corporate secretary at our principal office at 1099 18th Street, Suite 2300, Denver, Colorado 80202.

GLOSSARY OF OIL AND NATURAL GAS TERMS

The following is a description of the meanings of some of the oil and natural gas industry terms used in this Annual Report on Form 10-K.

3-D seismic. Geophysical data that depict the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D, or two-dimensional, seismic.

AMI. Area of mutual interest.

Basin-centered gas. A regional abnormally-pressured, gas-saturated accumulation in low-permeability reservoirs lacking a down-dip water contact.

Bbl. Stock tank barrel, or 42 U.S. gallons liquid volume, used in this Annual Report on Form 10-K in reference to crude oil or other liquid hydrocarbons.

Bbl/d. Bbl per day.

Bcf. Billion cubic feet of natural gas.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Biogenic gas. Bacteria-generated natural gas usually found at depths of a few hundred to a few thousand feet because it is formed at the low temperatures that accompany the shallow burial and rarely is generated at depths greater that 3,000 feet.

Boe. Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.

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

Coalbed methane (CBM). Natural gas formed as a byproduct of the coal formation process, which is trapped in coal seams and produced by non-traditional means.

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

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

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

Development well. A well drilled within the proved area of a natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.

Discontinuous lenticular sands. Sandstone reservoirs that have a limited aerial extent. In general these types of sandstones will be encountered by separate wellbores infrequently in a given area depending on well density. By comparison, a continuous or blanket sandstone may be encountered repeatedly by multiple wellbores in a given area.

Down-dip. The occurrence of a formation at a lower elevation than a nearby area.

Drill-to-earn. The process of earning an interest in leasehold acreage by drilling a well pursuant to a farm-in or exploration agreement.

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

Environmental Assessment (EA). An environmental assessment, a study that can be required pursuant to federal law prior to drilling a well.

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

Farm-in or farm-out. An agreement under which the owner of a working interest in a natural gas and oil lease assigns the working interest or a portion of the working interest to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a "farm-in" while the interest transferred by the assignor is a "farm-out".

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

Finding and Development Costs. Capital costs incurred in the acquisition, exploitation and exploration of proved oil and natural gas reserves divided by proved reserve additions and revisions to proved reserves.

Fractured shale gas. Gas that is present in fractures in a formation consisting mostly of shale.

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

Horizontal re-entry well. A new well in which a pre-existing wellbore is used as the starting point of a new horizontal borehole. Drilling a horizontal re-entry well typically involves milling a hole in the casing of the pre-existing wellbore and drilling hundreds or thousands of feet from the pre- existing wellbore.

Infill drilling. The drilling of wells between established producing wells on a lease to increase reserves or productive capacity from the reservoir.

MBbls. Thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. Thousand cubic feet of natural gas.

Mcf/d. Mcf per day.

Mcfe. Thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMBbls. Million barrels of crude oil or other liquid hydrocarbons.

MMboe. Million barrels of oil equivalent.

MMBtu. Million British Thermal Units.

MMcf. Million cubic feet of natural gas.

MMcf/d. MMcf per day.

MMcfe. Million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMcfe/d. MMcfe per day.

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

Overpressured. A subsurface formation that exerts an abnormally high formation pressure on a wellbore drilled into it.

PDNP. Proved developed nonproducing.

PDP. Proved developed producing.

Plugging and abandonment. Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.

PUD. Proved undeveloped.

Present value of future net revenues (PV-10). The present value of estimated future revenues to be generated from the production of proved reserves, before income taxes, of proved reserves calculated in accordance with Financial Accounting Standards Board guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, and discounted using an annual discount rate of 10%.

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

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved developed reserves (PDP). Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

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

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

PV-10. The present value, discounted at 10% per annum, of estimated future net cash flows before income tax of estimated proved reserves.

Recompletion. The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

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

Standardized Measure. The present value of estimated future cash inflows from proved natural gas and oil reserves, less future development and production costs and future income tax expenses, discounted at 10% per annum to reflect timing of future cash flows and using the same pricing assumptions as were used to calculate PV-10. Standardized Measure differs from PV-10 because Standardized Measure includes the effect of future income taxes.

Stratigraphic play. An oil or natural gas formation contained within an area created by permeability and porosity changes characteristic of the alternating rock layer that result from the sedimentation process.

Structural play. An oil or natural gas formation contained within an area created by earth movements that deform or rupture (such as folding or faulting) rock strata.

Tight gas sands. A formation with low permeability that produces natural gas with very low flow rates for long periods of time.

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

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

Item 3. Legal Proceedings

We are not a party to any material pending legal or governmental proceedings, other than ordinary routine litigation incidental to our business. While the ultimate outcome and impact of any proceeding cannot be predicted with certainty, our management believes that the resolution of any proceeding will not have a material adverse effect on our financial condition or results of operations.

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

During the quarter ended December 31, 2004, but prior to the time that the Company became a reporting company under the Securities Exchange Act, the Company's securities holders approved the following matters by written consent on the dates indicated.

December 1, 2004

The stockholders approved our 2004 Stock Incentive Plan, which is described below in "Item 11. Executive Compensation".

December 6, 2004

The stockholders approved (1) a Certificate of Amendment to our Certificate of Incorporation that reduced the number of authorized shares of Series B Preferred Stock from 52,185,000 to 51,951,418 and to prohibit the reissuance of shares of Series B Preferred Stock that are purchased or otherwise acquired by the Company; (2) a Restated Certificate of Incorporation that reflected amendments made to the Certificate of Incorporation in anticipation of our initial public offering, combined previous amendments and referenced the reverse stock split undertaken in connection with our initial public offering; (3) the Certificate of Designations setting forth the rights of our Series A Junior Participating Preferred Stock for our shareholder rights plan; and (4) our bylaws.

December 9, 2004

The stockholders approved a revised version of our Restated Certificate of Incorporation with a larger possible range of our reverse stock split.

Each of these matters was approved by the holders of the following securities, representing a majority of the voting power at each respective approval date. The shares of Series A Preferred Stock and Series B Preferred Stock automatically converted into shares of common stock upon the completion of our initial public offering on December 15, 2004.

Security	Votes For	Votes Against or Withheld	Abstentions (includes shares not asked to vote)	Broker Non-Votes
Common Stock	7,083,850	0	1,383,798	0
Series A Preferred Stock	1,760,957	0	4,498,036	0
Series B Preferred Stock	34,473,708	0	17,477,710	0

PART II

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

Market for Registrant's Common Equity.

Our Common Stock is listed on the New York Stock Exchange under the symbol "BBG".

The range of high and low sales prices for our Common Stock for the period from December 10, 2004 when trading of our Common Stock commenced on the New York Stock Exchange through December 31, 2004, as reported by the NYSE, is as follows:

	Common Stock	
	High	Low
December 10, 2004—December 31, 2004	$ 35.00	$ 27.49

On March 1, 2005, the closing sales price for the Common Stock as reported by the NYSE was $30.73 per share.

Holders. On March 1, 2005, the number of holders of record of common stock was 209.

Dividends. We have not paid any cash dividends since our inception. We anticipate that all earnings will be retained for the development of our business and that no cash dividends will be paid on our Common Stock in the foreseeable future.

Use of Proceeds. On December 9, 2004, our Registration Statements on Form S-1 (SEC File Nos. 333-114554, 333-121128 and 333-121142) concerning our initial public offering were declared effective by the SEC. The offering was completed on December 15, 2004 and the underwriters purchased a total of 14,950,000 shares of our common stock at a price to public of $25.00 per share, for aggregate proceeds, before underwriting discounts, of $373.8 million. Goldman, Sachs & Co., J.P. Morgan Securities Inc. and Lehman Brothers Inc. were the representatives of the underwriters. We paid total underwriting discounts and commissions of $23.2 million, net of a $1.1 million credit received for early re-payment of the bridge loan, and total other expenses of $3.3 million in connection with our initial public offering, which resulted in our receiving net offering proceeds of approximately $347.3 million. The underwriting discounts and commissions included approximately $10.4 million paid to Goldman, Sachs & Co., whose related entities own more than 10% of our Common Stock. None of the other payments were to officers, directors or their associates, 10% stockholders or affiliates of the Company.

We used $149.3 million of the net proceeds of our initial public to repay the entire $150 million principal amount, net of refunds of certain fees, and accrued interest outstanding under our senior subordinated credit and guaranty agreement, or "bridge loan", and $123.2 million, including accrued interest, to repay the entire outstanding indebtedness under our revolving credit facility. The additional proceeds of approximately $77.1 million will be used to fund general corporate purposes, including exploration and development activities, oil and gas reserve and leasehold acquisitions in the ordinary course of business, working capital and other general corporate purposes. The bridge loan was made to the Company by, and the repayment of the bridge loan was made to, an affiliate of Goldman, Sachs & Co. An affiliate of J.P. Morgan Securities Inc. serves as sole lead arranger on our revolving credit facility. Entities related to each of Goldman, Sachs & Co. and J.P. Morgan Securities Inc. own more than 10% or our Common Stock. See, "Item 13. Certain Relationships and Related Transactions". None of the other payments were to officers, directors or their associates, 10% stockholders or affiliates of the Company.

Item 6. Selected Financial Data

The following table presents selected historical financial data of the Company for the period from January 7, 2002 (inception) through December 31, 2002 and the years ended December 31, 2003 and 2004. All share and per share amounts for all periods presented have been restated to reflect the 1-for-4.658 reverse stock split which was effected upon completion of our IPO. Future results may differ substantially from historical results because of changes in oil and gas prices, production increases or declines and other factors. This information should be read in conjunction with the financial statements and notes thereto and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations", presented elsewhere in this Annual Report on Form 10-K.

Selected Historical Information for Bill Barrett Corporation

The consolidated income statement information for the period from January 7, 2002 (inception) through December 31, 2002 and for the years ended December 31, 2003 and 2004 and the balance sheet information as of December 31, 2003 and 2004 are derived from our audited financial statements included elsewhere in this report. The balance sheet information at December 31, 2002 is derived from audited financial statements that are not included in this report.

	Period from January 7, 2002 (inception) through December 31, 2002	Year Ended December 31, 2003	Year Ended December 31, 2004
	(in thousands, except per share data)		
Statement of Operations Data:			
Production revenues (1)	$ 16,007	$ 75,252	$ 165,843
Other revenues	74	184	4,137
Operating expenses:			
Lease operating expense	2,231	8,462	14,592
Gathering and transportation expense	229	3,646	5,968
Production tax expense	2,021	9,815	20,087
Exploration expense	1,592	6,134	36,156
Impairment expense	—	1,795	516
Depreciation, depletion and Amortization	9,162	30,724	68,202
General and administrative	5,476	14,213	18,061
Non-cash stock-based compensation expense	1,322	3,637	3,031
Total operating expenses	22,033	78,426	166,613

Operating (loss) income	(5,952)	(2,990)	3,367
Other income (expenses):			
Interest income	303	123	437
Interest expense	(65)	(1,431)	(9,945)
Loss on sale of securities	(1,465)	—	—
Total other expense	(1,227)	(1,308)	(9,508)
Loss before income taxes	(7,179)	(4,298)	(6,141)
Benefit from income taxes	2,164	320	875
Loss from continuing operations	(5,015)	(3,978)	(5,266)
Income from discontinued operations (net of taxes)	27	—	—
Net loss	(4,988)	(3,978)	(5,266)
Less deemed dividends on preferred stock	—	—	(36,343)
Less cumulative dividends on preferred stock	(4,430)	(12,682)	(18,633)
Net loss attributable to common stockholders	$ (9,418)	$ (16,660)	$ (60,242)
Loss per common share(2):			
Basic and Diluted	$ (18.02)	$ (19.38)	$ (15.40)
Weighted average number of common shares outstanding (3)	522.7	859.4	3,912.3

	Period from January 7, 2002 (inception) through December 31, 2002	Year Ended December 31, 2003	Year Ended December 31, 2004
		(in thousands)	
Selected Cash Flow and Other Financial Data:			
Net loss	$ (4,988)	$ (3,978)	$ (5,266)
Depreciation, depletion and amortization	9,162	30,724	68,202
Other non-cash items	672	7,786	26,887
Change in current assets and liabilities	(967)	(659)	(2,941)
Net cash provided by operating activities	$ 3,879	$ 33,873	$ 86,882
Capital expenditures(4)	$ 166,893	$ 186,327	$ 347,099(5)

(1) Revenues are net of effects of hedging transactions.

(2) All per share information has been adjusted to reflect the 1-for-4.658 reverse common stock split effected upon the completion of our IPO.

(3) The weighted average number of common shares outstanding used in the loss per share calculation are computed pursuant to Statement of Financial Accounting Standards ("SFAS") No. 128 *Earnings Per Share.* The weighted average common shares outstanding does not include the 6,594,725 Series A or the 51,951,418 Series B preferred stock that were converted into a total of 26,387,679 common shares until the completion of our IPO in December 2004.

(4) Excludes future reclamation liability accruals of $1.0 million, $2.9 million, and $7.1 million in 2002, 2003 and 2004, respectively, and includes exploration cost expensed under successful efforts accounting of $1.6 million, $6.1 million, and $36.2 million in 2002, 2003, and 2004, respectively. Also includes furniture, fixtures and equipment costs of $1.1 million in 2002, $1.8 million in 2003, and $2.1 million in 2004.

(5) Includes $137.3 million to acquire properties in the Piceance Basin in September 2004, and excludes $8.8 million in divestitures during the year ended December 31, 2004.

	As of December 31,		
	2002	2003 (in thousands)	2004
Balance Sheet Data:			
Cash and cash equivalents	$ 5,713	$ 16,034	$ 99,926
Other current assets	7,246	19,613	37,964
Oil and natural gas properties, net of accumulated depreciation, depletion and amortization	156,372	307,920	549,690
Other property and equipment, net of depreciation	896	1,539	2,475
Other assets	2,465	2,663	6,103
Total assets	$ 172,692	$ 347,769	$ 696,158
Current liabilities	$ 10,873	$ 46,156	$ 62,106
Long-term debt	36,900	58,900	-
Other long-term liabilities	1,117	4,387	14,320
Stockholders' equity	123,802	238,326	619,732
Total liabilities and stockholders' Equity	$ 172,692	$ 347,769	$ 696,158

Selected Historical Financial and Operating Information for Wind River Acquisition Properties

The selected financial data for the Wind River Acquisition Properties for the years ended December 31, 2000 and 2001 and for the period from January 1, 2002 through March 28, 2002 were derived from the audited and unaudited financial statements concerning the Wind River Acquisition Properties not included in this report and information provided by the seller. We requested that the seller provide us with all available information concerning these properties. Because these properties were a small portion of the seller's total assets, the seller did not have more detailed financial information regarding these properties. For additional information concerning our financial data, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations".

	2000	2001 (in thousands)	Period from January 1, 2002 through March 28, 2002
Statement of Operations Data:			
Operating revenues	$ 73,083	$ 55,380	$ 4,605
Direct operating expenses:			
Lease operating expense	2,132	2,672	551
Gathering and transportation expense	72	33	7
Production tax expense	8,871	6,875	644
Total direct operating expenses	$ 11,075	$ 9,580	$ 1,202
Revenues in excess of direct operating expenses	$ 62,008	$ 45,800	$ 3,403
Summary Production Data:			
Production Data:			
Natural gas (MMcf)	20,679	12,588	2,166
Oil (MBbls)	66	40	5
Combined (MMcfe)	21,075	12,828	2,196
Average Prices:			
Natural gas (per Mcf)	$ 3.48	$ 4.32	$ 2.08
Oil (per Bbl)	27.76	24.10	18.40
Combined (per Mcfe)	3.47	4.32	2.10
Selected Cash Flow Data:			
Operating Activities:			
Revenues in excess of direct operating expenses	$ 62,008	$ 45,800	$ 3,403
Change in current assets and liabilities			
Accounts receivable	(3,187)	5,955	538
Accounts payable	106	(35)	(88)
Production taxes payable	2,034	(1,469)	388
Investing Activities:			
Additions to oil and gas properties	$ (31,391)	$ (7,925)	$ (718)

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

Introduction

The following discussion and analysis should be read in conjunction with the "Selected Financial Data" and the accompanying financial statements and related notes included elsewhere herein. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for natural gas and oil, economic and competitive conditions, regulatory changes, estimates of proved reserves, potential failure to achieve production from development projects, capital expenditures and other uncertainties, as well as those factors discussed below and elsewhere in this Annual Report on Form 10-K, particularly in "Risk Factors" and "Cautionary Note Regarding Forward-Looking Statements", subsections of this "Management's Discussion and Analysis of Financial Condition and Results of Operations" section, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

Overview

We explore for and develop oil and natural gas in the Rocky Mountain region of the United States. On December 9, 2004, our Registration Statements on Form S-1 (SEC File Nos. 333-114554, 333-121128 and 333-121142) concerning our initial public offering ("IPO") were declared effective by the SEC. The offering was completed on December 15, 2004 and the underwriters purchased a total of 14,950,000 shares of our common stock at a price to the public of $25.00 per share. We received net proceeds of $347 million after deducting underwriting fees and other offering costs.

We intend to increase stockholder value by profitably growing reserves and production, primarily through drilling operations. We seek high quality exploration and development projects with potential for providing long-term drilling inventories that generate high returns. We recently decided to enter into joint exploration agreements with industry partners to whom we plan to sell portions of our interests in several exploratory projects to recoup a portion of our investment, to reduce the risk of exploratory drilling and to expedite drilling across our exploration inventory. We currently plan to use the proceeds from the selldowns to increase planned exploration activities and capital expenditures. Substantially all of our revenues are generated through the sale of natural gas and oil production under either short-term contracts or spot gas purchase contracts at market prices. Approximately 92% of our December 2004 production was natural gas.

Our company was formed in January 2002. We began active natural gas and oil operations in March 2002 upon the acquisition of properties in the Wind River Basin. We acquired these properties from a subsidiary of the Williams Companies, which acquired these properties in connection with the Williams Companies' acquisition of Barrett Resources Corporation in August 2001. Since inception, we substantially increased our activity level and the number of properties that we operate. Our operating results reflect this growth. Also in 2002, we completed two additional acquisitions of properties in the Uinta, Wind River, Powder River and Williston Basins. In early 2003, we completed an acquisition of largely undeveloped coalbed methane properties located in the Powder River Basin. In September 2004, we acquired properties in the Piceance Basin consisting of 8,537 net developed and 9,044 net undeveloped lease acres, and 79 net producing wells in or around the Gibson Gulch field (the "Piceance Basin Acquisition Properties"). A summary of our significant property acquisitions is as follows:

Primary Locations of Acquired Properties	Date Acquired	Purchase Price (in millions)
Wind River Basin	March 2002	$ 74
Uinta Basin	April 2002	8
Wind River, Powder River and Williston Basins	December 2002	62
Powder River Basin	March 2003	35
Piceance Basin	September 2004	137

Because of our rapid growth through acquisitions and development of our properties, our historical results of operations and period-to-period comparisons of these results and certain financial data may not be meaningful or indicative of future results.

Our acquisitions were financed with a combination of funding from our private equity stock investments, our bank line of credit, cash flow from operations and, in the case of the Piceance Basin properties, a bridge loan that was repaid in December 2004 with a portion of the proceeds of our IPO. The March 2002 purchase of properties in the Wind River Basin included core properties in the Cave Gulch and Wallace Creek fields. The April 2002 acquisition in the Uinta Basin included the West Tavaputs project area. The December 2002 acquisition included the Cooper Reservoir field, properties in the Powder River Basin and oil properties in the Williston Basin, along with other properties that were not deemed core to our business operations (approximately 20% of the acquisition) and that were sold in 2003. The September 2004 acquisition included the Gibson Gulch field in the Piceance Basin. Our 2003 and 2004 activities include development drilling and exploration in each of these areas. Our activities are now focused on evaluating and developing our asset base, increasing our acreage positions, and evaluating potential acquisitions.

As of December 31, 2004, we had 292 Bcfe of estimated net proved reserves with a PV-10 of $592 million and a Standardized Measure of $466 million, while at December 31, 2003, we had 204 Bcfe of estimated net proved reserves with a PV-10 of $521 million and a Standardized Measure of $405 million, excluding properties held for sale.

The average sales prices received for natural gas in all our core areas rose sharply in 2003 and 2004 compared to 2002. Before the effect of hedging contracts, the average price we received for natural gas in 2003 was $4.51 per Mcf compared to $2.39 per Mcf in 2002. Before the effects of hedging contracts, the average price we received for oil was $28.85 per Bbl in 2003 compared to $25.39 per Bbl in 2002. Before the effect of hedging contracts, the average price we received for natural gas and oil in 2004 was $5.53 per Mcf and $39.49 per Bbl, respectively.

Higher oil and natural gas prices have led to higher demand for drilling rigs, operating personnel and field supplies and services, and have caused increases in the costs of those goods and services. To date, the higher sales prices for natural gas and oil have more than offset the higher field costs. Given the inherent volatility of oil and natural gas prices that are influenced by many factors beyond our control, we plan our activities and budget based on conservative sales price assumptions, which generally are lower than the average sales prices received in 2004. We focus our efforts on increasing natural gas reserves and production while controlling costs at a level that is appropriate for long-term operations. Our future earnings and cash flows are dependent on our ability to manage our overall cost structure to a level that allows for profitable production.

Like all oil and gas exploration and production companies, we face the challenge of natural production declines. As initial reservoir pressures are depleted, oil and gas production from a given well naturally decreases. Thus, an oil and gas exploration and production company depletes part of its asset base with each unit of oil or natural gas it produces. We attempt to overcome this natural decline by drilling to find additional reserves and acquiring more reserves than we produce. Our future growth will depend on our ability to continue to add reserves in excess of production. We will maintain our focus on costs to add reserves through drilling and acquisitions as well as the costs necessary to produce such reserves. Our ability to add reserves through drilling is dependent on our capital resources and can be limited by many factors, including our ability to timely obtain drilling permits and regulatory approvals. The permitting and approval process has been more difficult in recent years than in the past due to increased activism from environmental and other groups and has extended the time it takes us to receive permits and other necessary approvals. Because of our relatively small size and concentrated property base, we can be disproportionately disadvantaged by delays in obtaining or failing to obtain drilling approvals compared to companies with larger or more dispersed property bases. As a result, we are less able to shift drilling activities to areas where permitting may be easier and we have fewer properties over which to spread the costs related to complying with these regulations and the costs or foregone opportunities resulting from delays.

Results of Operations

The following table sets forth selected operating data for the periods indicated.

	Period from January 7, 2002 (inception) through December 31, 2002 (1)	Year Ended December 31, 2003	2002 to 2003 Increase (Decrease)		Year Ended December 31, 2004	2003 to 2004 Increase (Decrease)	
			Amount	Percent		Amount	Percent
Operating Results:			(in thousands)				
Revenues							
Oil and gas production	$16,007	$75,252	$59,245	370%	$165,843	$90,591	120%
Other income	74	184	110	149%	4,137	3,953	2,148%
Operating Expenses							
Lease operating expense	2,231	8,462	6,231	279%	14,592	6,130	72%
Gathering and transportation expense	229	3,646	3,417	1,492%	5,968	2,322	64%
Production tax expense	2,021	9,815	7,794	386%	20,087	10,272	105%
Exploration expense	1,592	6,134	4,542	285%	36,156	30,022	489%
Impairment expense	—	1,795	1,795	n/a	516	(1,279)	(71%)
Depreciation, depletion and amortization	9,162	30,724	21,562	235%	68,202	37,478	122%
General and administrative	5,476	14,213	8,737	160%	18,061	3,848	27%
Non-cash stock-based compensation expense	1,322	3,637	2,315	175%	3,031	(606)	(17%)
Total operating expenses	$22,033	$78,426	$56,393	256%	$166,613	$88,187	112%
Production Data:							
Natural gas (MMcf)	6,371	16,315	9,944	156%	28,864	12,549	77%
Oil (MBbls)	30	328	298	993%	474	146	45%
Combined volumes (MMcfe)	6,551	18,283	11,732	179%	31,708	13,426	73%
Daily combined volumes (Mmcfe/d)	24	50	27	112%	87	37	74%
Average Prices (2):							
Natural gas (per Mcf)	$2.39	$4.03	$1.64	69%	$5.10	$1.07	27%
Oil (per Bbl)	25.39	28.85	3.46	14%	39.49	10.64	37%
Combined (per Mcfe)	2.44	4.12	1.68	69%	5.23	1.11	27%
Average Costs (per Mcfe):							
Lease operating expense	$0.34	$0.46	$0.12	35%	$0.46	$0.00	0%
Gathering and transportation expense	0.03	0.20	0.17	567%	0.19	(0.01)	(5%)
Production tax expense	0.31	0.54	0.23	74%	0.63	0.09	17%
Depreciation, depletion and amortization	1.40	1.68	0.28	20%	2.15	0.47	28%
General and administrative	0.84	0.78	(0.06)	(7%)	0.57	(0.21)	(27%)

(1) In the period ended December 31, 2002, production commenced on March 29, 2002 following the purchase of our Wind River Acquisition Properties.

(2) Average prices shown in the table are net of the effects of hedging transactions. As a result of hedging transactions, natural gas and oil production revenues were reduced by $7.7 million and $12.4 million for the years ended December 31, 2003 and 2004, respectively. Three were no derivative contract settlements for the period from January 7, 2002 (inception) through December 31, 2002. Before the effect of hedging contracts, the average price we received for natural gas in 2004 was $5.53 per Mcf compared with $4.51 per Mcf in 2003 and $2.39 per Mcf in 2002.

Year Ended December 31, 2004 Compared to Year Ended December 31, 2003

Revenues. Production revenues increased from $75.3 million for the year ended December 31, 2003 to $165.8 million for the year ended December 31, 2004 due to both an increase in production and increases in natural gas and oil prices. Price increases added approximately $20.3 million of production revenues, and production increases from the development of existing properties, and to a lesser extent, the Piceance Basin Acquisition Properties, added approximately $70.2 million of production revenues. Significant decreases in product prices would significantly reduce our revenues from existing properties. See "— Quantitative and Qualitative Disclosure about Market Risk". Other revenues totaled $4.1 million for the year ended December 31, 2004, which were principally gains on disposals of oil and gas properties.

Total production volumes for the 2004 calendar year increased 74% from 2003 with increases in all major producing basins. Additional information concerning production is in the following table.

	Year Ended December 31,			
	2003 (1)		2004	
	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
Wind River Basin	71	12,513	107	17,676
Uinta Basin	2	1,355	6	5,295
Powder River Basin	—	2,114	—	4,934
Williston Basin	216	197	329	162
Piceance Basin	—	—	5	779
Other	39	136	27	18
Total	328	16,315	474	28,864

(1) Excludes volumes produced related to properties held for sale.

The production increase in the Wind River Basin is due to development in our Cave Gulch and Cooper Reservoir fields that occurred throughout 2003 and 2004. The production increase in the Uinta Basin is due to development activities in both the West Tavaputs and Hill Creek areas. The production increase in the Powder River Basin reflects the acquisition made in March 2003 along with an active development program that commenced in the middle of 2003 and continued through 2004. The production increase in the Williston Basin is principally due to continued development activities on the properties that were acquired in December 2002.

Hedging Activities. In 2004 we hedged approximately 38% of our natural gas volumes, which resulted in a reduction in revenues of $12.4 million. No oil volumes were hedged in 2004. In 2003 we hedged approximately 45% of our natural gas volumes, incurring a reduction in revenues of $7.7 million, and in 2003 we hedged approximately 38% of our oil volumes, resulting in an immaterial increase to revenues.

Lease Operating Expense and Gathering and Transportation Expense. Our lease operating expense remained flat at $0.46 per Mcfe in 2004 and 2003 while our gathering and transportation expense decreased from $0.20 per Mcfe in 2003 to $0.19 per Mcfe in 2004. The decrease in gathering and transportation expense was primarily a result of using company owned gathering lines to transport gas in the Wallace Creek field in 2004 instead of outside party facilities that were used in 2003.

Production Tax Expense. Total production taxes increased from $9.8 million in 2003 to $20.1 million in 2004 as a result of higher production revenues which increased primarily due to higher prices received and higher volumes produced in 2004 compared to 2003. Production taxes as a percentage of natural gas and oil sales before hedging adjustments remained relatively flat at 11.3% in 2004 and 11.8% in 2003. Production taxes are primarily based on the wellhead values of production and tax rates that vary across the different areas that we operate. As the ratio of our production changes from area to area, our production rate will either increase or decrease depending on the quantities produced from each area and the production tax rates in effect in each individual area. For example, we intend to develop our acreage position on Indian Tribal lands in the state of Utah where the combined production tax rate for the state and the Indian Tribe will approximate 15%. This production tax rate is higher than our current overall rate. In the event our development efforts are successful, our overall production tax rate will increase relative to the level of our success on the Indian Tribal lands in Utah .

Exploration Expense. Exploration expense increased from $6.1 million in 2003 to $36.2 million in 2004. The costs in the 2003 period include $3.0 million for seismic programs principally in the Wind River, DJ and Uinta Basins, $2.2 million for exploratory dry hole costs in the Powder River and Uinta Basins and $0.9 million for delay rentals, nonproducing leasehold abandonments and other costs. The costs in 2004 include $11.3 million for seismic programs primarily in the DJ, Wind River and Uinta Basins, $23.0 million for exploratory dry hole costs primarily in the Wind River (including our Pommard #1 well determined to be a dry hole in December 2004 with a dry hole cost expensed in 2004 of $7.9 million) and Uinta Basins and $1.9 million for delay rentals, nonproducing leasehold abandonments and other costs. We account for oil and gas exploration and production activities using the successful efforts method under which we capitalize exploratory well costs until a determination is made as to whether or not the wells have found proved reserves. Generally, if proved reserves are not assigned to an exploratory well within one year following completion of drilling, the costs of drilling the well are charged to expense, otherwise, the costs remain capitalized and are depleted as production occurs. The following table shows the costs of exploratory wells for which drilling was completed and which are included in unevaluated oil and gas properties as of December 31, 2004 pending determination of whether the wells will be assigned proved reserves. The following table does not include $4.1 million related to exploratory wells in progress for which drilling had not been completed at December 31, 2004:

	Time Elapsed Since Drilling Completed				
	0-3 Months	4-6 Months	7-12 Months	>12 Months	Total
			(in thousands)		
Wells for which drilling has completed	$10,105	$5,158	$570	$—	$15,833

Impairment Expense. Impairment expense decreased from $1.8 million in 2003 to $0.5 million in 2004. In 2003 the impairment expense reflected a write-down to fair value of undeveloped leasehold costs in southern Montana, whereas the impairment expense in 2004 reflected a write-down to estimated fair value of the producing Talon Field in Wyoming's Wind River Basin based on proved reserves on December 31, 2004. We periodically assess our undeveloped leasehold costs pursuant to Statement of Accounting Standards ("SFAS") No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies*, to determine whether or not the carrying amount has been impaired. In 2003 the carrying amount of undeveloped leasehold costs in southern Montana exceeded fair value, determined by bids we received from independent third parties to purchase the acreage, and accordingly, we recorded an impairment expense equal to the excess of carrying amount over fair value. We assess our producing properties on a field-by-field basis for recoverability whenever events or changes in circumstances indicate carrying amounts may not be recoverable pursuant to SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. Under SFAS No. 144 an impairment loss is recognized if the carrying amount of a long-lived asset is not recoverable and exceeds its fair value. The carrying amount is not recoverable if it exceeds the sum of its estimated undiscounted cash flows, and an impairment loss is measured as the amount by which the carrying amount exceeds its fair value. At December 31, 2004, we determined the estimated fair value of the Talon Field to be equal to the present value, discounted at 10%, of the future cash flows from the field as computed by our reservoir engineers and reviewed by independent reservoir engineers. The carrying amount of the evaluated properties in the Talon Field exceeded the estimated fair value by $0.5 million, the amount of which we recorded as an impairment expense in 2004.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense was $68.2 million in 2004 compared to $30.7 million in 2003. $21.9 million of the increase was due to the 73% increase in production and $15.5 million was due to an increased depletion rate for 2004. In 2003 the weighted average depletion rate was $1.63 per Mcfe compared to $2.12 per Mcfe in 2004. Under successful efforts accounting, depletion expense is separately computed for each producing area. The capital expenditures for proved properties for each area compared to the proved reserves corresponding to each producing area determine a depletion rate for current production. In 2004 the relationship of capital expenditures, proved reserves and production from certain producing areas yielded a higher depletion rate than 2003. Future depletion rates will be adjusted to reflect future capital expenditures and proved reserve changes in specific areas.

General and Administrative Expense. General and administrative expense increased $3.9 million from $14.2 million in 2003 to $18.1 million in 2004. This increase was primarily due to increased personnel required for our capital program and production levels. As of December 31, 2004, we had 140 full-time employees compared to 95 as of December 31, 2003. On a per unit produced basis, general and administrative expense decreased from $0.78 per Mcfe in 2003 to $0.57 per Mcfe in 2004 as production increased at a greater rate than our general and administrative expenses. At our stage of investment activity compared to our production level, a significant portion of our general and administrative expense consists of the personnel and related costs to prudently manage our capital expenditure program. As our capital expenditure program causes an increase in our production levels, we expect that general and administrative expense per unit of production will continue to decrease.

Non-cash Stock-based Compensation Expense. Non-cash stock-based compensation expense decreased $0.6 million from $3.6 million in 2003 to $3.0 million in 2004. Non-cash stock-based compensation for 2003 and 2004 is related to the vesting of the restricted common stock issued to management and employees upon formation of the Company, our stock option plans and purchases by employees of Series B convertible preferred stock at less than estimated fair market value. The decrease in expense was due principally to the 2004 and 2003 vesting events related to our restricted common stock and stock options. The components of non-cash stock-based compensation for 2003 and 2004 are shown in the following table.

	Year Ended December 31,	
	2003	2004
	(in thousands)	
Restricted common stock	$2,640	$2,044
Stock Options	565	705
Employee purchases of Series B convertible preferred stock	432	282
Total	$3,637	$3,031

Restricted common stock was subject to dual vesting provisions of: (1) one share vesting for every $141.62355 received from investors in Series B Preferred Stock ("dollar vesting"), and (2) 20% vesting upon purchase and an additional 20% vesting each year for four years after purchase ("time vesting"). These restricted shares vest at the later to occur of time vesting and dollar vesting. At December 31, 2004, the restricted common stock was 100% dollar vested and 78.3% time vested. As a result of being 100% dollar vested, no additional stock-based deferred compensation on restricted common stock will be incurred, however, at December 31, 2004, a balance of $0.5 million of deferred compensation remained to be amortized into non-cash stock-based compensation expense through January 2006 as a result of time vesting.

Interest Expense. Interest expense increased $8.5 million to $9.9 million in 2004 compared to 2003. The increase was due to higher debt levels in 2004 to fund acquisitions and development activities. The weighted average outstanding balance under our credit facility was $73.7 million for 2004 as compared to $39.8 million for 2003. In addition to borrowings under our credit facility, we borrowed $150 million under a bridge loan on September 1, 2004 to fund the acquisition of our Piceance Basin properties. The bridge loan, as well as the outstanding balance of our credit facility, was repaid in full in December 2004 with proceeds from our IPO. Total interest expense in 2004 under the bridge loan was $6.3 million comprised of fees of $3.7 million and interest charges of $2.6 million. To date, no interest has been capitalized.

Income Tax Expense. Our effective tax rate was 7% in 2003 and 14% in 2004. Our effective tax rate for 2003 and 2004 differs from the statutory rates primarily because of the amount of stock-based compensation expense recorded for financial statement purposes that is a permanent difference and will not be deducted for tax purposes. All of our income tax benefit and provisions to date are deferred. Due to the net operating loss carryforward and tax deductions being created by our drilling activities, we expect that we will not incur cash tax liabilities for at least the next year. Our estimates of future taxable income, including potential elections to capitalize all intangible drilling costs and reversals of deferred tax liabilities, are considerable such that management has determined that the net deferred tax assets will be realized, and therefore no valuation allowance has been provided.

Net Income (Loss). We generated a net loss of $5.3 million in 2004 compared to a net loss of $4.0 million in 2003. The reason for the increase in net loss was principally the significant increase in exploration expense offset by an increase in production volumes and product prices, net of operating costs.

Year Ended December 31, 2003 Compared to the Period from January 7, 2002 (inception) through December 31, 2002

Revenues. Production revenues increased from $16.0 million in 2002 to $75.3 million in 2003 due to both an increase in production and increases in natural gas and oil prices. Price increases added approximately $10.5 million of production revenues, production from properties acquired in 2003 added approximately $6.7 million of revenues and production increases from the development of existing properties added approximately $42.1 million of production revenues, net of natural production declines. Significant decreases in product prices would significantly reduce our revenues from existing properties. See "— Quantitative and Qualitative Disclosure about Market Risk".

Production volumes in 2003 increased 179% from 2002 levels with increases in all producing basins. Additional information concerning production is in the following table.

	Period from January 7, 2002 (inception) through December 31, 2002 (1)(2)		Year Ended December 31, 2003 (1)	
	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
Wind River Basin	23	6,090	71	12,512
Uinta Basin	—	259	2	1,355
Powder River Basin	—	14	—	2,114
Williston Basin	7	8	216	197
Other	—	—	39	137
Total	30	6,371	328	16,315

(1) Excludes volumes produced related to properties held for sale.

(2) In the period ended December 31, 2002, production commenced on March 29, 2002 following the purchase of our Wind River Acquisition Properties.

The production increase in the Wind River Basin is due to development in our Cave Gulch field that occurred throughout 2002 and 2003, the acquisition of the Cooper Reservoir field in December 2002 and the subsequent 2003 development of properties included in the Cooper Reservoir acquisition. The production increase in the Uinta Basin is due to development activities in both the West Tavaputs and Hill Creek areas. The production increase in the Powder River Basin reflects the two acquisitions made in December 2002 and March 2003 along with an active development program that occurred principally during the last six months of 2003. The production increase in the Williston Basin is principally due to a full year of production from the properties that were acquired in December 2002.

Hedging Activities. During 2003, we hedged 48% of our natural gas volumes, incurring a reduction from realized prices of $7.7 million, and 37% of our oil volumes resulting in an immaterial addition to realized prices. During 2002, we did not hedge any of our natural gas or oil volumes.

Lease Operating Expense and Gathering and Transportation Expense. Our lease operating expense increased from $0.34 per Mcfe in 2002 to $0.46 per Mcfe in 2003, while our gathering and transportation expense increased from an insignificant amount in 2002 to $0.20 per Mcfe in 2003. The increase is due to a higher proportion of our production being in areas with higher operating costs. In 2002, substantially all of our production was in the Wind River Basin. During 2003, we increased our production in the Uinta, Powder River and Williston Basins, all of which are higher operating and gathering cost areas than the areas we were producing from during most of 2002.

Production Tax Expense. Production taxes as a percentage of natural gas and oil sales before hedging adjustments were 12.6% in 2002 and 11.8% in 2003. Production taxes are primarily based on the wellhead values of production and vary across the different areas that we operate. Production tax expense increased as a result of higher production revenues, primarily due to increased production and higher prices in 2003.

Exploration Expense. Exploration expense increased $4.5 million to $6.1 million in 2003. The 2002 costs are primarily seismic programs in the Wind River and Uinta Basins. The 2003 costs include $3.1 million for seismic programs in the Wind River, the Uinta and DJ Basins. The 2003 exploration costs also include $1.9 million for environmental assessment work and monitoring wells related to the coalbed methane project on the Crow Indian reservation in southern Montana that was terminated in March 2004. Delay rentals and other miscellaneous exploration expenses were $1.1 million in 2003.

Impairment Expense. During 2003, we recorded a $1.8 million impairment for undeveloped leases in southern Montana to reduce the book value to estimated market value. We periodically assess our undeveloped leasehold costs pursuant to SFAS No. 19 to determine whether or not the carrying amount has been impaired. In 2003 the carrying amount of undeveloped leasehold costs in southern Montana exceeded fair value, determined by bids we received from independent third parties to purchase the acreage, and accordingly, we recorded an impairment expense equal to the excess of carrying amount over fair value.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense was $30.7 million in 2003 compared to $9.2 million in 2002. $16.3 million of the increase is due to the 179% increase in production and $5.1 million is due to an increased depletion rate for the 2003 production. During 2002, the weighted average depletion rate was $1.40 per Mcfe. In 2003, the weighted average depletion rate was $1.68 per Mcfe. Under successful efforts accounting, depletion expense is separately computed for each producing area. The capital expenditures for proved properties for each area compared to the proved reserves corresponding to each producing area determine a depletion rate for current production. During 2003, the relationship of capital expenditures, proved reserves and production from certain producing areas yielded a higher depletion rate than 2002. Future depletion rates will be adjusted to reflect future capital expenditures and proved reserve changes to be applied to production from specific areas.

General and Administrative Expense. General and administrative expense increased $8.7 million from $5.5 million in 2002 to $14.2 million in 2003. This increase was primarily due to increased personnel required for our capital program and production levels. At our stage of activity compared to our production level, a significant portion of our general and administrative expense consists of the personnel and related costs to prudently manage our capital expenditure program.

Non-cash Stock-based Compensation Expense. Non-cash stock-based compensation expense increased $2.3 million from $1.3 million in 2002 to $3.6 million in 2003. The increase in expense was due to the increased value of our common stock in 2003 (estimated fair value of $7.56 per share on December 31, 2003) compared to 2002 (estimated fair value of $2.94 per share on December 31, 2002) and the vesting events with respect to our restricted common stock and stock options that occurred in each year. See "— Critical Accounting Policies and Estimates — Stock-based Compensation".

Interest Expense. Interest expense increased $1.3 million to $1.4 million in 2003. The increase was due to higher debt levels in 2003 to fund acquisitions and development activities. We initially borrowed $35 million in December 2002 to partially finance an acquisition of properties. During 2003, we used a combination of debt, equity and cash flow from operations to fund our activities, and ended the year with an outstanding balance on our bank line of credit of $57 million. The weighted average level of debt outstanding during 2003 was $39.8 million.

Other Expense. Other expense of $1.5 million in 2002 is due to a loss on the sale of marketable securities. These securities were received in payment of a portion of the purchase price for Series A preferred stock in March 2002. All these securities were sold in 2002.

Income Tax Expense. Our effective tax rate was 30% in 2002 and 7% in 2003. Our effective tax rate differs from the statutory rates primarily because of the amount of stock-based compensation expense recorded in the financial statements that will not be deductible for tax purposes. All of our income tax benefit is deferred.

Income from Discontinued Operations. In 2002, we generated $27,000 of income from discontinued operations from properties acquired in December 2002. These properties were sold in 2003 at amounts that approximated the assigned value of the properties.

Net Loss. Our net loss decreased from $5.0 million in 2002 to $4.0 million in 2003. The primary reasons for the improved results were the increase in production volumes and product prices, net of operating costs, offset by the increased depreciation, depletion and amortization, exploration and impairment expenses.

Capital Resources and Liquidity

Our primary sources of liquidity since our formation in January 2002 have been from sales and other issuances of securities, net cash provided by operating activities, a bank line of credit and a bridge loan to finance our September 2004 acquisition of properties in the Piceance Basin. Our primary use of capital has been for the acquisition, development, and exploration of oil and natural gas properties. As we pursue growth, we continually monitor the capital resources available to us to meet our future financial obligations, planned capital expenditure activities and liquidity. Our future success in growing proved reserves and production will be highly dependent on capital resources available to us and our success in finding or acquiring additional reserves. We actively review acquisition opportunities on an ongoing basis. If we were to make significant additional acquisitions for cash, we may need to obtain additional equity or debt financing.

At December 31, 2004 our balance sheet reflected a cash balance of $99.9 million with no balance outstanding on our credit facility, principally as a result of completing our IPO on December 15, 2004 from which we received net proceeds of $347 million. On that date we repaid the $150 million bridge loan and paid down the outstanding balance of $123.2 million on our line of credit.

Cash Flow from Operating Activities

Net cash provided by operating activities was $3.9 million, $33.9 million and $86.9 million in 2002, 2003 and 2004, respectively. The increases in net cash provided by operating activities was substantially due to increased production revenues, partially offset by increased expenses, as discussed above in "— Results of Operations". Changes in current assets and liabilities reduced cash flow from operations by $1.0 million, $0.7 million and $2.9 million in 2002, 2003 and 2004, respectively.

Our operating cash flow is sensitive to many variables, the most significant of which is the volatility of prices for natural gas and oil produced. Prices for these commodities are determined primarily by prevailing market conditions. Regional and worldwide economic activity, weather and other substantially variable factors influence market conditions for these products. These factors are beyond our control and are difficult to predict.

To mitigate some of the potential negative impact on cash flow caused by changes in natural gas and oil prices and to comply with our credit agreement, we have entered into commodity swap and collar contracts to receive fixed prices for a portion of our natural gas and oil production. At December 31, 2004, we had in place natural gas and crude oil swap contracts and collars covering portions of our 2005 and 2006 production. Between January 1, 2005 and February 28, 2005, we entered into additional cash flow hedges for portions of 2005 and 2006 production. Our company's natural gas and oil derivative financial instruments have been designated as cash flow hedges in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* and are classified as either current or non current liabilities in our Consolidated Balance Sheets based on scheduled delivery of the underlying production.

The table below provides the volumes associated with the swap contracts as of March 1, 2005.

Product	Average Volume Per Day	Quantity Type	Fixed Price	Index Price (1)	Contract Period
Natural gas	10,000	MMBtu	$ 5.05	NORRM	1/1/2005-12/31/2005
Natural gas	10,000	MMBtu	5.27	NORRM	1/1/2005-12/31/2005
Oil	100	Bbls	32.96	WTI	1/1/2005-12/31/2005
Oil	100	Bbls	34.05	WTI	1/1/2005-12/31/2005
Oil	100	Bbls	36.12	WTI	1/1/2005-12/31/2005
Oil	100	Bbls	36.00	WTI	1/1/2005-12/31/2005

The table below provides the volumes associated with the collar contracts as of March 1, 2005.

Product	Average Volume Per Day	Quantity Type	Floor-Ceiling Pricing	Index Price (1)	Contract Period
Natural gas	10,000	MMBtu	$4.75-7.00	NORRM	1/1/2005-12/31/2005
Natural gas	5,000	MMBtu	4.75-6.75	NORRM	1/1/2005-12/31/2005
Natural gas	10,000	MMBtu	4.75-7.10	NORRM	1/1/2005-12/31/2005
Natural gas	5,000	MMBtu	5.00-6.46	CIGRM	4/1/2005-10/31/2005
Oil	400	Bbls	45.00-55.25	WTI	4/1/2005-12/31/2005
Natural gas	5,000	MMBtu	$4.75-6.05	NORRM	1/1/2006-12/31/2006
Natural gas	5,000	MMBtu	4.75-6.18	NORRM	1/1/2006-12/31/2006
Natural gas	15,000	MMBtu	4.75-6.21	NORRM	1/1/2006-12/31/2006
Natural gas	10,000	MMBtu	5.00-8.10	NORRM	1/1/2006-12/31/2006
Oil	700	Bbls	42.00-50.20	WTI	1/1/2006-12/31/2006

(1) NORRM refers to Northwest Pipeline Rocky Mountains price and CIGRM refers to Colorado Interstate Gas Rocky Mountains price as quoted in Platt's for Inside FERC on the first business day of each month. WTI refers to the West Texas Intermediate price as quoted on the New York Mercantile Exchange. See "— Quantitative and Qualitative Disclosure about Market Risk".

By removing the price volatility from a portion of our natural gas and oil production for 2005 and 2006, we have mitigated, but not eliminated, the potential effects of changing prices on our operating cash flow for those periods. While mitigating negative effects of falling commodity prices, these derivative contracts also limit the benefits we would receive from increases in commodity prices. It is our policy to enter into derivative contracts only with counterparties that are creditworthy major financial institutions deemed by management as competent and competitive market makers.

Based on hedging contracts outstanding on December 31, 2004, our cash flow hedge positions from natural gas and oil derivatives had an estimated net pre-tax liability of $5.7 million recorded as both current and non-current liabilities, as appropriate. We anticipate reclassifying this amount to gains or losses included in oil and gas production operating revenues as the hedged production quantity is produced. Based on current prices, the net amount of existing unrealized after-tax loss as of December 31, 2004 to be reclassified from accumulated other comprehensive income to oil and gas production operating revenues in the next twelve months would be $2.5 million. We anticipate that all original forecasted transactions will occur by the end of the originally specified time periods.

Capital Expenditures

Our capital expenditures were $347.1 million in 2004 and $186.3 million in 2003. The total for 2004 includes $152.4 million for acquisitions of properties, $156.4 million for drilling, development, exploration and exploitation (including related gathering and facilities, but excluding exploratory dry holes) of natural gas and oil properties, $36.2 million related to geologic and geophysical costs and exploratory dry holes, which are expensed under successful efforts accounting as exploration expense, and $2.1 million for furniture, fixtures and equipment. During the year ended December 31, 2004, we participated in the drilling of 285 gross wells and, during the year ended December 31, 2003, we participated in the drilling of 180 gross wells. The total capital expenditures for 2003 includes $49.0 million for the acquisition of properties, including $35.4 million for Powder River Basin properties acquired in March 2003, $129.4 million for drilling, development and exploration of natural gas and oil properties, $6.1 million for geologic and geophysical costs, and $1.8 million for furniture, fixtures and equipment. In 2002, our capital expenditures were $166.9 million, including $74 million for the March 2002 acquisition of properties in the Wind River Basin, $8.1 million for the April 2002 acquisition of properties in the Uinta Basin, and $61.5 million for the December 2002 acquisition of properties in the Wind River, Powder River and Williston Basins, including $12.1 million assigned to properties subsequently sold, $14.1 million for the drilling, development and exploration of natural gas and oil properties, $1.6 million for geologic and geophysical costs, and $1.1 million for furniture, fixtures and equipment.

Unevaluated properties increased $81.3 million, or 144%, to $137.6 million at December 31, 2004 from $56.3 million at December 31, 2003 principally as a result of our acquisition on September 1, 2004 of the Piceance Basin Acquisition Properties and increased development and exploratory drilling activity which resulted in an increase in capitalized costs of uncompleted wells in progress.

We currently anticipate our capital budget will be approximately $276 million for 2005. Of the $276 million capital budget, we plan to spend approximately $238 million (86%) in our development areas in Wyoming, Utah, Montana, North Dakota and Colorado, $36 million (13%) on exploration activities in Utah and Wyoming, with the remaining amounts allocated to other activities. Of the $238 million planned for expenditures in our development areas, approximately $46 million has been allocated to drill and complete proved undeveloped and proved nonproducing reserves. We are projecting that cash on hand, cash available from operating activities and borrowings from our credit facility will be sufficient to fund our 2005 capital budget. In addition to our 2005 capital budget, we plan to seek industry partners with whom we expect to enter into joint exploration agreements which would involve a sell down of approximately 30% to 60% of our working interest in a number of exploration projects principally in Wyoming, Montana and North Dakota. Proceeds from the selldowns will be used to accelerate and drill additional exploration wells not reflected in the 2005 capital budget.

The amount and timing of capital expenditures is largely discretionary and within our control. If oil and natural gas prices decline to levels below our acceptable levels, we could choose to defer a portion of these planned 2005 capital expenditures until later periods to achieve the desired balance between sources and uses of liquidity by prioritizing capital projects to first focus on those that we believe will have the highest expected financial returns and ability to generate near term cash flow. We routinely monitor and adjust our capital expenditures in response to changes in prices, drilling and acquisition costs, industry conditions and internally generated cash flow. Matters outside our control that could affect the timing of our capital expenditures include obtaining required permits and approvals in a timely manner and the availability of rigs and crews. Based upon current oil and natural gas price expectations for 2005, we anticipate that our operating cash flow and available borrowing capacity under our credit facility will exceed our planned capital expenditures and other cash requirements for 2005. However, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices. There can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures.

Financing Activities

Sales and Issuances of Securities. During 2002, we raised $126.5 million, net of costs, from the sale of equity securities, during 2003 we raised $117.7 million, net of costs, from the sale of equity securities, and in 2004 we raised $381.1 million, net of costs, from the sale of equity securities. A summary of these transactions is as follows:

In 2002, we

- issued 1,800,548 shares of our common stock to our initial officers and employees for $0.4 million in January to fund our formation;

- received $27.5 million from the sale to members of management and other private investors in March of our Series A preferred stock and a mandatorily convertible note that converted into Series A preferred stock immediately preceding the closing of our IPO;

- entered into a stock purchase agreement with institutional investors for the purchase of up to $255 million of Series B preferred stock for $5.00 per share pursuant to capital calls from time to time. During 2002, these investors purchased 21.1 million shares of Series B preferred stock for a total of $105.5 million; and

- issued 119,904 shares of Series A preferred stock in July for $0.5 million of value as a portion of the consideration for our obligation under an exploration agreement. These shares subsequently were returned to us when the exploration agreement was terminated in March 2004.

In 2003, we

- issued 23.3 million shares of Series B preferred stock to the institutional investors for a total of $116.5 million pursuant to capital calls under the Series B preferred stock purchase agreement;

- issued 495,100 shares of Series B preferred stock to certain of our employees for $2.5 million; and

- issued 250,600 shares of Series B preferred stock at the rate of $5.00 per share as partial payment of the total purchase price for oil and natural gas properties.

In 2004, we

- issued 59,800 shares of Series B preferred stock as consideration for natural gas and oil properties valued at an estimated $0.3 million;

- issued 6,600,000 shares of Series B preferred stock to the institutional investors for $33 million under the stock purchase agreement. As a result of these sales, the institutional investors fulfilled their obligations to purchase $255 million of Series B preferred stock pursuant to the Series B preferred stock purchase agreement;

- issued 145,918 shares of Series B preferred stock to certain of our employees for $0.7 million; and

- completed our IPO whereby we:
  (1) effected a 1-for-4.658 reverse split of common stock immediately preceding the closing of our IPO;
  (2) converted a $1.9 million mandatorily convertible note into 455,635 shares of Series A convertible preferred stock immediately preceding the closing of our IPO;
  (3) converted the then outstanding 6,834,725 shares of Series A convertible preferred stock into 2,592,317 shares of common stock;
  (4) converted the outstanding 51,951,418 shares of Series B convertible preferred stock, plus $35.7 million of acccumulated 7% dividends, into 23,795,362 shares of common stock, and:
  (5) issued 14,950,000 shares of common stock to the public for $347 million, net of fees and costs.

As a result of both the Series A and B preferred stock being converted into common stock immediately preceding the closing of our IPO, upon completion of the IPO, common stock became the only class of stock issued and outstanding.

Credit Facility. Our current bank line of credit provides a borrowing base of $200 million. This credit facility was entered into on February 4, 2004 and has a maturity of February 4, 2007. The credit facility was amended on September 1, 2004. The credit facility bears interest, based on the borrowing base usage, at the applicable London Interbank Offered Rate, or LIBOR, plus applicable margins ranging from 1.25% to 3.75% or an alternate base rate, based upon the greater of the prime rate or the federal funds effective rate plus applicable margins ranging from 0% to 2.25%. We pay commitment fees ranging from 0.375% to 0.50% of the unused borrowing base. The credit facility is secured by natural gas and oil properties representing at least 85% of the value of our proved reserves and the pledge of all of the stock of our subsidiaries. The borrowing base includes a $45 million portion, referred to as the "Tranche B" portion, that allows the borrowing base to be greater than the typical borrowing base that would have been computed based on proved natural gas and oil reserves. The Tranche B portion of the borrowing base terminates on November 30, 2005. At December 31, 2004, there were no amounts outstanding under our revolving credit facility. On December 15, 2004, upon the completion of our IPO, we repaid the then outstanding balance of $123 million. None of the outstanding borrowings at the time of repayment were under the Tranche B portion of the borrowing base. For information concerning the effect of changes in interest rates on interest payments under this facility, see below, "— Quantitative and Qualitative Disclosure About Market Risk — Interest Rate

Risks".

The credit facility contains certain financial covenants, including a minimum current ratio and a minimum present value to total debt ratio. The credit facility also contains certain covenants that are based on what is defined in the credit facility as EBITDAX. The credit facility defines EBITDAX as our net income, subject to certain adjustments for the particular period plus the following expenses or charges to the extent deducted from net income during that period: interest, income taxes, depreciation, depletion, amortization, exploration and abandonment expenses and other similar non-cash charges and expenses, including stock based compensation and non-cash impairments of goodwill, minus all non-cash income added to net income, in each case, and without duplication, calculated after giving pro forma effect to acquisitions and dispositions during the period. These covenants require that our debt to EBITDAX ratio cannot exceed 4.0 to 1.0 until November 30, 2005 and 3.5 to 1.0 thereafter, and that our EBITDAX to interest ratio cannot be below 2.5 to 1.0. We calculated our EBITDAX for 2004 to be $111.3 million so that our EBITDAX to interest ratio was 11.2 to 1.0 and our debt to EBITDAX ratio was 0 to 1.0. EBITDAX is not intended to represent net income (loss) as defined by generally accepted accounting principles in the United States, or GAAP, and such information should not be considered as an alternative to net income (loss), cash provided by operating activities or any other measure of performance prescribed by GAAP. We have complied with all financial covenants for all periods.

The current ratio covenant states that our current ratio adjusted for the unused portion of the borrowing base and to eliminate certain non-cash assets and liabilities related to hedging activities must be greater than 1.0. We calculated the ratio for December 31, 2004 to be 5.8.

The ratio of present value of oil and gas properties to total debt covenant states that the defined present value divided by the outstanding debt under the bank line of credit must not be less than 1.5. This ratio is calculated every six months based on engineering estimates calculated at commodity prices and present value factors determined by the lenders. At December 31, 2004, we were in compliance with this covenant. At December 31, 2004, there were no amounts outstanding under the credit facility.

Other Debt Financing. On September 1, 2004, we entered into a senior subordinated credit and guaranty agreement, or bridge loan, which had a total principal amount of $150 million. The bridge loan was used to pay the purchase price and transaction costs for the acquisition of our Piceance Basin properties and in December 2004 was repaid in full with a portion of the proceeds of our IPO as required by the terms of the loan.

Contractual Obligations. A summary of our contractual obligations as of December 31, 2004 is provided in the following table.

	Payments Due By Year (1)(2)(3)(4) (in thousands)						
	2005	2006	2007	2008	2009	After 2009	Total
Office and office equipment leases	$964	$956	$929	$911	$87	$-	$3,847
Firm transportation and other	1,232	2,245	2,245	2,245	2,245	15,485	25,697
Total	$2,196	$3,201	$3,174	$3,156	$2,332	$15,485	$29,544

(1) This table does not include the liability for dismantlement, abandonment and restoration costs of oil and gas properties. Effective with the adoption of SFAS No. 143, *Accounting for Asset Retirement Obligations*, we recorded a separate liability for the fair value of this asset retirement obligation.

(2) This table does not include any liability associated with derivatives.

(3) This table does not include any liability associated with commitment or other fees on our credit facility.

(4) This table does not include $1.8 million payment required to the Ute Tribe if we do not drill an exploratory well.

Effective March 1, 2004, we entered into a one-year firm transportation agreement with Questar Pipeline Company giving us guaranteed capacity on their pipeline for 8,500 MMBtu/d at a monthly charge of $45,000, with a total commitment of $540,000.

We entered into a firm transportation agreement for our natural gas production from the Wind River and Powder River Basins with Cheyenne Plains Company giving us guaranteed capacity on their pipeline, for a period of thirteen years and three months commencing upon the completion of the pipeline in February 2005. Contracted volumes are 9,000 MMBtu/d for the first 12 years and three months and 5,000 MMBtu/d for the final year. Our annual commitment based on 9,000 MMBtu/d is $1,117,000, which began in February 2005.

Effective September 1, 2004 as part of the acquisition of our Piceance Basin properties, we assumed the obligation of a firm transportation agreement with Questar Pipeline Company for 12,000 MMBtu/d of guaranteed pipeline capacity at a monthly charge of $94,000 per month for ten years beginning upon the completion of Questar's upgrade of its pipeline in the Piceance Basin, which is expected to be completed in November of 2005.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our financial statements. Below, we provide expanded discussion of our more significant accounting policies, estimates and judgments. We believe these accounting policies reflect our more significant estimates and assumptions used in preparation of our financial statements. See Note 2 of the Notes to the Consolidated Financial Statements for a discussion of additional accounting policies and estimates made by management.

Oil and Gas Properties

Our natural gas and oil exploration and production activities are accounted for using the successful efforts method. Under this method, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether the property has proved reserves. Generally, if an exploratory well is not assigned proved reserves within one year following completion of drilling, the costs of drilling the well are charged to exploration expense and included within cash flows from investing activities in the Consolidated Statements of Cash Flows pursuant to SFAS No. 19. The costs of development wells are capitalized whether productive or nonproductive. Gas and oil lease acquisition costs also are capitalized. If it is determined that these properties will not yield proved reserves, the related costs are expensed in the period in which that determination is made. Other exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for gas and oil leases, are charged to expense as incurred. The sale of a partial interest in a proved property is accounted for as a cost recovery and no gain or loss is recognized as long as this treatment does not significantly affect the unit-of-production amortization rate. A gain or loss is recognized for all other sales of proved properties. Maintenance and repairs are charged to expense and renewals and betterments are capitalized to the appropriate property and equipment accounts.

Unevaluated properties with significant acquisition costs are assessed periodically on a property-by-property basis and any impairment in value is charged to expense. Unevaluated properties whose acquisition costs are not individually significant are aggregated, and the portion of such costs estimated to be nonproductive, based on historical experience, is amortized over the average holding period. If the unevaluated properties are subsequently determined to be productive, the related costs are transferred to proved gas and oil properties. Proceeds, up to an amount equal to the total carrying amount, from sales of partial interests in unevaluated leases are accounted for as a recovery of cost without recognizing any gain or loss. We will record a gain on the sale of a partial interest in unevaluated leases for amounts equal to the excess of proceeds over our total carrying amount of such leases. In 2003, we recorded impairment expense of $1.8 million related to unevaluated properties located in southern Montana.

We review our proved natural gas and oil properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. We estimate the expected future cash flows of our gas and oil properties and compare these future cash flows to the carrying amount of the gas and oil properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will adjust the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value include, but are not limited to, estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures, and a discount rate commensurate with the risk associated with realizing the expected cash flows projected. In 2004, we recorded impairment expense of $0.5 million related to the evaluated costs of the Talon Field in Wyoming's Wind River Basin at December 31, 2004.

Our investment in natural gas and oil properties includes an estimate of the future costs associated with dismantlement, abandonment and restoration of our properties. These costs are recorded as provided in SFAS No. 143. The present value of the future costs are added to the capitalized costs of our oil and gas properties and recorded as a long-term liability. The capitalized cost is included in the natural gas and oil property costs that are depleted over the life of the assets. The liability for future reclamation costs increased $7.5 million to $11.8 million at December 31, 2004 from $4.3 million at December 31, 2003 as a result of increases in our investment in natural gas and oil properties during that period from the acquisition of our Piceance Basin properties and the completion of successful wells and support equipment and facilities.

The provision for depreciation, depletion and amortization ("DD&A") of oil and gas properties is calculated on a field-by-field basis using the unit-of-production method. Oil is converted to natural gas equivalents, Mcfe, at the rate of one barrel to six Mcf. Taken into consideration in the calculation of DD&A are estimated future dismantlement, restoration and abandonment costs, net of estimated salvage values.

Oil and Gas Reserve Quantities

Our estimate of proved reserves is based on the quantities of oil and gas that engineering and geological analysis demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Ryder Scott Company reviews all our reserve estimates except our reserve estimates for the Powder River Basin, which are reviewed by Netherland, Sewell & Associates. A reserve report is prepared by us for all properties and these independent engineering firms review the entire report on a well-by-well basis.

Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. We prepare our reserve estimates, and the projected cash flows derived from these reserve estimates, in accordance with SEC guidelines. The independent engineering firms described above adhere to the same guidelines when reviewing our reserve reports. The accuracy of our reserve estimates is a function of many factors including the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions, and the judgments of the individuals preparing the estimates.

Our proved reserve estimates are a function of many assumptions, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the ultimate quantities of oil, natural gas, and natural gas liquids eventually recovered. At year end 2004, we revised our proved reserves downward from the 2003 reserve report by approximately 32 Bcfe, offset by approximately 6 Bcfe of upward revisions due to commodity price increases. At year end 2003, we revised our proved reserves downward from the 2002 reserve report by approximately 41 Bcfe, offset by approximately 5 Bcfe of upward revisions due to commodity price increases.

Revenue Recognition

We record revenues from the sales of natural gas and oil when delivery to the customer has occurred and title has transferred. This occurs when oil or gas has been delivered to a pipeline or a tank lifting has occurred.

We may have an interest with other producers in certain properties, in which case we use the sales method to account for gas imbalances. Under this method, revenue is recorded on the basis of natural gas actually sold by the Company. In addition, we record revenue for our share of natural gas sold by other owners that cannot be volumetrically balanced in the future due to insufficient remaining reserves. We also reduce revenue for other owners' gas sold by the Company that cannot be volumetrically balanced in the future due to insufficient remaining reserves. Our remaining over-and under-produced gas balancing positions are considered in our proved reserves. Gas imbalances as of December 31, 2003 and 2004 were not significant.

Derivative Instruments and Hedging Activities

We periodically use derivative financial instruments to achieve a more predictable cash flow from our gas and oil production by reducing our exposure to price fluctuations. As of December 31, 2004, these transactions are swaps and cashless collars which have been entered into with J. Aron & Company, a major financial institution and affiliate of Goldman, Sachs & Co., which was an underwriter for our IPO and is affiliated with certain of our institutional investors. We account for these activities pursuant to SFAS No. 133, as amended. This statement establishes accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded at fair market value and included in the balance sheet as assets or liabilities.

The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. SFAS No. 133 requires a company to formally document, at the inception of a hedge, the hedging relationship and the entity's risk management objective and strategy for undertaking the hedge, including identification of the hedging instrument, the hedged item or transaction, the nature of the risk being hedged, the method that will be used to assess effectiveness and the method that will be used to measure hedge ineffectiveness of derivative instruments that receive hedge accounting treatment.

For derivative instruments designated as cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. Hedge effectiveness is assessed at least quarterly based on total changes in the derivative's fair value. Any ineffective portion of the derivative instrument's change in fair value is recognized immediately in earnings.

We may use derivative financial instruments which have not been designated as hedges under SFAS No. 133 even though they protect our company from changes in commodity prices. These instruments, if used, will be marked to market with the resulting changes in fair value recorded in earnings.

As of December 31, 2004 the fair value of the derivative positions for our oil and gas swaps and gas collars for 2005 and 2006 production was $5.7 million and recorded on the balance sheet as a current liability of $3.9 million for the settlements expected to be paid within one year and other noncurrent liabilities of $1.8 million for the settlements expected to be paid later than one year. The deferred income tax effect on the $5.7 million fair value of derivatives at December 31, 2004 totaled $2.1 million which is recorded in current and noncurrent deferred tax assets.

Income Taxes

Income taxes are provided for the tax effects of transactions reported in the financial statements and consist of taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income tax assets and liabilities represent the future tax return consequences of those differences, which will either be taxable or deductible when assets are recovered or settled. Deferred income taxes are also recognized for tax credits that are available to offset future income taxes. Deferred income taxes are measured by applying currently enacted tax rates to the differences between financial statement and income tax reporting. We have not recognized a valuation allowance against our net deferred taxes because we believe that it is more likely than not that the net deferred tax assets will be realized based on estimates of our future operating income.

Stock-based Compensation

In December 2004, the Financial Accounting Standards Board ("FASB") issued SFAS No. 123 (revised 2004) ("SFAS No. 123R"), *Share-Based Payment,* which revises SFAS No. 123, *Accounting for Stock-Based Compensation* and supersedes Accounting Principles Board ("APB") Opinion No. 25, *Accounting for Stock Issued to Employees.* We early adopted the provisions of the new standard effective October 1, 2004. Prior to the adoption of SFAS No. 123R, we used the intrinsic value method in accordance with APB Opinion No. 25 and the disclosure only provisions of SFAS No. 123.

Restrictions on the vesting of Management Stock and options granted under our 2002 Stock Option Plan (the "2002 Option Plan") were put in place in connection with the initial capitalization of the Company, including Series A and B preferred stock issuances, and were designed to ensure that the relative ownership interests of Series B preferred stock investors were not diluted. Thus, the Management Stock and option grants under the 2002 Option Plan only vested if capital was raised from Series A and Series B investors (or upon other capital raising events). This is referred to as "dollar vesting" in the case of Management Stock and "equity vesting" in the case of options granted under the 2002 Option Plan. Dollar vested Management Stock and equity vested options are further subject to time vesting provisions. As of May 12, 2004, all Management Stock and options granted under the 2002 Option Plan were fully dollar and equity vested.

We recorded non-cash stock-based compensation of $1.3 million, $3.6 million and $3.0 million in 2002, 2003 and 2004, respectively, for the Management Stock awards and option grants, in addition to Series B preferred stock purchases by employees at less than estimated fair value for financial reporting purposes. For awards granted after we were a public company (those granted subsequent to our initial filing of the registration statement for our IPO on April 16, 2004 as defined in SFAS No. 123R), we adopted SFAS No. 123R using the modified prospective application effective October 1, 2004, whereby as of that date we began applying the provisions of SFAS No. 123R to new awards and to awards modified, repurchased, or cancelled after that date. We recognized share-based employee compensation cost based on the historical grant-date fair value as computed under SFAS No. 123 on that date for the portion of awards previously issued and for which the requisite service had not yet been rendered, and all deferred compensation related to those awards was eliminated against the appropriate equity accounts on the adoption date. For awards granted while we were a nonpublic company (those granted previous to April 16, 2004 as defined in SFAS No. 123R), we adopted SFAS No. 123R using the prospective transition method, under which we continue to account for the portion of the award outstanding at the date of application using the minimum value method described under SFAS No. 123.

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

The fair value of our common stock for stock-based awards granted during March 2002 through September 2003 was originally estimated on a contemporaneous basis by management as having a value of no greater than $0.41 per share for financial reporting purposes. Our computations during that period indicated that the corporate values of our assets, principally acquired properties, did not exceed the preferred stock preference amounts. For determining our fair value at December 31, 2003 and subsequent dates, we prepared valuation reports based on methodologies consistent with those that were proposed in the then-draft AICPA Practice Aid, "Valuation of Privately Held Company Equity Securities Issued as Compensation", which subsequently was issued in final form in 2004. Since December 2003, we have contemporaneously prepared at least one valuation report per quarter, which were provided to the board of directors and used by the compensation committee when approving stock option grants.

Prior to closing our IPO, determining the fair value of our stock required making complex and subjective judgments. For our retrospective valuations used to calculate non-cash deferred compensation and stock-based compensation expense reported in the financial statements, we used a probability-weighted expected return method. Under the probability-weighted expected return method, the value of the common stock was estimated based upon an analysis of values for us assuming various outcomes (initial public offering, merger or sale, liquidation, and remaining private) and the estimated probability of each outcome assuming that all preferred stock is converted into common stock. As we progressed through the IPO process, we placed increasing weight on an initial public offering or merger or sale within the probability-weighted expected return method.

Our valuation comparisons and estimates were inherently uncertain. The assumptions underlying the estimates were consistent with our business plan. The risks associated with achieving various outcomes related to our forecasts were assessed when selecting the weighting within the probability-weighted expected return method. If different probabilities had been used, the valuations would have been different. Furthermore, we did not use an unrelated valuation specialist. However, we believe that our management team has the appropriate expertise and experience to perform such analyses and we utilized methodologies acknowledged in the AICPA Practice Aid, but the valuation results we calculated may be different than what an unrelated valuation specialist may have calculated.

Acquisitions

The establishment of our initial asset base since our founding in January 2002 has included five major acquisitions of oil and natural gas properties. These acquisitions have been accounted for using the purchase method of accounting.

Under the purchase method, the acquiring company adds to its balance sheet the estimated fair values of the acquired company's assets and liabilities. Any excess of the purchase price over the fair values of the tangible and intangible net assets acquired is recorded as goodwill. Goodwill is assessed for impairment at least annually. In each of our acquisitions it was determined that the purchase price did not exceed the fair value of the net assets acquired. Therefore, no goodwill was recorded.

There are various assumptions we made in determining the fair values of acquired assets and liabilities. The most significant assumptions, and the ones requiring the most judgment, involve the estimated fair values of the natural gas and oil properties acquired. To determine the fair values of these properties, we prepare estimates of natural gas and oil reserves. These estimates are based on work performed by our engineers and that of outside consultants. The fair value of reserves acquired in a business combination must be based on our estimates of future natural gas and oil prices and not the prices at the time of the acquisition. Our estimates of future prices are based on our own analysis of pricing trends. These estimates are based on current data obtained with regard to regional and worldwide supply and demand dynamics such as economic growth forecasts. They also are based on industry data regarding natural gas storage availability, drilling rig activity, changes in delivery capacity, trends in regional pricing differentials and other fundamental analysis. Forecasts of future prices from independent third parties are noted when we make our pricing estimates.

We estimate future prices to apply to the estimated reserve quantities acquired, and estimate future operating and development costs, to arrive at estimates of future net revenues. For estimated proved reserves, the future net revenues are then discounted using a rate determined appropriate at the time of the business combination based upon our cost of capital.

We also apply these same general principles in arriving at the fair value of unevaluated properties acquired in a business combination. These unevaluated properties generally represent the value of probable and possible reserves. Because of their very nature, probable and possible reserve estimates are more imprecise than those of proved reserves. To compensate for the inherent risk of estimating and valuing probable and possible reserves, we apply a risk-weighting factor to probable and possible volumes to reduce the estimated reserve volumes. Additionally, we increase the discount factor, compared to proved reserves, to recognize the additional uncertainties related to determining the value of probable and possible reserves.

Tranche A Option Accounting

We allowed the holders of outstanding Tranche A Options to amend those options, effective upon the completion of our IPO, to provide that each option to purchase one share of common stock for $30.28 per share became an option to purchase a number of shares of common stock at the IPO price of $25.00 per share that had an estimated fair value equivalent to the estimated fair value of the outstanding Tranche A Options based on a Black-Scholes model calculation. As a result of this modification, the number of options to these holders was reduced by approximately 7.4% in order for the fair value of the options before the modification to be equal to the fair value after the modification based on a Black-Scholes model calculation. Because the fair value of these options before and after the modification remained the same, no additional stock-based compensation expense was required to be recorded under the modified prospective application of SFAS No. 123R.

New Accounting Pronouncements

In March 2004, FASB issued consensus on Emerging Issues Task Force ("EITF") 03-6, *Participating Securities and the Two-Class Method Under FASB Statement No. 128, Earnings Per Share,* related to calculating earnings per share with respect to using the two class method for participating securities. This pronouncement is effective for all periods after March 31, 2004, and requires earlier periods to be restated. We were early adopters of this pronouncement. Our earnings per share for the period January 7, 2002 (inception) through December 31, 2002 and the year ended December 31, 2003 reflect the two class method as our preferred convertible securities are deemed participating under EITF 03-6. The adoption of EITF 03-6 had no impact on our financial position, results of operations or cash flows.

In September 2004, the FASB issued FASB Staff Position ("FSP") EITF Issue 03-1-1, Effective Date of Paragraphs 10-20 of EITF Issue No. 03-1, *The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments*, which delays the effective date for the recognition and measurement guidance in EITF Issue No. 0-3-1. In addition, the FASB has issued a proposed FSP to consider whether further application guidance is necessary for securities analyzed for impairment under EITF Issue No. 03-1. We continue to assess the potential impact that the adoption of the proposed FSP could have on our financial statements.

Quantitative and Qualitative Disclosure About Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our U.S. natural gas production. Pricing for oil and natural gas production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control. Based on our average daily production and our price swap contracts in place in 2004, our annual income before income taxes for the year ended December 31, 2004 would have changed by approximately $1.6 million for each $0.10 change in natural gas prices and approximately $0.4 million for each $1.00 change in crude oil prices.

We periodically have entered into and anticipate entering into financial hedging activities with respect to a portion of our projected natural gas and oil production through various financial transactions which hedge the future prices received. These transactions may include financial price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty, and cashless price collars that set a floor and ceiling price for the hedged production. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, we and the counterparty to the collars would be required to settle the difference. These financial hedging activities are intended to support natural gas and oil prices at targeted levels and to manage our exposure to oil and gas price fluctuations. We do not hold or issue derivative instruments for speculative trading purposes.

As of March 1, 2005, we had hedges in place for approximately 17 Bcf and 12 Bcf of natural gas production for 2005 and 2006, respectively, and approximately 244 MBbls and 256 MBbls of oil production for 2005 and 2006, respectively. These hedges are summarized in the table presented above under "— Cash Flow from Operating Activities". Based on the pricing and contracts outstanding as of March 1, 2005, the estimated fair value of our hedge positions was a liability of $17.0 million owed by us to the counterparty. If future oil and gas prices at March 1, 2005 had declined by 10%, the net unrealized hedging losses at that date would have decreased by $7.0 million (from $17.0 million to $10.0 million).

Price Swaps

Through various price swaps, we have fixed the price we will receive on a portion of our natural gas and oil production in 2005. The table presented above under "— Cash Flow from Operating Activities" provides the volumes associated with these various arrangements as of March 1, 2005.

In a swap transaction, the counterparty is required to make a payment to us for the difference between the fixed price and the settlement price if the settlement price is below the fixed price. We are required to make a payment to the counterparty for the difference between the fixed price and the settlement price if the fixed price is below the settlement price.

Price Collars

Through price collars, we have fixed the minimum price we will receive on a portion of our natural gas production in 2005 and 2006 based on floors referencing a $4.75 and $5.00, respectively, per MMBtu Northwest Pipeline Corp. Rocky Mountain price and a $5.00 per MMBtu Colorado Interstate Gas Rocky Mountain price. We have also fixed the minimum price we will receive on a portion of our oil production in 2005 and 2006 based on floors referencing a $45.00 and $42.00 per Bbl West Texas Intermediate price, respectively. The price collars also allow us to share in upward price movements up to the ceiling prices referenced in the contracts. The table presented above under "— Cash Flow from Operating Activities" provides the volumes and floor and ceiling prices associated with these various arrangements as of March 1, 2005.

In a collar transaction, the counterparty is required to make a payment to us for the difference between the fixed floor price and the settlement price if the settlement price is below the fixed floor price. We are required to make a payment to the counterparty for the difference between the fixed ceiling price and the settlement price if the fixed ceiling price is below the settlement price. Neither party is required to make a payment if the settlement price falls between the fixed floor and ceiling price.

Interest Rate Risks

At December 31, 2004, we had no outstanding debt. Amounts drawn against our $200 million revolving credit facility bear interest at floating rates as defined in the facility. The average annual interest rate incurred on this debt for the year ended December 31, 2003 and 2004 was 3.7% and 3.6%, respectively. The weighted average amount outstanding in 2004 under our credit facility was $73.7 million. A one hundred basis point (1.0%) increase in each of the LIBOR rate and federal funds rate would result in an estimated $0.7 million increase in annual interest expense assuming a similar average debt level to the year ended December 31, 2004.

RISK FACTORS

The Company's business involves a high degree of risk. You should carefully consider the following risks and all of the other information contained in this Form 10-K before deciding to invest in our common stock. The risks described below are not the only ones facing our company. Additional risks not presently known to us or which we currently consider immaterial also may adversely affect our company.

Risks Related to the Oil and Natural Gas Industry and Our Business

Oil and natural gas prices are volatile and a decline in oil and natural gas prices can significantly affect our financial results and impede our growth.

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

- the domestic and foreign supply of oil and natural gas;
- the price of foreign imports;

- overall domestic and global economic conditions;
- political and economic conditions in oil producing countries, including the Middle East and South America;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the level of consumer product demand;
- weather conditions;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations;
- proximity and capacity of oil and gas pipelines and other transportation facilities; and
- the price and availability of alternative fuels.

Lower oil and natural gas prices may not only decrease our revenues on a per unit basis, but also may reduce the amount of oil and 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, successful efforts accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas 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.

Our business is difficult to evaluate because we have a limited operating history.

In considering whether to invest in our common stock, you should consider that there is only limited historical financial and operating information available on which to base your evaluation of our performance. We were formed in January 2002 and, as a result, we have a limited operating history.

We have incurred losses from operations during certain periods since our inception and may continue to do so in the future.

We incurred net losses of $5.0 million, $4.0 million, and $5.3 million in the period from January 7, 2002 (inception) through December 31, 2002 and the years ended December 31, 2003 and 2004, respectively. Our development of and participation in an increasingly larger number of prospects has required and will continue to require substantial capital expenditures. The uncertainty and factors described throughout this section may impede our ability to economically find, develop, exploit, and acquire natural gas and oil reserves. As a result, we may not be able to achieve or sustain profitability or positive cash flows from operating activities in the future.

Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

No one can measure underground accumulations of oil and natural gas in an exact way. Oil and natural gas reserve engineering requires subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, production levels, and operating and development costs. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may be incorrect. We prepare our own estimates of proved reserves, which are reviewed by independent petroleum engineers. Over time, our internal engineers may make material changes to reserve estimates taking into account the results of actual drilling, testing, and production. Also, we make certain assumptions regarding future oil and 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 reserves, the economically recoverable quantities of oil and 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. Some of our reserve estimates are made without the benefit of a lengthy production history, which are less reliable than estimates based on a lengthy production history. At year end 2004, we revised our proved reserves downward from our 2003 reserve report by approximately 32 Bcfe. The downward revision was primarily the result of infill drilling in depleted sands in the Wind River Basin and greater pressure depletion than expected in two areas in the Power River Basin. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of oil and gas we ultimately recover being different from our reserve estimates.

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

- actual prices we receive for oil and natural gas;
- the amount and timing of actual production;
- supply of and demand for oil and natural gas; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from 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 oil and natural gas industry in general. For example, if natural gas prices decline by $0.10 per Mcf, then the PV-10 of our proved reserves as of December 31, 2004 would decrease from $592 million to $576 million.

Our independent engineers perform a well-by-well review of all of our properties and of our estimates of proved reserves, but the review report they issue to us only addresses the total amount of our estimates for the sum of all properties covered by our reserve report. These review reports do not state the degree of their concurrence with the accuracy of our estimate for the proved reserves attributable to our interest in any specific basin, property or well, although this information is generated by the independent engineers as a basis for their review report. In a well-by-well comparison by the independent engineers, differences of greater or less than 10% exist. For estimates of proved reserves at December 31, 2004, these comparisons by the independent engineers arrived at reserve estimates that are greater than 10% above or below our own estimates for approximately 53% of our conventional wells, which represents approximately 40% of the total proved reserves covered in the review reports. In the case of the properties reviewed by each of the two independent engineers, our estimates of proved reserves at December 31, 2004 in the aggregate were 9.8% above those of Ryder Scott Company, L.P. and at December 31, 2004 in the aggregate were 9.7% above Netherland, Sewell & Associates, Inc.

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

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our reserve report at December 31, 2004, shows an estimated decline rate after 2005 of approximately 7.2% per year in our total estimated proved reserves at December 31, 2004. Because total estimated proved reserves include our proved undeveloped reserves at December 31, 2004, production will decline at this rate even if those proved undeveloped reserves are developed and the wells produce as expected. This rate of decline will change if production from our existing wells declines in a different manner than we have estimated and can change under other circumstances. Thus, our future oil and 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.

Prospects that we decide to drill may not yield natural gas or oil in commercially viable quantities.

We describe some of our current prospects and our plans to explore those prospects in this Annual Report on Form 10-K. A prospect is a property on which we have identified what our geoscientists believe, based on available seismic and geological information, to be indications of natural gas or oil. Our prospects are in various stages of evaluation, ranging from a prospect that is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation. However, the use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling and testing whether natural gas or oil will be present or, if present, whether natural gas or oil will be present in sufficient quantities to recover drilling or completion costs or to be economically viable. From inception through December 31, 2004, we participated in drilling a total of 474 gross wells, of which 15 have been identified as dry holes. If we drill additional wells that we identify as dry holes in our current and future prospects, our drilling success rate may decline and materially harm our business. In sum, the cost of drilling, completing and operating any wells is often uncertain and new wells may not be productive.

Many of our leases in the Powder River Basin are in areas that have been partially depleted or drained by offset wells.

The Powder River Basin represents a significant part of our drilling program and production growth in 2005. Our development operations are conducted in seven project areas in this basin. Nearly all of our operations are in coalbed methane plays. Our key project areas are located in both the Big George and Wyodak fairways, which has been the most active drilling area in the Rocky Mountain Region. As a result, many of our leases in the Wyodak are in areas that have already been partially depleted or drained by earlier offset drilling. This may inhibit our ability to find economically recoverable quantities of natural gas in these areas.

Our identified drilling location inventories are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management has specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These identified drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including the availability of capital, seasonal conditions, regulatory approvals, oil and natural gas prices, costs and drilling results. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce natural gas or oil from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

Our use of 2-D and 3-D seismic data is subject to interpretation and may not accurately identify the presence of natural gas and oil, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures. As a result, our drilling activities may not be successful or economical and our overall drilling success rate or our drilling success rate for activities in a particular area could decline.

We often gather 3-D seismic over large areas. Our interpretation of seismic data delineates for us those portions of an area that we believe are desirable for drilling. Therefore, we may chose not to acquire option or lease rights prior to acquiring seismic data and, in many cases, we may identify hydrocarbon indicators before seeking option or lease rights in the location. If we are not able to lease those locations on acceptable terms, it would result in our having made substantial expenditures to acquire and analyze 3-D data without having an opportunity to attempt to benefit from those expenditures.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our drilling activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for oil and natural gas can be unprofitable, not only from dry holes, but from productive wells that do not produce sufficient revenues to return a profit. In addition, our drilling and producing operations may be curtailed, delayed or canceled as a result of other factors, including:

- unusual or unexpected geological formations;
- pressures;

- fires;
- blowouts;
- loss of drilling fluid circulation;
- title problems;
- facility or equipment malfunctions;
- unexpected operational events;
- shortages or delivery delays of equipment and services;
- compliance with environmental and other governmental requirements; and
- adverse weather conditions.

Additionally, the coal beds in the Powder River Basin from which we produce methane gas frequently contain water, which may hamper our ability to produce gas in commercial quantities. The amount of coalbed methane that can be commercially produced depends upon the coal quality, the original gas content of the coal seam, the thickness of the seam, the reservoir pressure, the rate at which gas is released from the coal, and the existence of any natural fractures through which the gas can flow to the well bore. However, coal beds frequently contain water that must be removed in order for the gas to detach from the coal and flow to the well bore. The average life of a coal bed well is only five to six years. Our ability to remove and dispose of sufficient quantities of water from the coal seam will determine whether or not we can produce coalbed methane in commercial quantities.

Any of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination or loss of wells and other regulatory penalties.

We ordinarily maintain insurance against various losses and liabilities arising from our operations; however, insurance against all operational risks is not available to us. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Thus, losses could occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse impact on our business activities, financial condition and results of operations.

Our development and exploration operations require substantial capital and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our natural gas and oil reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration for and development, production and acquisition of oil and natural gas reserves. To date, we have financed capital expenditures primarily with sales of our equity securities, proceeds from bank borrowings and cash generated by operations. We intend to finance our capital expenditures with cash flow from operations and our existing financing arrangements. Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of oil and natural gas we are able to produce from existing wells;
- the prices at which oil and natural gas are sold; and
- our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our revolving credit facility decreases as a result of lower oil and 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 and the bridge loan we obtained to finance our acquisition of the Piceance Basin properties in September 2004 restrict our ability to obtain new financing. There can be no assurance as to the availability or terms of any additional financing.

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 prospects, which in turn could lead to a possible loss of properties and a decline in our natural gas and oil reserves.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of doing business.

Our exploration, development, production and marketing operations are regulated extensively at the federal, state and local levels. In addition, a portion of our leases in the Uinta basin are, and some of our future leases may be, regulated by Native American tribes. Environmental and other governmental laws and regulations have increased the costs to plan, design, drill, install, operate and abandon oil and natural gas wells. Under these laws and regulations, we could also be liable for personal injuries, property damage and other damages. Failure to comply with these laws and regulations may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain drilling projects.

Our Powder River Basin coalbed methane exploration and production activities result in the discharge of large volumes of produced groundwater into adjacent lands and waterways. The ratio of methane gas to produced water varies over the life of the well. The environmental soundness of discharging produced groundwater pursuant to water discharge permits has come under increased scrutiny. Moratoriums on the issuance of additional water discharge permits, or more costly methods of handling these produced waters, may affect future well development. Compliance with more stringent laws or regulations, or more vigorous enforcement policies of the regulatory agencies, or difficulties in negotiating required surface use agreements with land owners, or receiving other governmental approvals, could delay our Powder River Basin exploration and production activities and/or require us to make material expenditures for the installation and operation of systems and equipment for pollution control and/or remediation, all of which could have a material adverse effect on our financial condition or results of operations.

Part of the regulatory environment in which we operate includes, in some cases, federal requirements for performing or preparing environmental assessments, environmental impact studies and/or plans of development before commencing exploration and production activities. In addition, our activities are subject to the regulation by oil and natural gas-producing states and Native American tribes of conservation practices and protection of correlative rights. These regulations affect our operations and limit the quantity of oil and natural gas we may produce and sell. A major risk inherent in our drilling plans is the need to obtain drilling permits from state, local and Native American tribal authorities. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well or the receipt of a permit with excessive conditions or costs could have a material adverse effect on our ability to explore on or develop our properties. Additionally, the oil and natural gas regulatory environment could change in ways that might substantially increase the financial and managerial costs to comply with the requirements of these laws and regulations and, consequently, adversely affect our profitability. Furthermore, we may be put at a competitive disadvantage to larger companies in our industry who can spread these additional costs over a greater number of wells and larger operating staff. See "Items 1 and 2. Business and Properties—Business — Operations — Environmental Matters and Regulation" and "Items 1 and 2. Business and Properties—Business — Operation — Other Regulation of the Oil and Gas Industry" for a description of the laws and regulations that affect us.

Substantially all of our producing properties are located in the Rocky Mountains, making us vulnerable to risks associated with operating in one major geographic area.

Our operations are focused on the Rocky Mountain region, which means our producing properties are geographically concentrated in that area. In particular, a substantial portion of our proved oil and natural gas reserves are located in the Piceance and Wind River Basins. At December 31, 2004, approximately 30.3% of our proved reserves and approximately 6.6% of our December 2004 production were located in the Piceance Basin and approximately 28.3% of our proved reserves and approximately 44.9% of our December 2004 production were located in the Wind River Basin. As a result, 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 or interruption of transportation of natural gas produced from the wells in these basins.

Seasonal weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and natural gas operations in the Rocky Mountains are adversely affected by seasonal weather conditions and lease stipulations designed to protect various wildlife. In certain areas, including parts of the Wind River and Uinta Basins, drilling and other oil and natural gas activities can only be conducted during the spring and summer months. This limits our ability to operate in those areas and can intensify competition during those months for drilling rigs, oil field equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs. We encountered limitations on our activities in the West Tavaputs area earlier than expected in the fourth quarter of 2004, which prevented us from completing wells and booking reserves associated with those wells and increased our costs as we were required to remove a completion rig and will incur the expense of bringing that rig back in and additional demobilizing costs when the winter stipulations end in the spring of 2005. See "Items 1 and 2. Business and Properties—Uinta Basin—West Tavaputs".

Properties that we buy may not produce as projected and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against them.

One of our growth strategies is to capitalize on opportunistic acquisitions of oil and natural gas reserves. However, our reviews of acquired properties are inherently incomplete because it generally is not feasible to review in depth every individual property involved in each acquisition. Ordinarily, we will focus our review efforts on the higher value properties and will sample the remainder. However, even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, we often assume certain environmental and other risks and liabilities in connection with acquired properties.

We have limited control over activities on properties we do not operate, which could reduce our production and revenues.

Substantially all of our business activities are conducted through joint operating agreements under which we own partial interests in oil and natural gas properties. If we do not operate the properties in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of underlying properties. The failure of an operator of our wells to adequately perform operations, or an operator's breach of the applicable agreements, could reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others therefore depends upon a number of factors outside of our control, including the operator's timing and amount of capital expenditures, expertise and financial resources, inclusion of other participants in drilling wells, and use of technology. Because we do not have a majority interest in most wells we do not operate, we may not be in a position to remove the operator in the event of poor performance.

Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells for a lack of a market or because of inadequacy or unavailability of natural gas pipeline, gathering system capacity or processing facilities. If that were to occur, then we would be unable to realize revenue from those wells until production arrangements were made to deliver the production to market.

Our hedging activities could result in financial losses or could reduce our income.

To achieve a more predictable cash flow, to reduce our exposure to adverse fluctuations in the prices of oil and natural gas and to comply with credit agreement requirements, we currently, and may in the future, enter into hedging arrangements for a portion of our oil and natural gas production. Hedging arrangements for a portion of our oil and natural gas production expose us to the risk of financial loss in some circumstances, including when:

- production is less than expected;
- the counter-party to the hedging contract defaults on its contract obligations; or
- there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received.

In addition, these types of hedging arrangements limit the benefit we would receive from increases in the prices for oil and natural gas and may expose us to cash margin requirements.

The inability of one or more of our customers to meet their obligations may adversely affect our financial results.

Substantially all of our accounts receivable result from oil and natural gas sales or joint interest billings to third parties in the energy industry. This concentration of customers and joint interest owners may impact our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. In addition, our oil and natural gas hedging arrangements expose us to credit risk in the event of nonperformance by counterparties.

We depend on a limited number of key personnel who would be difficult to replace.

We depend on the performance of our executive officers and other key employees, especially William J. Barrett, our Chairman and Chief Executive Officer. The loss of any member of our senior management or other key employees could negatively impact our ability to execute our strategy. We do not maintain key person life insurance policies on any of our employees. For a description of our management philosophy, see "Item 10. Directors and Executive Officers of the Registrant—Management — Executive Officers, Directors and Other Key Employees — Management Philosophy".

Competition in the oil and natural gas industry is intense, which may adversely affect our ability to succeed.

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices. Our larger competitors may be able to absorb the burden of present and future federal, state, local and other laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties.

Our credit facility has substantial restrictions and financial covenants and we may have difficulty obtaining additional credit, which could adversely affect our operations.

We will depend on our revolving credit facility for future capital needs. The revolving credit facility restricts our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations. We also are required to comply with certain financial covenants and ratios. Our ability to comply with these restrictions and covenants in the future is uncertain and will be affected by the levels of cash flow from our operations and events or circumstances beyond our control. Our failure to comply with any of the restrictions and covenants under the revolving credit facility could result in a default under those facilities, which could cause all of our existing indebtedness to be immediately due and payable.

The revolving credit facility limits the amounts we can borrow to a borrowing base amount, determined by the lenders in their sole discretion, based upon projected revenues from the oil and natural gas properties securing our loan. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under the revolving credit facility. Any increase in the borrowing base requires the consent of the lenders holding 75% of the commitments. If the required lenders do not agree on an increase, then the borrowing base will be the lowest borrowing base acceptable to the required number of lenders. Outstanding borrowings in excess of the borrowing base must be repaid immediately, or we must pledge other oil and natural gas properties as additional collateral. We do not currently have any substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments required under the revolving credit facility.

Risks Related to Our Common Stock

Prior to our December 2004 initial public offering, there was no public market for our common stock and our stock price may fluctuate significantly.

Prior to our initial public, there has been no public market for our common stock. We cannot assure you that an active trading market will develop or be sustained. The initial public offering price was determined through negotiation between us and representatives of the underwriters and may not be indicative of the market price for our common stock. The market price of our common stock could fluctuate significantly as a result of:

- actual or anticipated quarterly variations in our operating results;

- changes in expectations as to our future financial performance or changes in financial estimates, if any, of public market analysts;
- announcements relating to our business or the business of our competitors;
- conditions generally affecting the oil and natural gas industry;
- the success of our operating strategy; and
- the operating and stock price performance of other comparable companies.

Future sales of our common stock may cause our stock price to decline.

Sales of substantial amounts of our common stock in the public market, or the perception that these sales may occur, could cause the market price of our common stock to decline. In addition, the sale of these shares could impair our ability to raise capital through the sale of additional common or preferred stock.

As of March 1, 2005, we have 43,362,738 shares of common stock outstanding, excluding stock options. All shares sold in our initial public offering, other than shares purchased by our affiliates, are freely tradable.

The institutional investors, officers and directors, certain other previous investors, and purchasers through a directed share program are subject to agreements that limit their ability to sell our common stock held by them. These holders cannot sell or otherwise dispose of any shares of our common stock, subject to limited exceptions, until June 9, 2005, which period may be extended under limited circumstances, without the prior written approval of Goldman, Sachs & Co., which could, in its sole discretion, elect to permit resale of shares by existing stockholders, including its affiliates, prior to June 9, 2005.

Provisions in our certificate of incorporation and bylaws and Delaware law make it more difficult to effect a change in control of the company, which could adversely affect the price of our common stock.

Delaware corporate law and our restated certificate of incorporation and bylaws contain provisions that could delay, defer or prevent a change in control of us or our management. These provisions include:

- a classified board of directors;
- giving the board the exclusive right to fill all board vacancies;
- requiring a super-majority vote of the stockholders for the removal of directors;
- permitting removal of directors only for cause and with a super-majority vote of the stockholders;
- requiring special meetings of stockholders to be called only by the board;
- requiring advance notice for stockholder proposals and director nominations;
- prohibiting stockholder action by written consent;
- prohibiting cumulative voting in the election of directors; and
- allowing for authorized but unissued common and preferred shares, including shares used in a shareholder rights plan.

These provisions also could discourage proxy contests and make it more difficult for you and other stockholders to elect directors and take other corporate actions. As a result, these provisions could make it more difficult for a third party to acquire us, even if doing so would benefit our stockholders, which may limit the price that investors are willing to pay in the future for shares of our common stock.

We have significant stockholders with the ability to influence our actions.

Warburg Pincus Private Equity VIII, L.P. and entities affiliated with each of The Goldman Sachs Group, Inc. and J.P. Morgan

Partners, LLC (each an "institutional investor") beneficially own approximately 49% of our outstanding common stock. See "Principal Stockholders". Accordingly, these stockholders may be able to control the outcome of stockholder votes, including votes concerning the election of directors, the adoption or amendment of provisions in our certificate of incorporation or bylaws and the approval of mergers and other significant corporate transactions. This concentrated ownership makes it less likely that any other holder or group of holders of common stock will be able to affect the way we are managed or the direction of our business. These factors also may delay or prevent a change in our management or voting control.

Furthermore, conflicts of interest could arise in the future between us, on the one hand, and the institutional investors, on the other hand, concerning among other things, potential competitive business activities or business opportunities. None of the institutional investors is restricted from competitive oil and natural gas exploration and production activities or investments, and our certificate of incorporation contains a provision that permits the institutional investors to participate in transactions relating to the acquisition, development and exploitation of oil and natural gas reserves without making such opportunities available to us.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The information required by this item is included above in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Quantitative and Qualitative Disclosure About Market Risk".

Item 8. Financial Statements and Supplementary Data

The information required by this item is included below in "Item 15. Exhibits, Financial Statements and Financial Statement Schedules".

Item 9. Changes in and Disagreements With Accountants and Financial Disclosure

Not applicable.

Item 9A. Controls and Procedures

Evaluation of disclosure controls and procedures. Based on an evaluation carried out under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, as of the end of the period covered by this report, our Chief Executive Officer and Chief Financial Officer believe that our disclosure controls and procedures, as defined in Securities Exchange Act Rules 13a-15(d) and 15d-15(e), were, as of the end of the period covered by this report, to the best of their knowledge, effective.

Changes in internal controls. There has been no change in our internal control over financial reporting during the fourth fiscal quarter of 2004 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

Not applicable.

PART III

Item 10. Directors and Executive Officers of the Registrant

The following table sets forth information regarding our eight executive officers, our directors and other key employees as of March 1, 2005.

Name	Age	Position
William J. Barrett	76	Chief Executive Officer, Chairman and Director
J. Frank Keller	61	Chief Operating Officer, Vice Chairman and Director
Fredrick J. Barrett	44	President and Director
Thomas B. Tyree, Jr	44	Chief Financial Officer
Robert W. Howard	50	Executive Vice President — Finance and Investor Relations, and Treasurer
Dominic J. Bazile II	46	Senior Vice President — Operations and Engineering
Francis B. Barron	42	Senior Vice President — General Counsel and Corporate Secretary

Huntington T. Walker	49	Vice President — Land
Terry R. Barrett	45	Vice President — Exploration, Northern Division
Lynn Boone Henry	44	Vice President—Reservoir Engineering
Kurt M. Reinecke	46	Vice President — Exploration, Southern Division
Wilfred R. Roux	47	Vice President — Geophysics
Duane J. Zavadil	45	Vice President—Government and Regulatory Affairs
Richard Aube	36	Director
Henry Cornell	48	Director
James M. Fitzgibbons	70	Director
Jeffrey A. Harris	49	Director
Roger L. Jarvis	51	Director
Philippe S. E. Schreiber	64	Director
Randy Stein	51	Director
Michael E. Wiley	54	Director

Each of William J. Barrett, Fredrick J. Barrett and J. Frank Keller may be deemed to be a promoter and founder of the Company due to his initiative in organizing the Company. William J. Barrett is the father of Fredrick J. Barrett and Terry R. Barrett and the brother-in-law of J. Frank Keller.

Executive Officers and Other Key Employees

William J. Barrett. Mr. Barrett has served as our Chairman of the Board, Chief Executive Officer and a Director since our inception in January 2002. Mr. Barrett founded Barrett Resources Corporation ("Barrett Resources"), which was acquired in August 2001 by The Williams Companies. Mr. Barrett served as the Chief Executive Officer of Barrett Resources from December 1983 until November 18, 1999, except for the period from July 1, 1997 through March 23, 1998. He also served Barrett Resources as Chairman of the Board from September 1994 until March 2000, and as President from December 1983 until September 1994. From March 2000 until November 2001, Mr. Barrett was retired. From November 2001 until the formation of the Company in January 2002, Mr. Barrett consulted on the establishment of the Company and its planned activities. Prior to 1983, Mr. Barrett held various positions with several other oil and gas companies.

J. Frank Keller. Mr. Keller has served as our Vice Chairman of the Board, Chief Operating Officer and a Director since our inception in January 2002. Mr. Keller was a co-founder of Barrett Resources and served as Barrett Resources' Executive Vice President from 1983 until Barrett Resources was acquired by The Williams Companies in August 2001. He also served as Chief Financial Officer of Barrett Resources from 1995 until July 2001, as a director from 1983 until 2000, and as Secretary from 1983 until 1997. From August 2001 until January 2002, Mr. Keller served as a consultant, including with respect to the establishment of the Company and its planned activities.

Fredrick J. Barrett. Mr. Barrett has served as our President and a Director since our inception in January 2002. Mr. Barrett served as senior geologist of Barrett Resources and its successor in the Rocky Mountain Region from 1997 through 2001, and as geologist from 1989 to 1996. From 1987 to 1989, Mr. Barrett was a partner in Terred Oil Company, a private oil and gas partnership providing geologic services for the Rocky Mountain Region. From 1983 to 1987, Mr. Barrett worked as a project and field geologist for Barrett Resources.

Thomas B. Tyree, Jr. Mr. Tyree has served as our Chief Financial Officer since February 2003. From August 1989 until January 2003, Mr. Tyree was employed by Goldman, Sachs & Co., most recently as a Managing Director in the Investment Banking Division, working with oil and gas companies. From 1983 to 1987, Mr. Tyree was employed by Bankers Trust Company as an Associate in corporate finance.

Robert W. Howard. Mr. Howard has served as our Executive Vice President — Finance and Investor Relations since January 2004 and as our Treasurer since our inception in January 2002. From February 2003 until January 2004, Mr. Howard served as our Executive Vice President — Finance and Accounting. From January 2002 until February 2003, Mr. Howard served as our Chief Financial Officer; from our inception in January 2002 until February 2004, Mr. Howard served as our Secretary; and from January 2002 until March 2002 he served as a Director of the Company. From August 2001 until December 2001, Mr. Howard served as Vice President — Finance and Administration and a director of AEC Oil & Gas (USA) Inc., an indirect subsidiary of Alberta Energy Company, Ltd., an oil and gas exploration and development company that subsequently was acquired by EnCana Corporation. Mr. Howard served as Senior Vice President — Investor Relations and Corporate Development of Barrett Resources from February 1999 until August 2001. Mr. Howard previously served as Barrett Resource's Senior Vice President beginning in March 1992 and as Treasurer beginning in March 1986.

Dominic J. Bazile II. Mr. Bazile has served as Senior Vice President — Operations and Engineering since May 2003 and previously served as our Vice President of Operations beginning in February 2002. Prior to joining us, Mr. Bazile was employed by Barrett Resources and its successor from July 1995 until January 2002, including serving as Drilling Manager.

Francis B. Barron. Mr. Barron has served as Senior Vice President — General Counsel and Secretary since March 2004. Mr. Barron was a partner at the Denver, Colorado office of Patton Boggs LLP from February 1999 until February 2004, practicing corporate, securities and general business law. Prior to February 1999, Mr. Barron was a partner of and served as an associate at Bearman Talesnick & Clowdus Professional Corporation, a Denver law firm. Mr. Barron's clients included publicly-traded oil and gas companies.

Huntington T. Walker. Mr. Walker has served as Vice President — Land since our inception in January 2002. From June 1981 through December 2001, Mr. Walker was self employed in the oil and gas industry as an independent landman performing consulting work for various clients including Barrett Resources and investing in oil and gas properties for his own account. From May 1979 through June 1981, Mr. Walker was employed by Hunt Energy Corporation in their Denver Office.

Terry R. Barrett. Mr. Barrett has served as Vice President — Exploration, Northern Division, since our inception in January 2002. From 1989 to 2001, Mr. Barrett served as Senior Geologist or Project Geologist in numerous Rocky Mountain basins for Barrett Resources Corporation, prior to the acquisition of that company by The Williams Companies. He served as Senior Geologist for approximately five months with The Williams Companies from August through December 2001. From 1987 to 1989, Mr. Barrett was a general partner in Terred Oil Company, a private oil and gas partnership providing geologic services for the Rocky Mountain Region. From 1983 to 1987, Mr. Barrett worked as a contract project and field geologist for Barrett Resources.

Lynn Boone Henry. Ms. Henry has served as Vice President—Reservoir Engineering since January 2005. From October 2003 until January 2005, Ms. Henry served as our Reservoir Engineering Manager. From January 2003 until October 2003, Ms. Henry served as the Senior Reservoir Engineer for our Wind River Basin team. From January 2002 until joining the Company in January 2003, Ms. Henry was an independent consultant on reservoir engineering projects for various Rocky Mountain exploration and production companies. From 1998 until 2002, Ms. Henry served as a Reserves Manager and Project Manager for Cody Energy, LLC in Denver.

Kurt M. Reinecke. Mr. Reinecke has served as Vice President — Exploration, Southern Division since our inception in January 2002. From 1985 to 2001, Mr. Reinecke served as a Senior Exploration Geologist or Operations Geologist in numerous Rocky Mountain and Mid-Continent basins for Barrett Resources Corporation, prior to the acquisition of that company by The Williams Companies.

Wilfred R. (Roy) Roux. Mr. Roux has served as Vice President — Geophysics since February 2002. Prior to joining us, Mr. Roux was employed by Barrett Resources and The Williams Companies from July 1995 until January 2002, including as Senior Geoscientist and Senior Geophysicist. Mr. Roux's responsibilities with us include overseeing our implementation and use of technology and geophysical data.

Duane J. Zavadil. Mr. Zavadil has served as Vice President — Government and Regulatory Affairs since January 2005. From the time that he joined the Company in July 2002 until January 2005, Mr. Zavadil served as our Government and Regulatory Affairs Manager. From 1994 until July 2002, Mr. Zavadil served as the Environmental, Health and Safety Manager with Barrett Resources Corporation and its successor, The Williams Companies. Mr. Zavadil was a consultant providing environmental and regulatory services to the oil and gas industry from 1984 through 1994.

Outside Directors

Richard Aube. Mr. Aube has served as a Director of the Company since October 2003. Mr. Aube is currently a Partner of JPMorgan Partners, LLC, a global private equity company affiliated with J.P. Morgan Chase & Co. Prior to joining JPMorgan Partners, LLC in 2000, Mr. Aube was a Partner of the Beacon Group for seven years. Prior to that, Mr. Aube worked as an investment banker in the Natural Resources Group at Morgan Stanley & Co., Incorporated. He currently serves as a director of other private companies.

Henry Cornell. Mr. Cornell has been a director of the Company since 2002. Mr. Cornell is a Managing Director in the Principal Investment Area of Goldman, Sachs & Co., which he joined in 1984. He is a member of the global Merchant Banking Investment Committees for both the firm's Corporate and Real Estate investment activities. Mr. Cornell also serves on the Board of Directors of Ping An Insurance Company of China and the American Golf Corporation, LLC.

James M. Fitzgibbons. Mr. Fitzgibbons has been a director since July 2004. Mr. Fitzgibbons also has served as a Director/Trustee of Dreyfus Laurel Funds, a series of mutual funds, since 1994. From January 1998 until 2001, Mr. Fitzgibbons served as Chairman of the Board of Davidson Cotton Company. From January 1994 until it was sold in August 2001, Mr. Fitzgibbons served as a director of Barrett Resources, for which he also served as a director from July 1987 until October 1992. From October 1990 through December 1997, Mr. Fitzgibbons was Chairman of the Board and Chief Executive Officer of Fieldcrest Cannon, Inc.

Jeffrey A. Harris. Mr. Harris has been a Director of the Company since 2002. Mr. Harris has served since 1988 as a Managing Director of Warburg Pincus LLC, which he joined in 1983. Mr. Harris' responsibilities include involvement in investments in energy, technology and other industries. Mr. Harris has served as a director of Spinnaker Exploration, Inc., a publicly traded oil and gas company, since 1996 and serves on Spinnaker's Compensation Committee. Mr. Harris also serves as a director of Proxim, Inc., a publicly traded provider of wireless networking equipment, since July 2003. Mr. Harris is a director of Knoll, Inc. and other private companies.

Roger L. Jarvis. Mr. Jarvis has been a Director of the Company since 2002. Mr. Jarvis has served as President, Chief Executive Officer and Director of Spinnaker Exploration Company since 1996 and as Chairman of the Board of Spinnaker since 1998. From 1986 to 1994, Mr. Jarvis served in various capacities with King Ranch Inc. and its subsidiary, King Ranch Oil and Gas, Inc., including Chief Executive Officer, President and Director of King Ranch Inc. and Chief Executive Officer and President of King Ranch Oil and Gas, Inc., where he expanded its activities in the Gulf of Mexico. Mr. Jarvis is a director of National-Oilwell, Inc.

Philippe S.E. Schreiber. Mr. Schreiber has been a Director of the Company since February 2002. Mr. Schreiber is an independent lawyer and business consultant. Mr. Schreiber served as a director of Barrett Resources from 1985 until 2001. From August 1985 through December 1998, he was a partner of, or of counsel to, the law firm of Walter, Conston, Alexander & Green, P.C. in New York, New York. Since 1991, Mr. Schreiber has served as a director of the United States principal affiliate of The Mayflower Corporation plc (in Administration), which was a publicly-listed company in the United Kingdom until it filed for creditor protection in April 2004. The United States affiliated companies of the Mayflower Corporation plc (in Administration) are not subject to any bankruptcy or creditor protection proceedings and Mr. Schreiber has not served as an officer or director of the Mayflower Corporation plc (in Administration). Mr. Schreiber also serves as a director of other private companies.

Randy Stein. Mr. Stein has served as a director and the chair of audit committee since July 2004. Mr. Stein is a self-employed tax and business consultant. From July 2000 until its sale in June 2004, Mr. Stein was a director of Westport Resources Corporation, a Denver based oil and natural gas exploration and development company, where Mr. Stein served as the chair of the Audit Committee. Mr. Stein has served since 2001 as a director of Koala Corporation, a Denver based public company engaged in the design, production and marketing of family convenience products, where he serves on the audit and compensation committees. Mr. Stein has served as a director and co-chairman of the audit committee of Denbury Resources Inc., a Dallas based, publicly traded, independent oil and gas company, since January 2005. He also was a principal at PricewaterhouseCoopers LLP, formerly Coopers & Lybrand LLP, from November 1986 to June 30, 2000.

Michael E. Wiley. Mr. Wiley has served as a director since January 2005. Mr. Wiley served as Chairman of the Board and Chief Executive Officer of Baker Hughes Incorporated, an oilfield services company, from August 2000 until October 2004. He also served as President of Baker Hughes from August 2000 to February 2004. Mr. Wiley was President and Chief Operating Officer of Atlantic Richfield Company, an integrated energy company, from 1998 through May 2000. Prior to 1998, he served as Chairman, President and Chief Executive Officer of Vastar Resources, Inc., an independent oil and gas company. Mr. Wiley is a director of Spinnaker Exploration and Post Oak Bank, NA, a trustee of the University of Tulsa and a member of the National Petroleum Council. He also serves on the Advisory Board of Riverstone Holdings LLC.

Management Philosophy

The Company is managed on a day-to-day basis by a team of eight executive officers that includes William J. Barrett, our Chief Executive Officer; J. Frank Keller, our Chief Operating Officer; Fredrick J. Barrett, our President; Thomas B. Tyree, Jr., our Chief Financial Officer; Robert W. Howard, our Executive Vice President — Finance and Investor Relations; Dominic J. Bazile II, our Senior Vice President — Operations and Engineering; Francis B. Barron, our Senior Vice President — General Counsel; and Huntington T. Walker, our Vice President — Land. Our executive management team meets formally on a weekly basis and informally on a daily basis. Interaction among the executive officers is intense, candid and highly cooperative, reflecting a team-oriented management philosophy that defines the culture of our company. All of our executive officers successfully worked together, as officers and advisors, for many years with Barrett Resources and now with Bill Barrett Corporation.

Our Chief Executive Officer, William J. Barrett, continues to actively manage the operations of our company. Our Chief Operating Officer, President, Chief Financial Officer and General Counsel report directly to Mr. Barrett. Our President, Fredrick J. Barrett, manages the exploration side of our business, which includes seven dedicated, multi-functional basin teams, as well as our Geophysics and Information Technology teams. Each of our basin teams — Wind River, Uinta, Piceance, Powder River, Williston, Tri-State and Paradox — is led by a senior manager with extensive experience in his respective region of operations. Our basin team leaders manage their regions as separate business units, with responsibility for exploration, production, land, acquisitions, capital budgeting, and other functions relevant to their respective regions, including the continuing generation of new geologic play concepts. Each team works very closely with our Operations Department, which is managed by our Chief Operating Officer, J. Frank Keller. Our basin teams are directly accountable for the performance of their respective basins, which is measured based on production, cash flow, cost structure, exploration and development success and other factors.

Our executive officers and board of directors view our employees as our greatest asset, and recognize the importance of identifying talented individuals and preparing them for senior management positions. An executive development plan has been formulated and implemented, which provides increasing levels of responsibility and training for those employees who could ultimately succeed to senior management positions within our company. Several individuals have been identified and are being developed as candidates for various of our executive positions. In addition to these internal candidates, the board and management, as a matter of course, monitor other individuals within as well as outside of our company.

Board of Directors

We currently have 11 directors. Our restated certificate of incorporation and bylaws provide for a classified board of directors consisting of three classes of directors, each serving staggered three-year terms. As a result, stockholders will elect a portion of our board of directors each year. Class I directors' terms will expire at the annual meeting of stockholders to be held in 2005, Class II directors' terms will expire at the annual meeting of stockholders to be held in 2006 and Class III directors' terms will expire at the annual meeting of stockholders to be held in 2007. The Class I directors are Messrs. Aube, Cornell and Keller, the Class II directors are Messrs. Fredrick Barrett, Harris, Stein and Wiley, and the Class III directors are Messrs. William Barrett, Fitzgibbons, Jarvis and Schreiber. At each annual meeting of stockholders held after the initial classification, the successors to directors whose terms will then expire will be elected to serve from the time of election until the third annual meeting following election. The division of our board of directors into three classes with staggered terms may delay or prevent a change of our management or a change in control.

In addition, our restated bylaws provide that the authorized number of directors, which shall constitute the whole board of directors, may be changed by a resolution duly adopted by the board of directors. Any additional directorships resulting from an increase in the number of directors will be distributed among the three classes so that, as nearly as possible, each class will consist of one-third of the total number of directors. Vacancies and newly created directorships may be filled by the affirmative vote of a majority of our directors then in office, even if less than a quorum.

Each of our current directors were nominated in accordance with provisions of a stockholders' agreement entered into at the time of the initial Series B preferred stock investment. These stockholders' agreement provisions automatically terminated upon the closing of our initial public offering.

Committees of the Board

Our board of directors currently has an audit committee, a compensation committee and a nominating and corporate governance committee.

Audit Committee. As of March 11, 2005, our audit committee consisted of Messrs. Stein, Fitzgibbons and Schreiber. Messrs. Stein, Fitzgibbons and Schreiber are "independent" under the standards of the New York Stock Exchange and SEC regulations. In addition, the board of directors has determined that Mr. Stein is an "audit committee financial expert", as defined under the rules of the SEC. As required by the standards of the New York Stock Exchange, the audit committee consists solely of independent directors. Our audit committee operates pursuant to a formal written charter. This committee oversees, reviews, acts on and reports to our board of directors on various auditing and accounting matters including: the selection of our independent accountants, the scope of our annual audits, fees to be paid to the independent accountants, the performance of our independent accountants, our accounting practices, and the selection and performance of personnel performing our internal audit function. In addition, the audit committee oversees our compliance programs relating to legal and regulatory requirements.

Compensation Committee. As of March 11, 2005, our compensation committee consisted of Messrs. Fitzgibbons, Harris, Jarvis, Schreiber, and Wiley, each of whom is "independent" under the standards of the New York Stock Exchange and SEC regulations. As required by the standards of the New York Stock Exchange, the compensation committee consists solely of independent directors. Our compensation committee operates pursuant to a formal written charter. This committee establishes salaries, incentives and other forms of compensation for officers and other employees. Our compensation committee also administers our incentive compensation and benefit plans.

Nominating and Corporate Governance Committee. As of March 11, 2005, our nominating and corporate governance committee consisted of Messrs. Cornell, Harris, Jarvis, and Wiley each of whom is "independent" under the standards of the New

York Stock Exchange and SEC regulations. Our nominating and corporate governance committee operates pursuant to a formal written charter. This committee identifies, evaluates and recommends qualified nominees to serve on our board of directors, develops and oversees our internal corporate governance processes and maintains a management succession plan.

Section 16(A) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), requires our directors and executive officers, and persons who own more than ten percent of a registered class of our equity securities, to file with the Commission and any exchange or other system on which such securities are traded or quoted, initial reports of ownership and reports of changes in ownership of common shares and other equity securities of the Corporation.

To our knowledge, based solely on a review of the copies of such reports furnished to us and written representations that no other reports were required, we believe that all reporting obligations of our officers, directors and greater than 10% shareholders under Section 16(a) were satisfied during the year ended December 31, 2004.

Code of Ethics

We maintain a Code of Ethics and Business Conduct, which includes our code of ethics for senior financial management. The Code of Ethics and Business Conduct is posted on our website, www.billbarrettcorp.com. See "Item 1. Business and Properties – Website and Code of Business Conduct".

Item 11. Executive Compensation

Summary Compensation Table

The following table sets forth the compensation since our inception of our chief executive officer and each of our other four most highly compensated executive officers serving as of December 31, 2004 (we refer to these five individuals, collectively, as the named executive officers) for the fiscal years ended December 31, 2004, 2003 and 2002.

			Annual Compensation		Long-Term Compensation Awards	
Name and Principal Position	**Year**	**Salary**	**Bonus**	**Other Annual Compensation**	**Securities Underlying Options/SARs (#)(1)**	**All Other Compensation (3)**
William J. Barrett	2004	$ 263,755	$ 267,500	$ —	100,000	$ —
Chief Executive Officer	2003	237,500	100,000	—	—	—
	2002	181,250	75,000	118,400(2)	231,330	—
J. Frank Keller	2004	$ 215,625	$ 125,000	$ —	50,000	$ 8,572
Chief Operating Officer	2003	201,250	75,000	—	—	8,870
	2002	165,625	58,000	51,800(2)	129,889	583
Fredrick J. Barrett	2004	$ 199,905	$ 125,000	$ —	50,000	$ 6,218
President	2003	154,700	75,000	—	—	5,768
	2002	128,750	37,000	22,200(2)	76,483	467
Thomas B. Tyree, Jr.	2004	$ 209,375	$ 125,000	$ —	50,000	$ 6,575
Chief Financial Officer	2003	183,333	75,000	510,288(4)	246,896	6,000
	2002	—	—	—	—	—
Francis B. Barron	2004	$ 174,762	$115,000(5)	$ 24,160(6)	43,248	$ 5,748
Senior Vice President—	2003	—	—	—	—	—
General Counsel; and Secretary	2002	—	—	—	—	—

(1) A portion of these options have been amended as described below in "— Equity Compensation Plan Information — 2002 Stock Option Plan — Amendment of Tranche A Options".

(2) Consists of the difference between the purchase price for shares of common stock purchased by the named executive officer and the fair market value of those shares on the date of purchase. For additional information concerning the vesting of shares of common stock purchased by management, see "Item 13. Certain Relationships and Related Transactions—Investments in the Company".

(3) Consists of 401(k) plan matching contributions.

(4) Consists of $17,648, which was the difference between the purchase price for shares of common stock purchased by Mr. Tyree and the fair market value of those shares, $300,000 for relocation expenses (including travel expenses to search for a house in Colorado, moving expenses, brokerage commissions, real estate transfer taxes and legal fees related to the sale of Mr. Tyree's residence, and the cost of temporary housing), $15,000 for legal expenses relating to the commencement of employment (including for the negotiation of Mr. Tyree's terms of employment with us and the terms of his separation from his previous employer), and $177,640 for the reimbursement of income taxes related to expense payments.

(5) Includes $30,000 paid in the form of a restricted stock grant of 917 shares of common stock at $32.70 per share pursuant to our 2004 Stock Incentive Plan. These shares vest 25% on each of March 9, 2006, 2007, 2008 and 2009 if Mr. Barron continues as an employee on those dates.

(6) Consists of the difference between the purchase price for Series B preferred stock purchased by Mr. Barron and the fair market value of those shares.

Stock Options Granted During 2004

The following table sets forth certain information regarding stock options granted to the named executive officers as of December 31, 2004.

	Individual Grants				Potential Realizable Value at Assumed Annual Rates of Stock Price Appreciation for Option Term	
Name	Number of Securities Underlying Options/ SARs Granted (#)(1)	Percentage of Total Options/ SARs Granted to Employees in Fiscal Year	Exercise Or Base Price ($/Sh)	Expiration Date	5% ($)	10% ($)
William J. Barrett	100,000	9%	$ 25.00	12/9/2011	$ 1,018,221	$ 2,373,065
J. Frank Keller	50,000	4%	25.00	12/9/2011	$ 509,111	$ 1,186,533
Fredrick J. Barrett	50,000	4%	25.00	12/9/2011	$ 509,111	$ 1,186,533
Thomas B. Tyree, Jr.	50,000	4%	25.00	12/9/2011	$ 509,111	$ 1,186,533
Francis B. Barron	43,248	4%	2.14-25.00	03/4/2013	$ 255,530	$ 616,452

(1) Excludes options that were exchanged when we allowed the holders of all outstanding options with an exercise price of $30.28 per share, including the named executive officers, to amend those options to provide for an exercise price equal to the price to the public in our initial public offering of $25.00 in December 2004, to decrease the number of shares subject to the options and to reduce the expiration date until December 9, 2011. See "— Equity Compensation Plan Information — 2002 Stock Option Plan — Amendment of Tranche A Options".

Aggregated Option Exercises During 2004
and Option Values at December 31, 2004

The following table sets forth certain information regarding options that the named executive officers exercised during 2004 and the options that those persons held at December 31, 2004.

Name	Shares Acquired on Exercise (#)	Value Realized ($)	Number of Securities Underlying Unexercised Options/SARs at FY-End (#)(1)		Value of Unexercised In-the-Money Options/SARs at FY-End ($)	
			Exercisable	Unexercisable	Exercisable	Unexercisable
William J. Barrett	8,695	105,442	104,372	186,972	$ 729,560	$ 1,734,537
J. Frank Keller	4,509	56,374	59,641	98,778	$ 416,891	$ 912,177
Fredrick J. Barrett	2,415	42,475	35,785	78,686	$ 250,137	$ 668,780
Thomas B. Tyree, Jr.	55,820	107,058	39,761	193,371	$ 277,929	$ 3,410,499
Francis B. Barron	-	-	-	42,692	$ -	$ 530,269

(1) We allowed the holders of all outstanding options with an exercise price of $30.28 per share, including the named executive officers, to amend those options to provide for an exercise price equal to the initial public offering price of $25.00, to decrease the number of shares subject to the options and to reduce the termination date of the options to the seventh anniversary of the closing of the initial public offering and all holders, including the named executive officers, agreed to this amendment. See "— Equity Compensation Plan Information — 2002 Stock Option Plan — Amendment of Tranche A Options".

Compensation Committee Interlocks and Insider Participation

The compensation committee consists of Messrs. Fitzgibbons, Harris, Jarvis and Schreiber, all of whom are non-employee directors. None of these individuals has ever been an officer or employee for our company. In addition, none of our executive officers serve as a member of a board of directors or compensation committee of any entity that has one or more executive officers who serve on our board or on our compensation committee.

Director Compensation

Our directors who are not employees of the Company and who were not previously nominated by the investors in our Series B preferred stock ("Outside Directors") receive an annual retainer of $25,000 and a meeting attendance fee of $1,000 for each board and committee meeting attended. The chair of the audit committee receives an additional annual retainer of $15,000, the chair of the compensation committee receives an additional annual retainer of $10,000, and the chairs of other committees receive an additional annual retainer of $5,000. In July 2004, our Compensation Committee determined that the Outside Directors should receive equity compensation under our 2004 Stock Incentive Plan with a value at the date of award or grant of approximately $80,000 per year in the form of stock options, restricted stock and/or other equity grants. In July 2004, the Compensation Committee determined that the first grant to Outside Directors would be in the form of options to purchase 10,000 shares of common stock effective upon the completion of our initial public offering with an exercise price equal to the price to the public in the initial public offering. The number of shares underlying the options was based on the estimated initial public offering price at that time. When the initial public offering price, and therefore the Black Scholes value of the 10,000 options, increased, the Committee did not reduce the number of options granted upon the completion of the initial public offering. When Mr. Wiley was elected as an Outside Director in January 2005, the Compensation Committee approved granting him options to purchase 10,000 shares of common stock at an exercise price equal to the closing sales price on the New York Stock Exchange on the last trading day prior to his election in accordance with the 2004 Stock Incentive Plan. All these options vest 25% on each of the first four anniversaries of the date of grant, and terminate on the seventh anniversary of the date of grant. All directors are reimbursed for all reasonable out-of-pocket expenses incurred in attending meetings of the board of directors.

Employment Agreements

Our only employment agreement with an executive officer is an agreement with Thomas B. Tyree, Jr., our Chief Financial Officer, effective February 4, 2003. The agreement provides for a base annual salary of at least $200,000 per year, subject to annual review by the board of directors, reimbursement for reasonable relocation expenses not to exceed $300,000 and legal expenses related to the commencement of his employment and for income taxes related to those expense reimbursements, plus an opportunity to participate in any programs, including cash bonus programs, made available to senior executives. Pursuant to the agreement, Mr. Tyree purchased 200,000 shares of fully vested Series B preferred stock on July 1, 2003 for $1,000,000. In addition, pursuant to the agreement, Mr. Tyree was granted on February 3, 2003 ("Date of Grant") incentive stock options to purchase (1) up to 107,346 shares of common stock at an exercise price of $30.28 per share (the "Tranche A Options") and (2) up to 139,550 shares of common stock at an exercise price of $0.41 per share (the "Tranche B Options"). Twenty percent of each of the Tranche A and the Tranche B options were exercisable on the Date of Grant, with an additional 20% becoming exercisable on each of the first, second, third and fourth anniversaries of the Date of Grant, if Mr. Tyree continues to be an employee on each such date. Mr. Tyree also purchased from William J. Barrett 85,877 shares of common stock at $0.21 per share on July 1, 2003, with 40% vested at purchase and an additional 20% vesting on January 31 of 2004, 2005 and 2006, which is the same vesting schedule as shares held by other members of management. Mr. Tyree's employment agreement further provided that he would not be terminated prior to July 31, 2004 other than for cause, and if his employment agreement is terminated after July 31, 2004 without cause, he is entitled to a severance payment equal to the amount provided under any applicable severance plan. In October 2004, we agreed to allow all holders of Tranche A Options, including Mr. Tyree, to amend their Tranche A Options as described below in "— Description of Benefit Plans — 2002 Stock Option Plan — Amendment of Tranche A Options".

Change in Control Severance Protection Agreements

In July 2004, our board of directors approved severance agreements for the named executive officers and other employees in the event that there is both a change in control (as defined in the agreements) of the Company and the person's employment is terminated within one year after the change in control other than a termination for cause or without good reason, as defined in the agreement. The named executive officers are entitled to receive a severance payment equal to two times their highest cash compensation, including bonus, during any consecutive 12 month period in the three years preceding the termination. This amount is payable in a lump sum. Each named executive officer also is entitled to accelerated vesting of all unvested stock options and accelerated lapsing of all restrictions on restricted stock grants upon the occurrence of the change in control, regardless of whether the named executive officer is terminated. Each named executive officer also will receive continuation of all life, disability, accident and health insurance for 36 months after termination, or reasonably equivalent benefits, as well as outplacement services to assist in obtaining new employment. Each agreement automatically expires if a change in control has not occurred within a 10-year period, and may be renewed for successive one-year periods by written agreement of the parties.

Indemnification Agreements

We have entered into an indemnification agreement with each of our directors and executive officers. These agreements require us, among other things, to indemnify our directors and officers against certain liabilities that may arise by reason of their status or service as directors or officers, to advance their expenses incurred as a result of a proceeding as to which they may be indemnified, and to cover them under any directors' and officers' liability insurance policy we choose, in our discretion, to maintain. These indemnification agreements are intended to provide indemnification rights to the fullest extent permitted under applicable indemnification rights statutes in the State of Delaware and will be in addition to any other rights that the indemnitee may have under our restated certificate of incorporation, bylaws and applicable law.

Severance Plan

Our board of directors has adopted a Severance Plan, effective as of July 1, 2004. The purpose of the Severance Plan is to provide an incentive to our employees who are not covered by severance protection agreements to continue to work for us for specified periods following a change in control (as defined in the plan). The Severance Plan may be amended or terminated by our board of directors at any time prior to the occurrence of an event intended to cause a change in control.

Pursuant to the Severance Plan, all full-time regular employees who have at least six months service with us prior to the date of a change in control and are not covered by a severance protection agreement are eligible to receive certain severance benefits. Employees not hired on a full-time basis and employees with individual agreements providing similar severance benefits are not eligible to participate in the Severance Plan. If an eligible employee's employment is terminated (i) by us without cause or (ii) by such employee with cause, such employee will receive the greater of three weeks of base salary multiplied by the employee's years of service or three weeks of base salary for each $10,000 of annual base salary. The minimum severance payment shall be equal to 12 weeks' base salary. The maximum severance payment will not exceed 26 weeks' base. The Severance Program also provides for certain medical benefits to continue for six months after termination and for accelerated vesting of stock options and restricted stock grants. No employee will receive severance benefits unless he or she executes a release of all claims against us in a form acceptable to us.

Description of Benefit Plans

2002 Stock Option Plan

General. Our Amended and Restated 2002 Stock Option Plan (the "2002 Option Plan"), was adopted by our board of directors and subsequently approved by our stockholders so that incentive stock options may be granted under the 2002 Option Plan. Pursuant to the exercise of options granted under the 2002 Option Plan, we may issue up to 1,642,395 shares of common stock, either treasury or authorized but unissued, to key employees, directors and other persons who have contributed or are contributing to our success. Unissued shares that are subject to an option, which for any reason expires or otherwise terminates before exercise, may again be made subject to options under the 2002 Option Plan. No one person may be granted during any two-year period options to purchase more than 279,100 shares. As of December 31, 2004, options to purchase 1,552,621 shares have been granted pursuant to the 2002 Option Plan so that options to purchase an additional 89,774 shares may be granted under the 2002 Option Plan. The 2002 Option Plan will terminate at midnight on January 10, 2012, except as to options previously granted and outstanding at that time. In addition, the 2002 Option Plan may be amended by the board of directors (provided that no amendment generally may impair any option then outstanding) and may be terminated at any earlier time by the board of directors (except with respect to any options then outstanding).

Administration. The 2002 Option Plan is administered by an option committee composed of our board of directors or by a committee of at least two directors selected by our board of directors. The compensation committee is serving as the option committee. Administration of the 2002 Option Plan includes selection of optionees and determination of the terms of options granted under the 2002 Option Plan. In addition, the option committee may adopt such rules and regulations for carrying out the purposes of the 2002 Option Plan as it deems proper and in our best interests.

Options. We agreed with our initial investors that, during the period that the stockholders agreement with our initial investors was in effect, options (the "Tranche A Options") to purchase up to 1,180,807 shares may be granted with an exercise price of $30.28 or more per share and options to purchase an additional 461,588 shares may be granted with an exercise price of not less than $0.21 per share. The stockholders agreement terminated on December 15, 2004 upon the completion of our initial public offering, except as to limited matters. As part of the amendment of Tranche A Options described below under "— Amendment of Tranche A Options", the investors agreed to amend the 2002 Option Plan to allow the decrease of the minimum exercise price for Tranche A Options to the initial public offering price. The option committee determines the exercise price for options granted under the 2002 Option Plan; provided that the exercise price for shares underlying incentive options will be fixed and will not be less than 100% of the fair market value (as defined in the plan) of the option shares on the date of grant. The option period begins on the date of grant and may continue for a period designated by the option committee up to a maximum of ten years from the date of grant. Each option granted on or before February 3, 2003 was exercisable with respect to 20% of the option shares on the date of grant and an additional 20% became exercisable on the first four anniversaries of the date of grant if the optionee continued to be employed by the Company on those dates. Options granted after February 3, 2003 are exercisable with respect to 40% of the option shares upon the first anniversary of the date of grant, 60% upon the second anniversary of the date of grant, 80% upon the third anniversary of the date of grant and 100% upon the fourth anniversary of the date of grant; provided the optionee continues to be employed by the Company on those dates. The date on which all or a portion of an option may be exercised may be accelerated upon a change in control (as described in the 2002 Option Plan). In addition, upon a change in control, the option committee may allow for the surrender of options in exchange for the excess of the per share consideration received in the change in control transaction over the option exercise price and may cancel any options not exercised or surrendered in connection with the change in control. The exercise price generally will be paid in cash or, if permitted by the option committee, in common stock previously owned by the optionee. Options granted under the 2002 Option Plan are not transferable except by will, the applicable laws of descent and distribution, or, in the case of non-qualified options, (1) pursuant to a domestic relations order or (2) with the committee's consent, to certain permitted transferees. We may withhold from any compensation or other payments due to the optionee amounts as may be necessary to satisfy any withholding requirements of federal or state law or regulation, otherwise require the optionee to remit such amount to us, or provide for an optionee to satisfy his or her tax withholding obligations by our retention or receipt of common stock. In the event that each of the outstanding shares of common stock should be changed into, or exchanged for, a different number or kind of our shares of stock or other securities, or if further changes or exchanges of any stock or other securities into which the common stock has been changed, or exchanged, is made (whether by reason of merger, consolidation, reorganization, recapitalization, stock dividends, reclassification, split-up, combination of shares or otherwise), then there will be substituted for each share of common stock that is subject to the 2002 Option Plan, the number and kind of shares of stock or other securities into which each outstanding share of common stock will be so changed or exchanged. In addition, in the event of any such change or exchange, the option committee may adjust the number, kind and exercise price of outstanding options under the 2002 Option Plan.

Amendment of Tranche A Options. We allowed the holders of all 1,178,235 outstanding Tranche A Options to amend those options to provide that each option to purchase one share of common stock for $30.28 per share became an option to purchase a number of shares of common stock at the initial public offering price that had an estimated value that is equivalent to the estimated value of the outstanding Tranche A Options. The exact ratio was determined by comparing the relative estimated value of the outstanding Tranche A Options based on the original exercise price and weighted average remaining terms to the estimated value based on the initial public offering price using the Black-Scholes option pricing model. Based on the initial offering price of $25.00 per share, the ratio was 0.926 so that each existing Tranche A Option to purchase one share of common stock at $30.28 per share became an option to purchase 0.926 shares at $25.00 per share. In addition, the modified options have a term of seven years after the completion of our initial public offering compared to the weighted average remaining term of the Tranche A Options of approximately eight years. The vesting schedules for the Tranche A Options will not change. We allowed the amendment of the Tranche A Options because we believed the $30.28 per share exercise price did not provide sufficient incentive compared to the initial public offering price and we believed the amendment could provide incentive while not changing the relative estimated value of the options before the amendment and the estimated value of the reduced number of options after the amendment.

2003 Stock Option Plan

General. Our 2003 Stock Option Plan (the "2003 Option Plan") was adopted by our board of directors and approved by our stockholders so that incentive stock options may be granted under the 2003 Option Plan. Pursuant to the exercise of options granted under the 2003 Option Plan, we may issue up to 42,938 shares of common stock, either treasury or authorized but unissued, to our key employees, directors and other persons who have contributed or are contributing to our success. Unissued shares that are subject to an option, which for any reason expires or otherwise terminates before exercise, may again be made subject to options under the 2003 Option Plan. No one person may be granted during any two-year period options to purchase more than 21,468 shares. As of December 31, 2004, options to purchase 42,936 shares have been granted pursuant to the 2003 Option Plan so that two additional options may be granted under the 2003 Option Plan. The 2003 Option Plan will terminate at midnight on December 10, 2013, except as to options previously granted and outstanding under the 2003 Option Plan at that time. In addition, the 2003 Option Plan may be amended by the board of directors (provided that no such amendment generally may impair any option then outstanding) and may be terminated at any earlier time by the board of directors (except with respect to any options then outstanding).

Administration. The 2003 Option Plan is administered by an option committee composed of our board of directors or by a committee of at least two directors selected by our board of directors. The compensation committee serves as the option committee. Administration of the 2003 Option Plan includes selection of optionees and determination of the terms of options granted under the 2003 Option Plan. In addition, the option committee may adopt such rules and regulations for carrying out the purposes of the 2003 Option Plan as it deems proper and in our best interests.

Options. The option committee will determine the exercise price for options granted under the 2003 Option Plan; provided that the exercise price for shares underlying incentive options will be fixed and will not be less than 100% of the fair market value (as defined in the plan) of the option shares on the date of grant. The option period begins on the date of grant and may continue for a period designated by the option committee up to a maximum of ten years from the date of grant. Options granted are exercisable with respect to 25% of the option shares upon the first anniversary of the date of grant, 50% upon the second anniversary of the date of grant, 75% upon the third anniversary of the date of grant and 100% upon the fourth anniversary of the date of grant; provided the optionee continues to be employed by us on those dates. The date on which all or a portion of an option may be exercised may be accelerated upon a change in control (as described in the 2003 Option Plan). In addition, upon a change in control, the option committee may allow for the surrender of options in exchange for the excess of the per share consideration received in the change in control transaction over the option exercise price and may cancel any options not exercised or surrendered in connection with the change in control. The exercise price generally will be paid in cash or, if permitted by the option committee, in common stock previously owned by the optionee. Options granted under the 2003 Option Plan are not transferable except by will, the applicable laws of descent and distribution, or, in the case of non-qualified options, (1) pursuant to a domestic relations order or (2) with the committee's consent, to certain permitted transferees. The option committee is entitled to withhold from any compensation or other payments due to the optionee amounts as may be necessary to satisfy any withholding requirements of federal or state law or regulation, otherwise require the optionee to remit such amount to us, or provide for an optionee to satisfy his or her tax withholding obligations by our retention or receipt of common stock. In the event that each of the outstanding shares of common stock should be changed into, or exchanged for, a different number or kind of our shares of stock or other securities, or if further changes or exchanges of any stock or other securities into which the common stock has been changed, or exchanged, is made (whether by reason of merger, consolidation, reorganization, recapitalization, stock dividends, reclassification, split-up, combination of shares or otherwise), then there will be substituted for each share of common stock that is subject to the 2003 Option Plan, the number and kind of shares of stock or other securities into which each outstanding share of common stock will be so changed or exchanged. In addition, in the event of any such change or exchange, the option committee may adjust the number, kind and exercise price of outstanding options under the 2003 Option Plan.

2004 Stock Incentive Plan

General. Our 2004 Stock Incentive Plan (the "2004 Incentive Plan") was adopted by our board of directors and will be submitted for approval by our stockholders. The purpose of the 2004 Incentive Plan is to enhance our ability to attract and retain officers, employees, directors and consultants and to provide such persons with an interest in the Company parallel to our stockholders. The 2004 Incentive Plan provides for the grant of stock options (including incentive stock options, as defined in Section 422 of the Code, and non-qualified stock options) and other awards (including performance units, performance shares, share awards, restricted stock, restricted stock units, and stock appreciation rights, or SARs). The maximum number of shares that may be made the subject of options and awards granted under the 2004 Incentive Plan is 4,900,000, all of which may be made the subject of either restricted stock awards or restricted stock units or may be issued upon the exercise of incentive stock options. In addition, the maximum number of shares that may be the subject of options and awards granted to a participant in any one year is 1,225,000. As of December 31, 2004, options to purchase 1,074,000 shares had been granted pursuant to the 2004 Incentive Plan so that additional awards covering 3,826,000 shares may be granted under the 2004 Incentive Plan. Unless terminated earlier by our board of directors, the 2004 Incentive Plan will terminate on June 30, 2014. Upon an event constituting a "change in control" (as defined in the 2004 Incentive Plan) of the Company, all options and SARs will become immediately exercisable in full. In addition, in such an event performance units will become immediately vested and restrictions on stock granted pursuant to restricted stock awards and restricted stock units will lapse.

Administration. The 2004 Incentive Plan is administered by an option committee appointed by our board of directors, constituted so as to comply with Rule 16b-3 under the Exchange Act, and comprised of two or more "outside directors" (within the meaning of Section 162(m) of the Internal Revenue Code). The compensation committee is serving as the option committee. Our compensation committee may grant options and SARs on such terms, including vesting and payment forms, as it deems appropriate in its discretion, however, no option or SAR may be exercised more than 10 years after its grant, and the purchase price for incentive stock options may not be less than 100% of the fair market value of our common stock on the date of grant. Our compensation committee may grant restricted stock awards, restricted stock units, share awards, performance units and performance shares on such terms and conditions as it may in its discretion decide.

Options. The purchase price or the manner in which the exercise price is to be determined for shares under each option will be determined by the compensation committee and set forth in the agreement. However, the exercise price per share under each incentive stock option may not be less than 100% of the fair market value of a share on the date the option is granted (110% in the case of an incentive stock option granted to an eligible individual who possesses more than 10% of the total combined voting power of all classes of stock of the Company). Each option will become exercisable in such installments and at such times as the compensation committee designates and sets forth in the agreement. The compensation committee will determine the term of the options, provided that an incentive stock option will not be exercised after the expiration of ten years from the date it was granted (five years in the case of an incentive stock option granted to an individual who possesses more than 10% of the total combined voting power of all classes of stock of the Company). Rights under any option may not be transferred except by will or the laws of descent and distribution. The compensation committee, however, may provide that the option may be transferred to members of the optionee's immediate family or to trusts, partnerships or limited liability companies established solely for the benefit of such immediate family members.

Restricted Common Stock. The compensation committee may grant awards of restricted stock to eligible individuals, which will be evidenced by an agreement between the Company and the grantee setting out the applicable restrictions on, and terms and conditions of, the restricted stock. Shares of restricted stock may not be sold, assigned, transferred, pledged or disposed of for a restricted period of time as the compensation committee may determine. Unless otherwise determined by the compensation committee, upon termination of a plan participant from the Company prior to the end of the restricted period, the restricted stock shall be forfeited. The compensation committee may also award eligible individuals restricted stock units having a value equal to an identical number of shares of common stock. Payment for restricted stock units is made in common stock or in cash or a combination thereof as determined by the compensation committee.

Performance Shares. The compensation committee may grant awards of performance shares in the form of actual shares of common stock or common stock units having a value equal to an identical number of shares of common stock. The compensation committee shall establish the performance objective for each award of performance shares, consisting of one or more business criteria, one or more levels of performance with respect to each such criteria, and the amount or amounts payable or other rights that the participant will be entitled to upon achievement of such levels of performance. Performance objectives shall be objective and shall meet the requirements of Section 162(m) of the Code. Performance objectives may differ for performance shares granted to any one participant or to different participants. An award of performance shares to a participant who is also a covered employee shall, unless the compensation committee determines otherwise, provide that in the event of the participant's termination of service prior to the end of the performance period for any reason, such award will be payable only (i) if the applicable performance objectives are achieved and (ii) to the extent the compensation committee determines. Following the completion of each performance period, the compensation committee shall certify in writing, in accordance with 162(m) of the Code, whether the performance objectives and other material terms of an award have been achieved or met. The compensation committee may in its discretion reduce or eliminate the amount of payment with respect to an award to a covered employee, notwithstanding the achievement of the specified objectives, however no adjustment shall be made which would adversely impact a participant following a change of control. The maximum number of performance shares subject to any award to a covered employee is 1,225,000 for each 12 months during the performance period.

Share Purchases. The compensation committee may authorize eligible individuals to purchase common stock in the Company at a price equal to, below or above the fair market value of the common stock at the time of grant. Any such offer may be subject to the conditions and terms of the compensation committee may impose.

Stock Appreciation Rights (SARs). SARs may be granted by the compensation committee, in its discretion, in connection with or independently of an option, common stock or SAR. A SAR granted in connection with an option is generally subject to the same terms and conditions with respect to exercisability and transfer applicable to the particular option grant to which it pertains. Upon exercise of a SAR related to an option, the participant shall be entitled to receive an amount determined by multiplying (1) the excess of the fair market value of a share of common stock on the date preceding the date of exercise of such SAR over the per share purchase price under the related option, by (2) the number of shares of common stock as to which such SAR is being exercised. Upon the exercise of a SAR granted in connection with an option, the option shall be canceled to the extent of the number of shares of common stock as to which the SAR is exercised, and upon the exercise of an option granted in connection with a SAR, the SAR shall be canceled to the extent of the number of shares of common stock as to which the option is exercised or surrendered. SARs unrelated to options shall contain such terms and conditions as to exercisability, vesting and duration as the compensation committee shall determine, but in no event shall they have a term of greater than ten (10) years. Upon exercise of a SAR unrelated to an option, the participant shall be entitled to receive an amount determined by multiplying (1) the excess of the fair market value of a share on the date preceding the date of exercise of such SAR over the per share exercise price of the SAR, by (2) number of shares as to which the SAR is being exercised. To exercise any outstanding SAR, the participant shall provide written notice of exercise to the Company. Payment to the participant may be made in the discretion of the compensation committee solely in whole shares of common stock in a number determined at their fair market value on the date preceding the date of exercise of the SAR, or solely in cash, or in a combination of cash and shares of common stock. If the compensation committee decides to make full payment in shares of common stock and the amount payable results in a fractional share, payment for the fractional share will be made in cash.

Share Awards. Subject to performance conditions as the Committee may determine, awards of common stock or awards based on the value of the common stock may be granted either alone or in addition to other awards granted under the plan. Payment of common stock awards that are based on the value of common stock may be made in common stock, or in cash or in a combination thereof as determined by the compensation committee.

Item 12. Security Ownership of Certain Beneficial Owners and Management

The following table sets forth, as of March 1, 2005, certain information with respect to ownership of our common shares as to (a) all persons known by us to be the beneficial owners of more than five percent of our outstanding common shares, (b) each director, (c) each nominee for director, (d) each of the executive officers named in the Summary Compensation Table, and (e) all executive officers and directors of the Corporation as a group. To our knowledge, and based on a review of public filings made with the Securities and Exchange Commission (the "Commission") as of March 1, 2005, we did not have any beneficial owners of more than five percent of our common shares, other than those listed below.

Unless otherwise indicated in the footnotes to this table and subject to community property laws where applicable, we believe that each of the stockholders named in this table has sole voting and investment power with respect to the shares indicated as beneficially owned. Unless otherwise indicated, the address for each person set forth in the table is c/o Bill Barrett Corporation, 1099 18th Street, Suite 2300, Denver, Colorado 80202.

In calculating the number of shares beneficially owned by each person and the percentage owned by each person, we assumed that all shares issuable upon exercise of options on or prior to May 15, 2005 are exercised by that person. The total number of shares outstanding used in calculating the percentage owned assumes no exercise of options held by other persons.

Name of Beneficial Owner	Number of Common Shares Beneficially Owned	Percentage of Outstanding Common Shares Beneficially Owned (1)
5% Stockholders:		
Warburg Pincus Private Equity VIII, L.P. 466 Lexington Avenue New York, NY 10017	10,081,278(2)	23.0%
The Goldman Sachs Group, Inc. 85 Broad Street New York, NY 10004	6,415,356(3)	14.6
The J.P. Morgan Entities 1221 Avenue of the Americas Floor 39 New York, NY 10020	4,582,400(4)	10.4
Executive Officers and Directors:		
William J. Barrett	1,064,303(5)(14)	2.4
J. Frank Keller	392,378(6)(14)	*
Fredrick J. Barrett	232,397(7)(14)	*
Thomas B. Tyree, Jr.	329,091(8)(14)	*
Francis B. Barron	31,716(9)	*
Philippe S.E. Schreiber	42,453(10)	*
Richard Aube	4,582,400(4)(11)	10.4
Henry Cornell	6,415,356(3)	14.6
Jeffrey A. Harris	10,081,278(2)	23.0
James M. Fitzgibbons	23,585	*
Roger Jarvis	18,368(12)	*
Randy Stein	500	*
Michael E. Wiley	--	--
All executive officers and directors as a group (21 persons)	24,265,609(2)(3)(4)(5)(6)(7)(8)(9)(10)(11)(12)(13)(14)	55.3

* Less than 1%

(1) Based on an aggregate of 43,362,738 shares of common stock issued and outstanding as of March 1, 2005.

(2) Consists of shares directly owned by Warburg Pincus Private Equity VIII, L.P., including three related limited partnerships. Warburg Pincus & Co. serves as the sole general partner of Warburg Pincus Private Equity VIII, L.P. and that limited partnership is managed by Warburg Pincus LLC. Our director, Jeffrey A. Harris, is a general partner of Warburg Pincus & Co. and a member and managing director of Warburg Pincus LLC. All shares indicated owned by Mr. Harris are included because of his affiliation with the Warburg Pincus entities. Mr. Harris disclaims beneficial ownership of all the shares of common stock held by Warburg Pincus Private Equity VIII, L.P. and its affiliates. The 10,081,278 shares are included three times in the table under the beneficial ownership of each of Mr. Harris, Warburg Pincus Private Equity VIII, L.P. and all executive officers and directors as a group.

(3) The Goldman Sachs Group, Inc., which we refer to as GS Group, and certain affiliates, may be deemed to own beneficially and indirectly in the aggregate 6,415,356 shares of common stock which are owned directly or indirectly by investment partnerships, of which affiliates of Goldman Sachs and GS Group are the general partner or managing general partner. We refer to these investment partnerships as the GS Limited Partnerships. Goldman Sachs is the investment manager of certain of the GS Limited Partnerships. The GS Limited Partnerships and their respective beneficial ownership of shares of our common stock are: (a) GS Capital Partners 2000, L.P. 3,458,023 shares, (b) GS Capital Partners 2000 Offshore, L.P. 1,256,512 shares (owned indirectly through GSCP 2000 Offshore BBOG Holding, L.P.), (c) GS Capital Partners 2000 GmbH & Co. Beteiligungs KG 144,538 shares (owned indirectly through GSCP 2000 GmbH BBOG Holding, L.P.), (d) GS Capital Partners 2000 Employee Fund, L.P. 1,098,043 shares, (e) Goldman Sachs Direct Investment Fund 2000, L.P. 229,120 shares, and (f) Stone Street Fund 2000, L.P. 229,120 shares (owned both directly and indirectly through Stone Street BBOG Holding). Our director Henry Cornell is a managing director of Goldman Sachs. Mr. Cornell, Goldman Sachs and GS Group each disclaims beneficial ownership of the

shares owned directly or indirectly by the GS Limited Partnerships, except to the extent of their pecuniary interest therein, if any. The shares are included three times in the table under the beneficial ownership of each of Mr. Cornell, GS Group and all executive officers and directors as a group.

(4) Includes 3,382,856 shares of common stock owned by J.P. Morgan Partners (BHCA), L.P., 578,471 shares owned by J.P. Morgan Partners Global Investors, L.P., 251,691 shares owned by J.P. Morgan Partners Global Investors (Cayman), L.P., 32,660 shares owned by J.P. Morgan Partners Global Investors (Cayman) II, L.P., 81,424 shares owned by JPMP Global Fund/Bill Barrett A, L.P., 41,095 shares owned by JPMP Global Fund/Bill Barrett, L.P., 101,211 shares owned by J.P. Morgan Partners Global Investors (Selldown), L.P., and 112,992 shares owned by JPMP Global Fund/Bill Barrett/ Selldown, L.P. We refer to these partnerships as the J.P. Morgan Entities. The general partner of J.P. Morgan Partners (BHCA), L.P. is JPMP Master Fund Manager, L.P. and the general partner of J.P. Morgan Partners Global Investors, L.P., J.P. Morgan Global Investors (Cayman), L.P., J.P. Morgan Partners Global Investors (Cayman) II, L.P., JPMP Global Fund/Bill Barrett, L.P., JPMP Global Fund/Bill Barrett A, L.P., J.P. Morgan Partners Global Investors (Selldown), L.P., and JPMP Global Fund/Bill Barrett/Selldown, L.P., is JPMP Global Investors, L.P. The general partner of JPMP Master Fund Manager, L.P. and JPMP Global Investors, L.P. is JPMP Capital Corp., a wholly-owned subsidiary of J.P. Morgan Chase & Co., a publicly traded company. Each of JPMP Master Fund Manager, L.P., JPMP Capital Corp., JPMP Global Investors, L.P. and J.P. Morgan Chase & Co. may be deemed beneficial owners of the shares held by the J.P. Morgan Entities, however, the foregoing shall not be construed as an admission that such entities are the beneficial owners of the shares held by the J.P. Morgan Entities.

(5) Includes 104,372 common shares issuable upon exercise of vested options. Includes 384,676 shares owned by a limited liability limited partnership in which Mr. Barrett is the general partner.

(6) Includes 59,641 common shares issuable upon exercise of vested options.

(7) Includes 35,785 common shares issuable upon exercise of vested options.

(8) Includes 59,641 common shares issuable upon exercise of vested options.

(9) Includes 6,272 common shares issuable upon exercise of options that have vested or that will vest on or before May 15, 2005. Includes 878 shares held by Mr. Barron as custodian for his minor children.

(10) Includes 11,928 common shares issuable upon exercise of vested options. Includes 23,585 shares owned by Mr. Schreiber's spouse.

(11) Mr. Aube is a Partner of J.P. Morgan, LLC but does not have voting or dispositive power with respect to any of the shares beneficially owned by any of the J.P. Morgan Entities.

(12) Includes 14,075 common shares issuable upon exercise of vested options.

(13) Includes 505,747 common shares issuable upon exercise of vested options for all directors and executive officers as a group.

(14) 115,513 of the shares of common stock held by the executive officers are subject to the vesting requirements of a stockholders' agreement among all our current stockholders. For additional information, see "Item 13. Certain Relationships and Related Transactions—Investments in the Company". Also includes 2,446 shares issued as a restricted stock award to three of our officers. These shares are subject to the officer remaining an employee of the Company and vest 25% on each of March 9, 2006, 2007, 2008 and 2009.

Equity Compensation Plan Information

The following table provides aggregate information presented as of December 31, 2004 with respect to all compensation plans under which equity securities are authorized for issuance.

Plan Category	(a) Number of Securities to Be Issued Upon Exercise of Outstanding Options, Warrants and Rights	(b) Weighted Averaged Exercise Price of Outstanding Options, Warrants and Rights	(c) Number of Securities Remaining Available for Future Issuance (Excluding Securities Reflected in Column (a))
Equity compensation plans approved by shareholders	2,484,491	$21.96	3,915,776
Equity compensation plans not approved by shareholders	—	—	—
Total	2,484,491	$21.96	3,915,776

Item 13. Certain Relationships and Related Transactions

Following is a discussion of transactions between us and our officers, directors and stockholders owning more than 5% of the outstanding shares of preferred stock and common stock.

Mr. Cornell, a director of the Company, is a managing director of Goldman Sachs. Goldman Sachs Credit Partners L.P., an affiliate of Goldman Sachs, was the sole lead arranger, administrative agent, syndication agent and a lender under our Senior Subordinated Credit and Guaranty Agreement dated September 1, 2004, or the "bridge loan". A portion of the proceeds of our initial public offering were used to repay this bridge loan in December 2004. In management's opinion, the terms of this agreement were at least as favorable to the Company as could be obtained from non-related sources. Goldman Sachs is an affiliate of certain investors in our Series B preferred stock, which automatically converted into common stock upon the completion of our initial public offering in December 2004. Mr. Cornell initially was elected as a director pursuant to the stockholders' agreement and stock purchase agreement dated March 28, 2002, relating to the sale of the Series B preferred stock, pursuant to which certain affiliates of Goldman Sachs purchased a total of 14,000,000 shares of the Series B preferred stock for $5.00 per share for a total purchase price of $70,000,000, as further described below. J. Aron & Company, an affiliate of Goldman Sachs, is the counterparty to all of the Company's natural gas and oil swaps and collars. In management's opinion, the swap and collar terms were provided on terms at least as favorable to the Company as could be obtained from non-related sources.

Mr. Aube, a director of the Company, is a Partner of J.P. Morgan Partners LLC, a company affiliated with the lead arranger and agent for our revolving credit facility. In management's opinion, the terms obtained through the credit facility were provided on terms at least as favorable to the Company as could be obtained from non-related sources. Affiliates of J.P. Morgan Partners have provided commercial banking and related financial services to us in the past and are expected to provide similar services in the future. Mr. Aube was elected as the J.P. Morgan Entities (as defined below) nominee on our board of directors pursuant to the stockholders' agreement and Series B stock purchase agreement, relating to the sale of the Series B preferred stock, pursuant to which the J.P. Morgan Entities purchased 10,000,000 shares of the Series B preferred stock for $5.00 per share for a total purchase price of $50,000,000, as further described below.

Mr. Harris, a director of the Company, is a member and serves as a Managing Director at Warburg Pincus LLC. Mr. Harris initially was elected as a director pursuant to the stockholders' agreement and Series B stock purchase agreement, relating to the sale of the Series B preferred stock, pursuant to which an affiliate of Warburg Pincus purchased 22,000,000 shares of Series B preferred stock for $5.00 per share for a total purchase price of $110,000,000, as further described below.

In addition to the relationships described above, Goldman, Sachs & Co. and J.P. Morgan Securities Inc. served as underwriters in our initial public offering, which was completed in December 2004. Goldman, Sachs & Co. and J.P. Morgan Securities, Inc. received compensation of $10.4 million and $2.9 million, respectively, in the form of commission and underwriting discounts, net of expenses, for serving as underwriters.

Investments in the Company

In January 2002, the Company issued 1,800,548 shares of common stock to employees for $370,000 for the Company's initial funding. In connection with the Series B preferred stock purchase agreement entered into in March 2002, all our stockholders prior to our initial public offering were required to become parties to a stockholders' agreement originally entered into on March 28, 2002. The stockholders' agreement contains provisions concerning the appointment of directors, limitations on certain corporate activities, the issuance and transfer of securities, and the vesting of shares of common stock issued to employees in January 2002. These shares are subject to vesting requirements as to the length of service with the Company (20% vests each of January 31, 2002, 2003, 2004, 2005, and 2006, with all shares vesting upon an employee's reaching the age of 75), which is referred to as "Time Vesting", and also were subject to vesting requirements as to the amount of proceeds received by the Company from sales of Series B preferred stock to the investors in our Series B preferred stock, pursuant to the Series B stock purchase agreement entered into in March 2002, which is referred to as "Dollar Vesting". These management shares vest at the later to occur of Time Vesting and Dollar Vesting. Vesting stops upon the occurrence of a liquidation event with respect to the Company, as defined in the agreement, or the sale of the Company. Because the investors purchased all the Series B preferred stock that give rise to Dollar Vesting, the common stock acquired by employees is subject only to Time Vesting going forward. The stockholders' agreement terminates upon the closing of our initial public offering except for the provisions concerning the vesting of the common stock issued to management and requiring transfers of shares held by parties to the agreement to be made in accordance with applicable securities laws.

Since January 1, 2004, our officers, directors, key employees and 5% stockholders have invested cash in us in excess of $60,000 in exchange for shares of our common and Series B preferred stock in a series of offerings by us. The common stock was acquired in the directed share program in connection with our initial public offering at $25.00 per share and the Series B preferred was purchased during the period from January through May 2004 for $5.00 per share. The majority of the shares of Series B preferred stock were purchased by our institutional investors pursuant to the Series B stock purchase agreement dated March 28, 2002. These shares of Series B preferred stock were issued incrementally upon the occurrence of each capital call pursuant to the Series B stock purchase agreement, including 4 million shares issued for $20 million and 2.6 million shares issued for $13 million in January and May 2004, respectively. The investors have no further obligation or right to purchase Series B preferred stock pursuant to the stock purchase agreement. The preferred stock automatically converted to common stock upon the completion of our initial public offering in December 2004.

The following table summarizes the shares of our common stock acquired pursuant to the directed share program in our initial public offering, which is described below, and Series B preferred stock acquired from us in transactions in excess of $60,000, by our executive officers, directors and 5% stockholders and their immediate family members subsequent to January 1, 2004.

Officers, Directors and 5% Stockholders	**Common Stock**	**Series B Preferred Stock**	**Total Consideration**
William J. Barrett	32,000(1)(2)	—	$ 800,000
J. Frank Keller	20,000(1)(3)	—	500,000
Fredrick J. Barrett	27,300(1)(4)	—	682,500
Thomas B. Tyree, Jr	14,300	—	357,500
Robert W. Howard	—	—	—
Dominic J. Bazile II	2,600	—	65,000
Francis B. Barron	8,100	52,000 (5)	462,500
Huntington T. Walker	5,500	—	137,500
Terry R. Barrett	22,500(1)(6)	—	562,500
Lynn Boone Henry	10,200	—	255,000
Kurt M. Reinecke	—	—	—
Wilfred R. (Roy) Roux	—	—	—
Duane J. Zavadil	5,000	—	125,000
James M. Fitzgibbons	—	—	—
Roger L. Jarvis	—	—	—
Philippe S.E. Schreiber	—	—	—
Randy Stein	—	—	—
Michael E. Wiley	—	—	—
Warburg Pincus Private Equity VIII, L.P	—	2,847,060 (7)	14,235,300
The Goldman Sachs Group, Inc	—	1,811,762 (8)	9,058,810
The J.P. Morgan Entities	—	1,293,667 (9)	6,468,335

(1) William J. Barrett is the father of Fredrick J. Barrett and Terry Barrett and the brother-in-law of J. Frank Keller. As a result of the requirements to disclose transactions by immediate family members, shares for these officers are included more than once in this table.

(2) Includes 30,200 shares that are also included under J. Frank Keller, Fredrick J. Barrett, and Terry Barrett.

(3) Includes 20,000 shares that are also included under William J. Barrett.

(4) Includes 25,200 shares that are also included under William J. Barrett and Terry Barrett.

(5) Includes 2,000 shares held by Mr. Barron's minor children.

(6) Includes 21,800 shares that are also included under William J. Barrett and Fredrick J. Barrett.

(7) One of our directors, Mr. Harris, is affiliated with Warburg Pincus Private Equity Partners VIII, L.P. You can read more about Mr. Harris' affiliation with Warburg Pincus Private Equity VIII, L.P. under the heading "Principal Stockholders".

(8) The shares shown in the table are held directly or indirectly by investment partnerships affiliated with The Goldman Sachs Group, Inc., with which one of our directors, Mr. Cornell is affiliated. You can read more about Mr. Cornell's affiliation with these entities under the heading "Principal Stockholders".

(9) The shares shown in the table are held by J.P. Morgan Partners (BHCA), L.P., J.P. Morgan Partners Global Investors, L.P., J.P. Morgan Partners Global Investors (Cayman), L.P., J.P. Morgan Partners Global Investors (Cayman) II, L.P., JPMP Global Fund/Bill Barrett A, L.P., JPMP Global Fund/Bill Barrett, L.P., J.P. Morgan Partners Global Investors (Selldown), L.P., and JPMP Global Fund/Bill Barrett/Selldown, L.P., with which one of our directors, Mr. Aube, is affiliated. You can read more about Mr. Aube's affiliation with these entities under the heading "Principal Stockholders".

Directed Share Program

At our request, the underwriters reserved 600,000 shares of common stock in our initial public offering for sale under a directed share program at the initial public offering price of $25.00 per share to officers and other employees, directors, family members of officers and representatives of clients, vendors and suppliers and industry partners, all of whom were required to be natural persons and could not include venture capital firms or other entities. The number of shares of common stock purchased by our officers and directors, and their immediate family members, pursuant to the directed share program are included in the table above.

Registration Rights Agreements

Agreement with Series B Preferred Stock Investors

On March 28, 2002, we entered into a registration rights agreement with the holders of our Series B preferred stock who purchased 51,000,000 shares pursuant to the stock purchase agreement dated March 28, 2002. Pursuant to the registration rights agreement, we have agreed to register the transfer of the 23,370,233 shares of our common stock they received upon conversion of their Series B preferred stock immediately prior to the completion of our initial public offering, under certain circumstances. These holders include (directly or indirectly through subsidiaries or affiliates), among others, The Goldman Sachs Group, Inc., the J.P. Morgan Entities and Warburg Pincus Private Equity VIII, L.P.

Demand Registration Rights. At any time after our initial public, each stockholder who is the holder of (1) more than 10% of our then outstanding common stock, (2) common stock with an aggregate current market value of at least $50,000,000 or (3) stockholders holding at least 60% of the shares of common stock shall have the right to require us by written notice to register a specified number of shares in accordance with the Securities Act and the registration rights agreement. Until we are eligible to use Form S-3 for registration under the Securities Act, each qualified holder has the right to request up to two registrations. Once we are eligible to use Form S-3 for registration, each qualified holder has the right to request up to five registrations, minus any demand registration rights exercised prior to that date. Nevertheless, in no event shall more than one demand registration occur during any six-month period or within 120 days after the effective date of a registration statement, provided that no demand registration may be prohibited for that 120-day period more than once in any 12-month period.

Piggy-back Registration Rights. If at any time after our initial public we propose to file a registration statement under the Securities Act with respect to an offering of common stock (subject to certain exceptions), whether or not for our own account, then we must give at least 30 days' notice prior to the anticipated filing date to all holders of registrable securities to allow them to include a specified number of their shares in that registration statement. We will be required to maintain the effectiveness of that registration statement until the earlier of 120 days after the effective date and the consummation of the distribution by the participating holders.

Conditions and Limitations; Expenses. These registration rights are subject to certain conditions and limitations, including the right of the underwriters to limit the number of shares to be included in a registration and our right to delay or withdraw a registration statement under certain circumstances. We will generally pay all registration expenses in connection with a demand registration or a registration on Form S-3, regardless of whether a registration statement is filed or becomes effective.

Agreement With Bridge Lender

In September 2004, we entered into a registration rights agreement with Goldman Sachs Credit Partners, L.P. in connection with the bridge loan we received from that lender. We agreed to register the transfer of senior subordinated exchange notes that may be issued under the bridge loan agreement if the bridge loan is not paid by September 1, 2005. We used a portion of the net proceeds of our initial public offering to repay the entire bridge loan. As a result, the registration agreement has terminated.

Management Rights Agreement

We have entered into a management rights agreement with each of the Goldman entities, the J.P. Morgan Entities and Warburg Pincus Private Equity VIII, L.P., who purchased our Series B preferred stock pursuant to the stock purchase agreement. Under the terms of this agreement, each of these investors is entitled to (1) consult with and advise us on significant business issues, (2) examine our records, subject to customary confidentiality restrictions on the use of such information, and (3) be notified of and attend all meetings of the board in a non-voting advisory capacity and receive all materials distributed to board members. The parties to the management rights agreement do not receive compensation under the agreement. Each respective agreement will terminate upon the date on which the relevant investor owns less than five percent of our capital stock.

Regulatory Sideletter

On March 28, 2002, we entered into a regulatory sideletter with J.P. Morgan Partners (BHCA), L.P., an affiliate of J.P. Morgan Chase & Co. and a regulated entity and a holder of 106% of our common stock. J.P. Morgan Partners (BHCA), L.P.'s affiliate was a joint-lead manager in our initial public. Under the terms of this sideletter, we agreed to cooperate with J.P. Morgan Partners (BHCA), L.P. in all reasonable respects to assist its regulatory compliance in connection with legal restrictions, including banking regulations, on the type and terms of its investment in our securities, including conversion to nonvoting securities. This sideletter will terminate upon the date on which J.P. Morgan Partners (BCHA), L.P. owns less than five percent of our capital stock.

Item 14. Principal Accounting Fees and Services

Audit Fees

The aggregate fees billed for professional services rendered by Deloitte & Touche LLP for its audit of our annual financial statements and its review of our quarterly financial statements, including our financial statements included in our Registration Statement on Form S-1 in connection with our initial public offering of common stock in December 2004, for the fiscal years 2003 and 2004 were $98,000 and $690,000, respectively.

Audit Related Fees

The aggregate fees billed for professional services rendered by Deloitte & Touche LLP for assurance and related services that are reasonably related to the performance of audit or review of our financial statements for the fiscal years 2003 and 2004 were $22,000 and $48,000, respectively. These fees were accrued in connection with the audit of the Statements of Revenues and Direct Operating Expenses for the Wind River Acquisition Properties and Piceance Basin Acquisition Properties for our Registration Statement in connection with our initial public offering.

Tax Fees

The aggregate fees billed for professional services rendered by Deloitte & Touche LLP for professional services for tax compliance, tax advice or tax planning for the fiscal years 2003 and 2004 were $42,000 and $49,000, respectively.

All Other Fees

Fees paid to Deloitte & Touche LLP by the Company during the years ended December 31, 2003 and 2004 for all other non-audit services rendered to the Company totaled approximately $3,000 and $0, respectively.

Audit Committee Pre-Approval

Our Audit Committee Charter provides that either (i) the Audit Committee shall pre-approve all auditing and non-auditing services of the independent auditor, subject to de minimus exceptions for other than audit, review or attest services that are approved by the Audit Committee prior to completion of the audit; or (ii) that the engagement of the independent auditor be entered into pursuant to pre-approved policies and procedures established by the Audit Committee, provided that the policies and procedures are detailed as to the particular services and the Audit Committee is informed of each service. The Audit Committee pre-approved all of Deloitte & Touche LLP's fees for audit services in fiscal years 2003 and 2004. Except as indicated above, there were no fees other than audit fees for fiscal years 2003 and 2004, and the auditors engaged performed all the services described above with their full time permanent employees.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a)(1) and (a)(2) Financial Statements and Financial Statement Schedules

See "Item 8. Financial Statements and Supplementary Data" on page F-1(a)

(a)(3) Exhibits.

Exhibit Number	Description of Exhibits
3.1	Certificate of Incorporation of Bill Barrett Corporation, as amended to date. [Incorporated by reference to Exhibit 3.1 to the Company's Registration Statement on Form S-1 (File No. 333-115445).]
3.2	Restated Certificate of Incorporation of Bill Barrett Corporation effective immediately prior to the closing of the offering made pursuant to this registration statement. [Incorporated by reference to Exhibit 3.4 to the Company's Current Report on Form 8-K filed with the Commission on December 20, 2004.]
3.3	Bylaws of Bill Barrett Corporation. [Incorporated by reference to Exhibit 3.5 to the Company's Current Report on Form 8-K filed with the Commission on December 20, 2004.]
3.4	Certificate of Designations of Series A Preferred Stock. [Incorporated by reference to Exhibit 3.2 to Amendment No. 1 to the Company's Registration Statement on Form 8-A filed with the Commission on December 20, 2004.]
4.1	Specimen Certificate of Common Stock. [Incorporated by reference to Exhibit 3.2 to Amendment No. 1 to the Company's Registration Statement on Form 8-A filed with the Commission on December 20, 2004.]
4.2	Registration Rights Agreement, dated March 28, 2002, among Bill Barrett Corporation and the investors named therein. [Incorporated by reference to Exhibit 4.2 to the Company's Registration Statement on Form S-1 (File No. 333-115445).]
4.3	Stockholders' Agreement, dated March 28, 2002 and as amended to date, among Bill Barrett Corporation and the investors named therein. [Incorporated by reference to Exhibit 4.3 to the Company's Registration Statement on Form S-1 (File No. 333-115445).]
4.4	Rights Agreement dated as of December 15, 2004 by and between the Company and Mellon Investor Services LLC. [Incorporated by reference to Exhibit 4.4 to Amendment No. 1 to the Company's Registration Statement on Form 8-A filed with the Commission on December 20, 2004.]
10.1(a)	Amended and Restated Credit Agreement, dated February 4, 2004, among Bill Barrett Corporation and the banks named therein. [Incorporated by reference to Exhibit 10.1(a) to the Company's Registration Statement on Form S-1 (File No. 333-115445).]
10.1(b)	First Amendment to Amended and Restated Credit Agreement dated as of September 1, 2004 among Bill Barrett Corporation and the banks named therein. [Incorporated by reference to Exhibit 10.1(b) to the Company's Registration Statement on Form S-1 (File No. 333-115445).]
10.2	Stock Purchase Agreement, dated March 28, 2002, among Bill Barrett Corporation and the investors named therein. [Incorporated by reference to Exhibit 10.2 to the Company's Registration Statement on Form S-1 (File No. 333-115445).]
10.3	Purchase and Sale Agreement, dated March 27, 2002, between Williams Production RMT Company and Bill Barrett Corporation. [Incorporated by reference to Exhibit 10.3 to the Company's Registration Statement on Form S-1 (File No. 333-115445).]
10.4	Purchase and Sale Agreement, dated April 1, 2002, among Wasatch Oil & Gas, LLC, Wasatch Gas Gathering, LLC and Bill Barrett Corporation. [Incorporated by reference to Exhibit 10.4 to the Company's Registration Statement on Form S-1 (File No. 333-115445).]
10.5	Purchase and Sale Agreement, November 4, 2002, among, Intoil, Inc., Aratex Production Company and Bill Barrett Corporation. [Incorporated by reference to Exhibit 10.5 to the Company's Registration Statement on Form S-1 (File No. 333-115445).]
10.6	Purchase and Sale Agreement, dated January 1, 2003, among Independent Production Company, Inc., Sapphire

	Bay, LLC and Bill Barrett Corporation. [Incorporated by reference to Exhibit 10.6 to the Company's Registration Statement on Form S-1 (File No. 333-115445).]
10.7(a)*	Form of Indemnification Agreement dated April 15, 2004, between Bill Barrett Corporation and each of the directors and certain executive officers. [Incorporated by reference to Exhibit 10.10(a) to the Company's Registration Statement on Form S-1 (File No. 333-115445).]
10.7(b)*	Schedule of officers and directors party to Indemnification Agreements dated April 15, 2004 with Bill Barrett Corporation. [Incorporated by reference to Exhibit 10.10(b) to the Company's Registration Statement on Form S-1 (File No. 333-115445).]
10.8*	Employment Letter Agreement, dated January 10, 2003, between Thomas B. Tyree, Jr. and Bill Barrett Corporation. [Incorporated by reference to Exhibit 10.11 to the Company's Registration Statement on Form S-1 (File No. 333-115445).]
10.9*	Amended and Restated 2002 Stock Option Plan. [Incorporated by reference to Exhibit 10.12 to the Company's Registration Statement on Form S-1 (File No. 333-115445).]
10.10(a)*	Form of Tranche A Stock Option Agreement for 2002 Stock Option Plan. [Incorporated by reference to Exhibit 10.13(a) to the Company's Registration Statement on Form S-1 (File No. 333-115445).]
10.10(b)*	Form of Tranche B Stock Option Agreement for 2002 Stock Option Plan. [Incorporated by reference to Exhibit 10.13(b)to the Company's Registration Statement on Form S-1 (File No. 333-115445).]
10.11*	2003 Stock Option Plan. [Incorporated by reference to Exhibit 10.14 to the Company's Registration Statement on Form S-1 (File No. 333-115445).]
10.12*	Form of Stock Option Agreement for 2003 Stock Option Plan. [Incorporated by reference to Exhibit 10.15 to the Company's Registration Statement on Form S-1 (File No. 333-115445).]
10.13	Form of Management Rights Agreement between Bill Barrett Corporation and certain investors. [Incorporated by reference to Exhibit 10.16 to the Company's Registration Statement on Form S-1 (File No. 333-115445).]
10.14	Regulatory sideletter, dated March 28, 2002, between J.P. Morgan Partners (BHCA), L.P. and Bill Barrett Corporation. [Incorporated by reference to Exhibit 10.17 to the Company's Registration Statement on Form S-1 (File No. 333-115445).]
10.15	Purchase and Sale Agreement effective July 1, 2004 among Calpine Corporation and Calpine Natural Gas, L.P. and Bill Barrett Corporation. [Incorporated by reference to Exhibit 10.18 to the Company's Registration Statement on Form S-1 (File No. 333-115445).]
10.16	Senior Subordinated Credit and Guaranty Agreement dated as of September 1, 2004 among Bill Barrett Corporation, as Borrower, Bill Barrett Properties Inc. and Bill Barrett Production Company, as Guarantors, various lenders, Goldman Sachs Credit Partners L.P., as sole lead arranger and Goldman Sachs Credit Partners L.P., as administrative agent. [Incorporated by reference to Exhibit 10.19 to the Company's Registration Statement on Form S-1 (File No. 333-115445).]
10.17*	Form of Change in Control Severance Protection Agreement for named executive officers. [Incorporated by reference to Exhibit 10.20 to the Company's Registration Statement on Form S-1 (File No. 333-115445).]
10.18*	2004 Stock Incentive Plan. [Incorporated by reference to Exhibit 10.21 to the Company's Registration Statement on Form S-1 (File No. 333-115445).]
10.19*	Form of Stock Option Agreement for 2004 Stock Option Plan. [Incorporated by reference to Exhibit 10.22 to the Company's Registration Statement on Form S-1 (File No. 333-115445).]
10.20*	Severance Plan. [Incorporated by reference to Exhibit 10.23 to the Company's Registration Statement on Form S-1 (File No. 333-115445).]
14	Code of Ethics and Business Conduct
21.1	Subsidiaries of the Registrant. [Incorporated by reference to Exhibit 21.1 to the Company's Registration Statement on Form S-1 (File No. 333-115445).]
23.1	Consent of Deloitte & Touche LLP.
23.2	Consent of Ryder Scott Company, L.P., Independent Petroleum Engineers.
23.3	Consent of Netherland, Sewell & Associates, Inc., Independent Petroleum Engineers.
31.1	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer
31.2	Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer
32.1	Section 1350 Certification of Chief Executive Officer
32.2	Section 1350 Certification of Chief Financial Officer

* Indicates a management contract or compensatory plan or arrangement, as required by Item 15(a)(3).

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act Of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

BILL BARRETT CORPORATION

Date: March 15, 2005

By: /s/ William J. Barrett
William J. Barrett
Chairman and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act Of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ William J. Barrett William J. Barrett	Chairman of the Board of Directors and Chief Executive Officer (Principal Executive Officer)	March 15, 2005
/s/ Thomas B. Tyree, Jr. Thomas B. Tyree, Jr.	Chief Financial Officer (Principal Financial Officer)	March 15, 2005
/s/ Robert W. Howard Robert W. Howard	Executive Vice President-Finance and Investor Relations, and Treasurer (Principal Accounting Officer)	March 15, 2005
Richard Aube	Director	
/s/ Fredrick J. Barrett Fredrick J. Barrett	Director	March 15, 2005
/s/ Henry Cornell Henry Cornell	Director	March 15, 2005
/s/ Jeffrey A. Harris Jeffrey A. Harris	Director	March 15, 2005
/s/ Roger L. Jarvis Roger L. Jarvis	Director	March 15, 2005
/s/ James M. Fitzgibbons James M. Fitzgibbons	Director	March 15, 2005
/s/ J. Frank Keller J. Frank Keller	Director	March 15, 2005
/s/ Philippe S. E. Schreiber Philippe S. E. Schreiber	Director	March 15, 2005
/s/ Randy Stein Randy Stein	Director	March 15, 2005
/s/ Michael E. Wiley Michael E. Wiley	Director	March 15, 2005

[THIS PAGE LEFT BLANK INTENTIONALLY.]

FINANCIAL STATEMENTS

INDEX TO FINANCIAL STATEMENTS

Bill Barrett Corporation

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Bill Barrett Corporation
Denver, Colorado

We have audited the accompanying consolidated balance sheets of Bill Barrett Corporation and subsidiaries (the "Company") as of December 31, 2003 and 2004, and the related consolidated statements of operations, stockholders' equity and comprehensive loss, and cash flows for the period January 7, 2002 (inception) through December 31, 2002, and each of the years ended December 31, 2003 and 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Bill Barrett Corporation and subsidiaries as of December 31, 2003 and 2004, and the results of their operations and their cash flows for the period January 7, 2002 (inception) through December 31, 2002, and each of the years ended December 31, 2003 and 2004, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company changed its method of accounting for stock-based compensation in 2004 with the implementation of Statement of Financial Accounting Standards No. 123 (revised 2004) "Share-Based Payment".

DELOITTE & TOUCHE LLP

Denver, Colorado
March 9, 2005

BILL BARRETT CORPORATION

CONSOLIDATED BALANCE SHEETS

	As of December 31,	
	2003	2004
	(in thousands, except share and per share data)	
Assets:		
Current Assets:		
Cash and cash equivalents	$ 16,034	$ 99,926
Accounts receivable	15,347	31,149
Prepayments and other current assets	1,681	4,625
Deferred income taxes	2,585	2,190
Total current assets	35,647	137,890
Property and Equipment — At cost, successful efforts method for oil and gas properties:		
Proved oil and gas properties	291,602	517,210
Unevaluated oil and gas properties, excluded from amortization	56,345	137,605
Furniture, equipment and other	2,864	4,964
	350,811	659,779
Accumulated depreciation, depletion and amortization	(41,352)	(107,614)
Total property and equipment, net	309,459	552,165
Deferred Income Taxes	2,300	3,081
Deferred Financing Costs and Other Assets	363	3,022
Total	$347,769	$696,158
Liabilities and Stockholders' Equity:		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 29,577	$ 37,392
Amounts payable to oil and gas property owners	1,940	5,390
Production taxes payable	7,653	15,437
Derivative liability and other	6,986	3,887
Total current liabilities	46,156	62,106
Note Payable to Bank	57,000	—
Asset Retirement Obligations	4,297	11,806
Convertible Note Payable	1,900	—
Other Noncurrent Liabilities	90	2,514
Stockholders' Equity:		
Convertible preferred stock, $0.001 par value:		
Series A, 6,900,000 shares authorized; 6,258,994 shares issued and outstanding with a liquidation preference of $28,000 as of December 31, 2003; zero issued and outstanding as of December 31, 2004	6	—
Series B, 52,185,000 shares authorized; 45,145,700 shares issued and outstanding with a liquidation preference of $242,841 as of December 31, 2003; zero issued and outstanding as of December 31, 2004	45	—
Common stock, $0.001 par value; authorized 150,000,000 shares; 1,857,477 and 43,323,270 shares issued at December 31, 2003 and 2004, respectively, with 750,228 and 283,887 shares subject to restrictions, respectively	9	43
Additional paid-in capital	252,887	717,507
Accumulated deficit	(8,966)	(86,320)
Deferred compensation	(1,254)	(7,929)
Accumulated other comprehensive loss	(4,401)	(3,569)
Total stockholders' equity	238,326	619,732
Total	$347,769	$696,158

See notes to consolidated financial statements.

BILL BARRETT CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

	Period from January 7, 2002 (inception) through December 31,	Year Ended December 31,	
	2002	2003	2004
	(in thousands, except per share amounts)		
Revenues:			
Oil and gas production	$16,007	$75,252	$165,843
Other	74	184	4,137
Total revenues	16,081	75,436	169,980
Operating Expenses:			
Lease operating expense	2,231	8,462	14,592
Gathering and transportation expense	229	3,646	5,968
Production tax expense	2,021	9,815	20,087
Exploration expense	1,592	6,134	36,156
Impairment expense	—	1,795	516
Depreciation, depletion and amortization	9,162	30,724	68,202
General and administrative	5,476	14,213	18,061
Non-cash stock-based compensation	1,322	3,637	3,031
Total operating expenses	22,033	78,426	166,613
Operating (loss) income	(5,952)	(2,990)	3,367
Other Income and Expense:			
Interest income	303	123	437
Interest expense	(65)	(1,431)	(9,945)
Loss on sales of securities	(1,465)	—	—
Total other income and expense	(1,227)	(1,308)	(9,508)
Loss before Income Taxes	(7,179)	(4,298)	(6,141)
Benefit from Income Taxes	2,164	320	875
Loss from Continuing Operations	(5,015)	(3,978)	(5,266)
Income from Discontinued Operations — Net of taxes of $16	27	—	—
Net Loss	(4,988)	(3,978)	(5,266)
Less deemed dividends on preferred stock	—	—	(36,343)
Less cumulative dividends on preferred stock	(4,430)	(12,682)	(18,633)
Net loss attributable to common stock	$(9,418)	$(16,660)	$(60,242)
Net Loss Per Common Share:			
Basic			
Loss Per Common Share from Continuing Operations	$(18.07)	$(19.38)	$(15.40)
Discontinued Operations Per Common Share	0.05	—	—
Net Loss Per Common Share	$(18.02)	$(19.38)	$(15.40)
Diluted			
Loss Per Common Share from Continuing Operations	$(18.07)	$(19.38)	$(15.40)
Discontinued Operations Per Common Share	0.05	—	—
Net Loss Per Common Share	$(18.02)	$(19.38)	$(15.40)

See notes to consolidated financial statements.

BILL BARRETT CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE LOSS
Period from January 7, 2002 (inception) through December 31, 2002 and for the years ended December 31, 2003 and 2004

(in thousands)

	Convertible Preferred Stock	Common Stock	Additional Paid-In Capital	Accumulated Deficit	Deferred Compensation	Accumulated Other Comprehensive Loss	Total Stockholders' Equity	Comprehensive (Loss) Income
Balance — January 7, 2002 (inception)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Issuance of Series A convertible preferred stock for cash and marketable securities	6	—	25,594	—	—	—	25,600	—
Tax effect of issuance of Series A convertible preferred stock in exchange for marketable securities	—	—	(996)	—	—	—	(996)	—
Issuance of Series B convertible preferred stock for cash	21	—	105,479	—	—	—	105,500	—
Issuance of restricted common stock for cash	—	8	362	—	—	—	370	—
Offering costs paid on issuance of Series A and Series B convertible preferred stock	—	—	(3,985)	—	—	—	(3,985)	—
Tax effect of certain offering costs	—	—	827	—	—	—	827	—
Issuance of Series A convertible preferred stock for acquisition of mineral leasehold interests	—	—	500	—	—	—	500	—
Deferred compensation	—	—	1,508	—	(1,508)	—	—	—
Amortization of deferred compensation	—	—	—	—	1,322	—	1,322	—
Comprehensive loss:								
Net loss	—	—	—	(4,988)	—	—	(4,988)	(4,988)
Effect of derivative financial instruments, net of tax	—	—	—	—	—	(348)	(348)	(348)
Total comprehensive loss								$ (5,336)
Balance — December 31, 2002	$ 27	$ 8	$ 129,289	$ (4,988)	$ (186)	$ (348)	$ 123,802	$ —
Issuance of Series B convertible preferred stock for cash	24	—	118,952	—	—	—	118,976	—
Offering costs paid on issuance of Series B convertible preferred stock	—	—	(1,335)	—	—	—	(1,335)	—
Issuance of Series B convertible preferred stock for acquisition of mineral leasehold interests	—	—	1,253	—	—	—	1,253	—
Exercise of options	—	1	23	—	—	—	24	—
Stock-based compensation	—	—	434	—	—	—	434	—
Deferred compensation	—	—	4,271	—	(4,271)	—	—	—
Amortization of deferred compensation	—	—	—	—	3,203	—	3,203	—
Comprehensive loss:								
Net loss	—	—	—	(3,978)	—	—	(3,978)	(3,978)
Effect of derivative financial instruments, net of tax	—	—	—	—	—	(4,053)	(4,053)	(4,053)
Total comprehensive loss								$ (8,031)
Balance — December 31, 2003	$ 51	$ 9	$ 252,887	$ (8,966)	$ (1,254)	$ (4,401)	$ 238,326	$ —
Issuance of Series B convertible preferred stock for cash	7	—	33,723	—	—	—	33,730	—
Exercise of options	—	—	52	—	—	—	52	—
Issuance of Series B convertible preferred stock for acquisition of mineral leasehold interests	—	—	322	—	—	—	322	—
Cancellation of Series A convertible preferred stock	—	—	(500)	—	—	—	(500)	—
Reverse stock split: 1-for-4.658	—	(7)	7	—	—	—	—	—
Proceeds from initial public offering (net of underwriters' discount of $26,445)	—	15	347,290	—	—	—	347,305	—
Conversion of convertible note payable into common stock	—	—	1,900	—	—	—	1,900	—
Conversion of issued and outstanding Series A convertible preferred stock into common stock upon initial public offering	(6)	2	4	—	—	—	—	—
Conversion of issued and outstanding Series B convertible preferred stock into common stock upon initial public offering	(52)	24	28	—	—	—	—	—
Recognition of 7% cumulative dividend on Series B convertible stock in common stock	—	—	35,745	(35,745)	—	—	—	—
Recognition of deemed dividends related to the conversion of Series B convertible stock into common stock upon initial public offering	—	—	36,343	(36,343)	—	—	—	—
Stock-based compensation	—	—	286	—	—	—	286	—
Deferred compensation	—	—	9,420	—	(9,420)	—	—	—
Amortization of deferred compensation	—	—	—	—	2,745	—	2,745	—
Comprehensive (loss) income:								
Net loss	—	—	—	(5,266)	—	—	(5,266)	(5,266)
Effect of derivative financial instruments, net of tax	—	—	—	—	—	832	832	832
Total comprehensive loss								$ (4,434)
Balance — December 31, 2004	$ —	$43	$717,507	$ (86,320)	$(7,929)	$(3,569)	$619,732	

See notes to consolidated financial statements.

BILL BARRETT CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Period from January 7, 2002 (inception) through December 31, 2002	Year Ended December 31, 2003	Year Ended December 31, 2004
		(in thousands)	
Operating Activities:			
Net Loss	$(4,988)	$(3,978)	$ (5,266)
Adjustments to reconcile to net cash provided by operations:			
Depreciation, depletion and amortization	9,162	30,724	68,202
Impairment expense	—	1,795	516
Deferred income taxes	(2,164)	(320)	(875)
Exploratory dry hole costs and abandonments	—	2,479	23,495
Loss on sale of securities	1,465	—	—
Stock compensation and other non-cash charges	1,365	3,684	3,071
Amortization of deferred financing costs	6	148	4,409
Gain on sale of properties	—	—	(3,729)
Change in current assets and liabilities:			
Accounts receivable	(4,042)	(9,272)	(15,802)
Prepayments and other current assets	(551)	(803)	(2,037)
Accounts payable, accrued and other liabilities	2,110	3,490	3,664
Amounts payable to oil and gas property owners	287	1,314	3,450
Production taxes payable	1,229	4,612	7,784
Net cash provided by operating activities	3,879	33,873	86,882
Investing Activities:			
Additions to oil and gas properties, including acquisitions	(159,659)	(173,246)	(327,430)
Additions of furniture, equipment and other	(998)	(1,823)	(2,141)
Proceeds from sale of properties	—	11,878	8,811
Proceeds from sale of short-term investments	1,467	—	—
Net cash used in investing activities	(159,190)	(163,191)	(320,760)
Financing Activities:			
Proceeds from debt	35,419	110,000	288,000
Principal payments on debt	(419)	(88,000)	(345,000)
Proceeds from issuance of convertible note payable	1,900	—	—
Proceeds from sale of common and preferred stock	128,538	119,000	33,782
Proceeds from initial public offering	—	—	373,750
Offering costs	(3,985)	(1,335)	(26,384)
Deferred financing costs and other	(429)	(26)	(6,378)
Net cash provided by financing activities	161,024	139,639	317,770
Increase in Cash and Cash Equivalents	5,713	10,321	83,892
Beginning Cash and Cash Equivalents	—	5,713	16,034
Ending Cash and Cash Equivalents	$5,713	$16,034	$99,926

See notes to consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Period from January 7, 2002 (inception) through December 31, 2002 and for the years ended December 31, 2003 and 2004

1. Organization

Bill Barrett Corporation, a Delaware corporation, is an independent oil and gas company engaged in the acquisition, exploration, development and production of natural gas and crude oil. Since its inception on January 7, 2002, Bill Barrett Corporation has conducted its activities principally in the Rocky Mountain region of the United States.

2. Summary of Significant Accounting Policies

Basis of Presentation. The accompanying consolidated financial statements include the accounts of Bill Barrett Corporation and its wholly-owned subsidiaries (collectively, the "Company", "we", "us" or "our"). These statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). All significant intercompany accounts and transactions have been eliminated.

Use of Estimates. Preparation of the Company's financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses for the reporting period. Actual results could differ from those estimates.

Cash Equivalents. The Company considers all highly liquid investments with a remaining maturity of three months or less when purchased to be cash equivalents.

Oil and Gas Properties. The Company's oil and gas exploration and production activities are accounted for using the successful efforts method. Under this method, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether the well has found proved reserves. Generally, if an exploratory well does not find proved reserves within one year following completion of drilling, the costs of drilling the well are charged to expense and included within cash flows from investing activities in the Consolidated Statements of Cash Flows pursuant to Statement of Financial Accounting Standards ("SFAS") No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies.* The costs of development wells are capitalized whether productive or nonproductive. Oil and gas lease acquisition costs are also capitalized. Interest cost is capitalized as a component of property cost for exploration and development projects that require greater than six months to be readied for their intended use. To date, the Company has not capitalized any interest expense.

Other exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for oil and gas leases, are charged to expense as incurred. The sale of a partial interest in a proved property is accounted for as a cost recovery and no gain or loss is recognized as long as this treatment does not significantly affect the unit-of-production amortization rate. A gain or loss is recognized for all other sales of proved properties. Maintenance and repairs are charged to expense, and renewals and betterments are capitalized to the appropriate property and equipment accounts. During 2004, the Company recorded impairment expense of $516,000 related to evaluated properties.

Unevaluated properties with significant acquisition costs are assessed periodically on a property-by-property basis and any impairment in value is charged to expense. If the unevaluated properties are subsequently determined to be productive, the related costs are transferred to proved oil and gas properties. Proceeds from sales of partial interests in unproved leases are accounted for as a recovery of cost without recognizing any gain or loss. During 2003, the Company recorded impairment expense of $1,795,000 related to unevaluated properties.

Net capitalized costs relating to the Company's oil and gas producing activities are summarized as follows (in thousands):

	As of December 31,		
	2002	2003	2004
Proved properties	$ 123,893	$ 163,685	$258,387
Wells and related equipment and facilities	7,726	119,134	216,335
Support equipment and facilities	1,762	8,694	38,890
Materials and supplies	—	89	3,598
Total proved oil and gas properties	133,381	291,602	517,210
Accumulated depreciation, depletion and amortization	(8,896)	(40,027)	(105,633)
Total proved oil and gas properties, net	$ 124,485	$ 251,575	$411,577
Unevaluated properties	$ 15,430	$ 40,877	$97,099
Wells and equipment in progress	4,390	15,468	40,506
Total unevaluated oil and gas properties, excluded from amortization	$ 19,820	$ 56,345	$137,605

The following table reflects the net changes in capitalized exploratory well costs for the period January 7, 2002 (inception) through December 31, 2002 and for the years ended December 31, 2003 and 2004.

	For the Period from Inception (January 7, 2002) to December 31, 2002	Year Ended December 31, 2003	Year Ended December 31, 2004
		(in thousands)	
Beginning of period	$ —	$ 2,825	$ 310
Additions to capitalized exploratory well costs pending the determination of proved reserves	4,058	37,801	85,445
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(1,233)	(38,103)	(42,788)
Exploratory well costs charged to expense	—	(2,213)	(23,027)
End of period	$ 2,825	$ 310	$ 19,940

The Company reviews its proved oil and gas properties for impairment whenever events and circumstances indicate a decline in the recoverability of their carrying value may have occurred. The Company estimates the expected undiscounted future cash flows of its oil and gas properties and compares such undiscounted future cash flows to the carrying amount of the oil and gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will adjust the carrying amount of the oil and gas properties to fair value. The factors used to determine fair value include, but are not limited to, estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures, and a discount rate commensurate with the risk associated with realizing the expected cash flows projected.

The provision for depreciation, depletion and amortization ("DD&A") of oil and gas properties is calculated on a field-by-field basis using the unit-of-production method. Oil is converted to natural gas equivalents, Mcfe, at the rate of one barrel to six Mcf. Taken into consideration in the calculation of DD&A are estimated future dismantlement, restoration and abandonment costs, net of estimated salvage values.

Furniture, Equipment and Other. Land and other office and field equipment are recorded at cost. Costs of renewals and improvements that substantially extend the useful lives of the assets are capitalized. Leasehold improvements are amortized over the life of the lease. Maintenance and repairs are expensed when incurred. Depreciation of other property and equipment is computed using the straight-line method over their estimated useful lives, all of which are currently estimated to be three years. Upon retirement or disposition of assets, the costs and related accumulated depreciation are removed from the accounts with the resulting gains or losses, if any, reflected in results of operations.

Environmental Liabilities. Environmental expenditures that relate to an existing condition caused by past operations and that do not contribute to current or future revenue generation are expensed. Liabilities are accrued when environmental assessments and/or clean-ups are probable, and the costs can be reasonably estimated. As of December 31, 2003 and 2004, the Company has not accrued for nor been fined or cited for any environmental violations, which would have a material adverse effect upon capital expenditures, operating results or the competitive position of the Company.

Revenue Recognition. The Company records revenues from the sales of natural gas and crude oil when delivery to the customer has occurred and title has transferred. This occurs when oil or gas has been delivered to a pipeline or a tank lifting has occurred.

The Company may have an interest with other producers in certain properties, in which case the Company uses the sales method to account for gas imbalances. Under this method, revenue is recorded on the basis of gas actually sold by the Company. In addition, the Company records revenue for its share of gas sold by other owners that cannot be volumetrically balanced in the future due to insufficient remaining reserves. The Company also reduces revenue for other owners' gas sold by the Company that cannot be volumetrically balanced in the future due to insufficient remaining reserves. The Company's remaining over- and under-produced gas balancing positions are considered in the Company's proved oil and gas reserves. Gas imbalances at December 31, 2003 and 2004 were not significant.

Comprehensive (Loss) Income. Comprehensive (loss) income consists of net (loss) income and the effective component of derivative instruments classified as cash flow hedges. Comprehensive (loss) income is presented net of income taxes in the Consolidated Statements of Stockholders' Equity.

Derivative Instruments and Hedging Activities. The Company periodically uses derivative financial instruments to achieve a more predictable cash flow from its gas and oil production by reducing its exposure to price fluctuations.

The Company accounts for such activities pursuant to SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended. This statement establishes accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded at fair market value and included in the Consolidated Balance Sheets as assets or liabilities.

The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. SFAS No. 133 requires that a company formally document, at the inception of a hedge, the hedging relationship and the entity's risk management objective and strategy for undertaking the hedge, including identification of the hedging instrument, the hedged item or transaction, the nature of the risk being hedged, the method that will be used to assess effectiveness and the method that will be used to measure hedge ineffectiveness of derivative instruments that receive hedge accounting treatment.

For derivative instruments designated as cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. Hedge effectiveness is assessed quarterly based on total changes in the derivative's fair value. Any ineffective portion of the derivative instrument's change in fair value is recognized immediately in earnings.

The Company may utilize derivative financial instruments which have not been designated as hedges under SFAS No. 133 even though they protect the Company from changes in commodity prices. These instruments are marked to market with the resulting changes in fair value recorded in earnings.

Deferred Financing Costs. Costs incurred in connection with the execution of the Company's credit facility and bridge loan have been capitalized and are amortized over the life of the facilities.

Income Taxes. Income taxes are provided for the tax effects of transactions reported in the financial statements and consist of taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income tax assets and liabilities represent the future tax return consequences of those differences, which will either be taxable or deductible when assets are recovered or settled. Deferred income taxes are also recognized for tax credits that are available to offset future income taxes. Deferred income taxes are measured by applying currently enacted tax rates.

Stock-Based Compensation. In December 2004, the Financial Accounting Standards Board ("FASB") issued SFAS No. 123 (revised 2004) ("SFAS No. 123R"), *Share-Based Payment,* which revises SFAS No. 123, *Accounting for Stock-Based Compensation,* and supersedes Accounting Principles Board ("APB") Opinion No. 25, *Accounting for Stock Issued to Employees.* SFAS No. 123R establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods and services, focusing primarily on accounting for transactions in which an entity obtains employee services in share-based payment transactions. It also addresses transactions in which an entity incurs liabilities in exchange for goods and services that are based on the fair value of the entity's equity instruments or that may be settled by the issuance of those equity instruments. We early adopted the provisions of the new standard effective October 1, 2004. Prior to the adoption of SFAS No. 123R, we used the intrinsic value method in accordance with APB Opinion No. 25 and the disclosure provisions of SFAS No. 123.

For awards granted while we were a nonpublic company (those granted prior to April 16, 2004, which date is defined by SFAS No. 123R as the date that the Company made a filing with a regulatory agency in preparation for the sale of equity securities in a public market), we adopted SFAS No. 123R using the prospective transition method. Under the prospective transition method, we continue to account for the portion of the awards outstanding using the minimum value method described under SFAS No. 123. Accordingly, zero compensation expense was recorded upon adoption of SFAS No. 123R for those awards.

For awards granted after we were a public company (those granted subsequent to April 16, 2004 as defined in SFAS No. 123R), we adopted SFAS No. 123R using the modified prospective application effective October 1, 2004, whereby as of that date we began applying the provisions of SFAS No. 123R to new awards and to awards modified, repurchased, or cancelled after October 1, 2004. We recognized share-based employee compensation cost based on the historical grant-date fair value as computed under SFAS No. 123 on October 1, 2004 for the portion of awards previously issued and for which the requisite service had not yet been rendered.

The Company recognized an additional $6,000 in non-cash stock-based compensation expense for the year ended December 31, 2004 and an ending balance of $58,000 in deferred compensation at December 31, 2004 as a result of the transition of awards that were granted after we were considered a public company from APB No. 25 to SFAS No. 123R using the modified prospective method. New awards granted subsequent to the adoption of SFAS No. 123R resulted in $146,000 of non-cash stock-based compensation expense for the year ended December 31, 2004 and an ending balance of $6.9 million in deferred compensation as of December 31, 2004. The total effect of applying the provisions of SFAS No. 123R is indicated below:

	Year Ended December 31, 2004 Increase (Decrease) (in thousands, except per share data)	
Loss from Continuing Operations	$	(152)
Loss before Income Taxes		(152)
Net Loss	$	(152)
Cash Flow from Operations		--
Cash Flow from Financing Activities		--
Basic Loss per Common Share	$	(0.04)
Diluted Loss per Common Share	$	(0.04)

The following table illustrates the pro forma effect on net income and loss per share if compensation costs had been determined based upon the fair value at the grant dates in accordance with SFAS No. 123 for stock option grants issued after we were considered a public company on April 16, 2004, as defined by SFAS No. 123, but before adoption of SFAS No. 123R on October 1, 2004:

	Period from January 7, 2002 (inception) through December 31, 2002	Year Ended December 31, 2003	Year Ended December 31, 2004
	(in thousands, except per share amounts)		
Net loss, as reported	N/A	N/A	$ (5,266)
Add stock-based compensation included in reported net loss, net of related tax effects	N/A	N/A	3,003
Deduct stock-based compensation expense determined under fair value method, net of related tax effects	N/A	N/A	(3,016)
Pro forma net loss	N/A	N/A	(5,279)
Less cumulative and deemed dividends on preferred stock	N/A	N/A	(54,975)
Pro forma loss attributable to common stock	N/A	N/A	$ (60,254)
Basic loss per share:			
As reported	N/A	N/A	$ (15.40)
Pro forma	N/A	N/A	$ (15.40)
Diluted loss per share:			
As reported	N/A	N/A	$ (15.40)
Pro forma	N/A	N/A	$ (15.40)

The Company continues to account for certain stock options under the original provisions of APB No. 25 as those options were issued prior to April 16, 2004, when we were considered a nonpublic entity as defined by SFAS No. 123R. As those options were accounted for under the minimum-value method, the calculated fair value is not comparable to those options issued subsequent to April 16, 2004, in which a fair-value-based method was then used. Therefore, pro forma disclosures for stock options granted while we were a nonpublic company accounted for using the minimum-value method have not been included pursuant to SFAS No. 123R.

Earnings Per Share. Basic net loss per common share of stock is calculated by dividing net loss attributable to common stock by the weighted-average of vested common shares outstanding during each period. Diluted net loss attributable to common shareholders is calculated by dividing net loss attributable to common shareholders by the weighted-average of common shares outstanding and other dilutive securities.

Net loss attributable to common stock is calculated by reducing net (loss) income by dividends earned on preferred securities. Series B preferred dividends, whether or not declared or paid, are considered earned for these calculations. The Series A and Series B preferred stock, the convertible note, the issued common shares subject to restrictions and outstanding options, have not been included in the computation of earnings per share for the period from January 7, 2002 (inception) through December 31, 2002, and the years ended December 31, 2003 and 2004, as their inclusion would have been anti-dilutive.

The Emerging Issues Task Force, ("EITF"), has issued EITF Issue No. 03-6, *Participating Securities and the Two-Class Method under FASB Statement No. 128 "Earnings Per Share"*, ("EITF 03-6"). We adopted EITF 03-6 as of January 1, 2004, and applied it retroactively, but the implementation had no effect in all prior periods. EITF 03-6 provides guidance for the computation of earnings per share using the two-class method for enterprises with participating securities or multiple classes of common stock as required by SFAS No. 128. The two-class method allocates undistributed earnings to each class of common stock and participating securities for the purpose of computing basic earnings per share. However, upon completion of our Initial Public Offering ("IPO") on December 15, 2004, all outstanding preferred securities were converted into common stock and, thus, we were not required to apply the two-class method for the year ended December 31, 2004. The weighted-average common shares outstanding reflect the reverse split that occurred in conjunction with our IPO. For the year ended December 31, 2004, we have included the deemed dividends previously measured related to issuance of preferred securities and their beneficial conversion in the calculation to determine net loss attributable to common stock because the contingency related to the conversion has been resolved due to the completion of the IPO.

The following table sets forth the calculation of basic and diluted earnings per share:

	For the Period from Inception (January 7, 2002) to December 31,	Year Ended December 31,	
	2002	2003	2004
	(in thousands except per share amounts)		
(Loss) from continuing operations	$ (5,015)	$ (3,978)	$ (5,266)
Less cumulative dividends on preferred stock	(4,430)	(12,682)	(18,633)
Less deemed dividends on preferred stock	—	—	(36,343)
Loss from continuing operations to be allocated	(9,445)	(16,660)	(60,242)
Income from discontinued operations	27	—	—
Less allocation of undistributed earnings to participating preferred stock	—	—	—
Net loss attributable to common stock	(9,418)	(16,660)	(60,242)
Adjustments to net income for dilution	n/a	n/a	n/a
Net loss adjusted for the effect of dilution	$ (9,418)	$ (16,660)	$ (60,242)
Basic weighted-average common shares outstanding in period	522.7	859.4	3,912.3
Add dilutive effects of stock options	—	—	—
Add dilutive effects of common stock subject to restrictions	—	—	—
Diluted weighted-average common shares outstanding in period	522.7	859.4	3,912.3
Basic loss per common share:			
Loss from continuing operations	$ (18.07)	$ (19.38)	$ (15.40)
Income from discontinued operations	0.05	n/a	n/a
Basic loss per common share	$ (18.02)	$ (19.38)	$ (15.40)
Diluted loss per common share:			
Loss from continuing operations	$ (18.07)	$ (19.38)	$ (15.40)
Income from discontinued operations	0.05	n/a	n/a
Diluted loss per common share	$ (18.02)	$ (19.38)	$ (15.40)

The weighted-average number of common shares outstanding used in the loss per share calculation is computed pursuant to SFAS No. 128. The weighted-average common shares outstanding does not include the 6,594,725 shares of Series A or the 51,951,418 shares of Series B preferred stock that were converted into to a total of 26,387,679 common shares until the completion of our IPO in December, 2004.

Industry Segment and Geographic Information. The Company operates in one industry segment, which is the exploration, development and production of natural gas and crude oil, and all of the Company's operations are conducted in the United States. Consequently, the Company currently reports a single industry segment.

Reclassifications. The Company reclassified $1.6 million and $3.7 million from cash used in investing activities to cash used in operating activities in the statements of cash flows for the period from January 7, 2002 (inception) through December 31, 2002 and for the year ended December 31, 2003, respectively, to conform to the current year presentation.

New Accounting Pronouncements. In September 2004, the FASB issued FASB Staff Position ("FSP") EITF Issue 03-1-1, *Effective Date of Paragraphs 10-20 of EITF Issue No. 03-1, "The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments"*, which delays the effective date for the recognition and measurement guidance in EITF Issue No. 03-1. In addition, the FASB has issued a proposed FSP to consider whether further application guidance is necessary for securities analyzed for impairment under EITF Issue No. 03-1. We continue to review the requirements of FSP EITF Issue 03-1-1 and do not expect that the adoption will have an impact on the Company's financial statements.

3. *Supplemental Disclosures of Cash Flow Information:*

Supplemental cash flow information is as follows:

	Period from January 7, 2002 (inception) through December 31, 2002	Year Ended December 31, 2003	Year Ended December 31, 2004
		(in thousands)	
Cash paid for interest	$ 16	$ 1,168	$ 5,362
Supplemental disclosures of noncash investing and financing activities:			
Preferred stock issued for payment of oil and gas properties	500	1,253	322
Preferred stock returned in settlement to terminate an exploration agreement	—	—	(500)
Preferred stock issued for marketable equity securities	2,932	—	—
Conversion of convertible note payable into Series A convertible preferred stock	—	—	1,900

4. *Acquisitions and Dispositions*

On March 28, 2002, the Company purchased oil and gas properties located in Wyoming from Williams Production RMT Inc. (the "Wind River Acquisition Properties"). The Company paid $74 million after normal price adjustments.

On April 30, 2002, the Company purchased oil and gas properties located in Utah from Wasatch Oil and Gas Inc. and affiliates. The Company paid $8.1 million in cash after normal price adjustments.

On July 1, 2002, the Company paid $2.5 million to the Crow Tribe in Montana (the "Crow Tribe") for an option to acquire leasehold interests pursuant to an exploration agreement dated June 11, 2002. Payment for the option consisted of $2.0 million in cash and 119,904 shares of the Company's Series A preferred stock. On August 1, 2002, the Company acquired from the Crow Tribe 11,540 leasehold acres for $2.6 million in cash. The Company and the Crow Tribe negotiated a settlement to terminate the exploration agreement, which was approved by the Bureau of Indian Affairs on February 20, 2004. The settlement agreement provides, among other things, for the Crow Tribe to return to the Company the 119,904 shares of Series A preferred stock, the payment of $2.4 million to the Company, and additional payments to the Company of $1.5 million over five and one half years with interest fixed at the prime rate in effect on February 20, 2004 plus 2%, or a total of 6%. An impairment charge of $856,000 was recorded as of December 31, 2003. The Company received the 119,904 shares of stock on March 8, 2004, and received the payment of $2.4 million on March 11, 2004. In addition, the first payment of $750,000 toward the $1.5 million, plus accrued interest, was received in February 2005.

On December 16, 2002, the Company purchased assets and assumed certain liabilities from Intoil, Inc. and an affiliate ("Intoil"). Included in the purchase were oil and gas properties located in Wyoming, Montana, North Dakota, Nebraska, Texas, Oklahoma, Utah, Nevada, New Mexico and Ohio. The Company paid $61.5 million in cash after normal price adjustments.

In conjunction with the acquisition from Intoil, liabilities were assumed as follows (in thousands):

Fair value of assets acquired	$ 63,800
Cash paid	(61,500)
Liabilities assumed	$ 2,300

In connection with the purchase of oil and gas properties from Intoil, management made a decision to sell certain of these properties which were either not located in the Rocky Mountain region, the Company's primary location of operations, or did not meet the profile of the Company's operations. The properties to be sold were classified as held for sale and were recorded at the fair value less costs to sell based largely on negotiated sales agreements with effective dates of January 1, 2003. In accordance with the provisions of SFAS No. 144, *Accounting for the Impairment and Disposal of Long Lived-Assets*, the results of operations relating to properties held for sale have been reported in discontinued operations in the Consolidated Statements of Operations, and with respect to these properties no depletion has been provided in the Consolidated Statements of Operations. Net operating receipts in 2003 plus sales proceeds of $10.8 million equaled the carrying value as of December 31, 2002.

The following unaudited pro forma information presents the financial information of the Company as if all the aforementioned acquisitions had occurred at January 7, 2002:

	Period from January 7, 2002 (inception) through December 31, 2002	
	As Reported	Pro Forma
	(in thousands)	
Revenues	$ 16,081	$ 37,553
Direct operating expenses	(4,481)	(11,075)
Revenues in excess of direct operating expenses	$ 11,600	$ 26,478

On March 21, 2003, the Company purchased predominantly non-producing and unevaluated oil and gas properties located in Wyoming from Independent Production Company, Inc. and Sapphire Bay, LLC, jointly as sellers. The Company paid $35.4 million in cash after normal price adjustments.

On September 1, 2004, the Company purchased certain oil and natural gas properties and related assets located in Colorado (the "Piceance Basin Acquisition Properties") from Calpine Corporation and Calpine Natural Gas L.P. The cash purchase price was $137.3 million after closing adjustments including revenue and operating expense between July 1, 2004 and September 1, 2004.

The following unaudited pro forma information presents the financial information of the Company as if the Piceance Basin Acquisition Properties were acquired on January 1, 2003:

	Year ended December 31,			
	2003		2004	
	As Reported	Pro Forma	As Reported	Pro Forma
	(in thousands)			
Revenue	$75,436	$90,302	$ 169,980	$ 182,271
Direct operating expenses	(21,923)	(24,379)	(40,647)	(42,489)
Revenues in excess of direct operating expenses	53,513	65,923	129,333	139,782
Net Loss	$(3,978)	$(4,070)	$ (5,266)	$ (4,049)
Basic and Diluted Net Loss Per Common Share	$(19.38)	$(19.49)	$ (15.40)	$ (15.09)

5. Note Payable to Bank

On December 16, 2002, the Company entered into a credit facility (the "Credit Facility") with commitments of $100 million and an initial borrowing base of $50 million, increased to $65 million in November 15, 2003, and a maturity date of December 16, 2005. The Credit Facility accrued interest based upon the borrowing base usage, at LIBOR or an alternate base rate (based upon the greater of the prime rate, a rate based upon the three month secondary CD rate, or on the federal funds effective rate) plus applicable margins ranging from 0% to 2.25%. The Credit Facility required commitment fees ranging from 0.375% to 0.50% of the unused borrowing base. Borrowings outstanding against the Credit Facility totaled $57 million at December 31, 2003. The weighted-average interest rate was 3.1% at December 31, 2003.

On February 4, 2004, the Company replaced its credit facility with a new credit facility which provides for a maturity date of February 4, 2007 and commitments of $200 million with an initial borrowing base of $150 million (the "New Credit

Facility"). The initial borrowing base under the New Credit Facility includes a $50 million portion, referred to as the "Tranche B" portion that allows the borrowing base to be greater than the typical borrowing base that would have been computed based on proved natural gas and oil reserves. The New Credit Facility bears interest, based on the borrowing base usage, at LIBOR or an alternate base rate (based upon the greater of the prime rate, or on the federal funds effective rate) plus applicable margins ranging from 0% to 3.75%. The Company pays commitment fees ranging from 0.375% to 0.50% of the unused borrowing base.

The New Credit Facility contains financial covenants, including but not limited to a maximum total debt to EBITDAX ratio (as defined), a minimum current ratio, an interest coverage ratio, and a minimum present value to total debt ratio. This facility is secured by the Company's oil and gas properties representing at least 85% of the total value of the Company's proved reserves and the pledge of all of the stock of the Company's subsidiaries.

On September 1, 2004, the Company amended its New Credit Facility to increase the borrowing base to $200 million from $150 million and to allow for incurrence of unsecured debt. The Tranche B portion was amended to be the lesser of $45 million and the difference between $200 million and the borrowing base computed by the bank group based on proved reserves. The Tranche B portion of the amended New Credit Facility terminates on November 30, 2005. At December 31, 2004, we had no borrowings outstanding under the New Credit Facility.

In order to fund the acquisition of the Piceance Basin Acquisition Properties and related costs (see Note 4), the Company entered into a senior subordinated credit and guaranty agreement, or bridge loan, which had a total principal amount of $150 million. In December 2004, the bridge loan was repaid in full with proceeds from our IPO. The interest rate under the bridge loan was equal to LIBOR, for one or three month periods as selected by the Company and which are known as interest periods, plus a margin. From September 1, 2004 to December 2004, the margin was 4.0%.

6. *Asset Retirement Obligations*

The Company adopted SFAS No. 143, *Accounting for Asset Retirement Obligations,* at inception on January 7, 2002. The estimated fair value of the future costs associated with dismantlement, abandonment and restoration of oil and gas properties is recorded generally upon acquisition or completion of a well. The net estimated costs are discounted to present values using a risk adjusted rate over the estimated economic life of the oil and gas properties. Such costs are capitalized as part of the related asset. The asset is depleted on the units-of-production method on a field-by-field basis. The associated liability is classified in other long-term liabilities in the accompanying Consolidated Balance Sheets. The liability is periodically adjusted to reflect (1) new liabilities incurred, (2) liabilities settled during the period, (3) accretion expense, and (4) revisions to estimated future cash flow requirements. The accretion expense is recorded as a component of depreciation, depletion and amortization expense in the accompanying Consolidated Statements of Operations.

A reconciliation of the Company's asset retirement obligations is as follows:

	Period from January 7, 2002 (inception) through December 31, 2002	Year Ended December 31, 2003	Year Ended December 31, 2004
		(in thousands)	
Beginning of period	$ —	$ 1,117	$ 4,297
Liabilities incurred	1,039	1,932	6,996
Liabilities settled	—	—	(848)
Accretion expense	78	244	397
Revisions to estimate	—	1,004	964
End of period	$ 1,117	$ 4,297	$ 11,806

7. *Fair Value of Derivatives and Other Financial Instruments*

The Company's financial instruments including cash and cash equivalents, accounts and notes receivable and accounts payable are carried at cost, which approximates fair value due to the short-term maturity of these instruments. The recorded value of the New Credit Facility, as discussed in Note 5, approximates the fair value due to its floating rate structure. The Company's commodity derivatives are marked to market with changes in fair value being recorded in other comprehensive income.

The estimated fair value of derivatives and other financial instruments has been determined by the Company using available market information and valuation methodologies described below. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

At December 31, 2004, the Company had in place swap contracts covering portions of its 2005 oil and gas production. The gas swaps, which are for the period January through December 2005, cover contracted volumes of 20,000 MMBtu per day of natural gas with a weighted-average fixed price of $5.16 per MMBtu. The index prices are based on Rocky Mountain delivery points. The oil swaps, which are for the period January through December 2005, cover contracted volumes of 400 barrels per day with a weighted-average fixed price of $34.78 per barrel and with index prices based on West Texas Intermediate Crude Oil as quoted on the New York Mercantile Exchange.

At December 31, 2004, the Company had the following commodity swap contracts in place to hedge cash flow and reduce the impact of oil and natural gas price fluctuations:

Product	Average Volume Per Day	Quantity Type	Fixed Price	Index Price(1)	Contract Period
Natural gas	10,000	MMBtu	$ 5.05	NORRM	1/1/2005 — 12/31/2005
Natural gas	10,000	MMBtu	5.27	NORRM	1/1/2005 — 12/31/2005
Oil	100	Bbls	32.96	WTI	1/1/2005 — 12/31/2005
Oil	100	Bbls	34.05	WTI	1/1/2005 — 12/31/2005
Oil	100	Bbls	36.12	WTI	1/1/2005 — 12/31/2005
Oil	100	Bbls	36.00	WTI	1/1/2005 — 12/31/2005

(1) NORRM refers to Northwest Pipeline Rocky Mountains price as quoted in Platt's Inside FERC on the first business day of each month. WTI refers to West Texas Intermediate price as quoted on the New York Mercantile Exchange.

At December 31, 2004, we had the following cashless collars (purchased put options and written call options) in order to hedge a portion of our 2005 and 2006 natural gas production. The cashless collars are used to establish floor and ceiling prices on anticipated future natural gas production and are also designated as cash flow hedges in accordance with SFAS No. 133.

Product	Average Volume Per Day	Quantity Type	Floor-Ceiling Pricing	Index Price(1)	Contract Period
Natural gas	10,000	MMBtu	$4.75-$7.00	NORRM	1/1/2005-12/31/2005
Natural gas	5,000	MMBtu	$4.75-$6.75	NORRM	1/1/2005-12/31/2005
Natural gas	10,000	MMBtu	$4.75-$7.10	NORRM	1/1/2005-12/31/2005
Natural gas	5,000	MMBtu	$4.75-$6.05	NORRM	1/1/2006-12/31/2006
Natural gas	5,000	MMBtu	$4.75-$6.18	NORRM	1/1/2006-12/31/2006
Natural gas	15,000	MMBtu	$4.75-$6.21	NORRM	1/1/2006-12/31/2006

The Company's natural gas and oil derivative financial instruments have been designated as cash flow hedges in accordance with SFAS No. 133 and are included in current and other long-term liabilities in the Company's Consolidated Balance Sheets.

At December 31, 2004, the estimated fair value of contracts designated and qualifying as cash flow hedges under SFAS No. 133 was a liability of $5.7 million. The Company will reclassify this amount to gains or losses included in oil and gas production operating revenues as the hedged production quantity is produced. Based on current prices, the net amount of existing unrealized after-tax loss as of December 31, 2004 to be reclassified from accumulated other comprehensive income to oil and gas production operating revenues in the next twelve months would be $2.5 million. The

Company anticipates that all original forecasted transactions will occur by the end of the originally specified time periods.

Derivative contract settlements included in oil and gas production operating revenues totaled net losses of $7.7 million and $12.4 million for the years ended December 31, 2003 and 2004, respectively. There were no derivative contract settlements for the period from January 7, 2002 (inception) through December 31, 2002. As the underlying prices in the Company's hedge contracts were consistent with the indices used to sell its oil and gas, no ineffectiveness was recognized related to its hedge contracts for the years ended December 31, 2003 and 2004.

8. Income Taxes

The benefit for income taxes consists of the following:

	Period from January 7, 2002 (inception) through December 31, 2002	Year Ended December 31, 2003	Year Ended December 31, 2004
		(in thousands)	
Deferred:			
Federal	$ 2,048	$ 296	$ 688
State	116	24	187
Total	$ 2,164	$ 320	$ 875

Income tax benefit differed from the amounts computed by applying the U.S. federal income tax rate of 34% to pretax loss from continuing operations as a result of the following:

	Period from January 7, 2002 (inception) through December 31, 2002	Year Ended December 31, 2003	Year Ended December 31, 2004
		(in thousands)	
Income tax benefit at the federal statutory rate	$ 2,441	$ 1,461	$ 2,088
State income taxes, net of federal tax effect	116	24	187
Non-deductible stock-based compensation	(409)	(1,185)	(1,392)
Other, net	16	20	(8)
Income tax benefit	$ 2,164	$ 320	$ 875

The tax effects of temporary differences that give rise to significant components of the deferred tax assets and deferred tax liabilities at December 31, 2003 and 2004 are presented below:

	December 31, 2003	December 31, 2004
	(in thousands)	
Current:		
Deferred tax assets:		
Derivative instruments	$ 2,585	$ 1,438
Accrued employee bonus	—	909
Other	—	(157)
Total current deferred tax assets	$ 2,585	$ 2,190
Long-term:		
Deferred tax assets:		
Net operating loss carryforward	$ 4,536	$ 15,155
Start-up/organization costs, net	628	431
Long-term derivative instruments	—	658
Stock-based compensation	—	354
Deferred rent	—	273

Other	—	32
Total long-term deferred tax assets	$ 5,164	$16,903
Deferred tax liabilities:		
Oil and gas properties	$ (2,822)	$(13,391)
Other	(42)	(431)
Total long-term deferred tax liabilities	(2,864)	(13,822)
Net long-term deferred tax assets	$ 2,300	$ 3,081

At December 31, 2004, the Company had approximately $40.8 million of federal and state tax net operating loss carryforwards which expire through 2024.

The Company has not recognized a valuation allowance against its net deferred tax assets because it believes that it is more likely than not that the net deferred tax assets will be realized on future income tax returns from the generation of future taxable income.

9. *Stockholders' Equity*

On December 9, 2004, the Company priced its shares to be issued in its IPO and began trading on the New York Stock Exchange the following day under the ticker symbol "BBG". Immediately prior to the IPO, a $1.9 million mandatorily convertible note was converted into 455,635 shares of Series A convertible preferred stock ("Series A preferred"), all of the then outstanding shares of Series A preferred and Series B convertible preferred stock ("Series B preferred") were converted into 2,592,317 and 23,795,362 shares, respectively, of common stock, and the 9,242,648 shares of issued common stock were reverse split into 1,984,303 shares of common stock. Through the IPO, the Company sold an additional 14,950,000 shares of common stock to the public at the offering price of $25.00 per share, resulting in total outstanding shares of 43,321,982 immediately following the IPO. The Company received $347.3 million in net proceeds after deducting underwriters' fees and related offering expenses. The proceeds received from the IPO were used principally to pay down debt outstanding under our credit facility and the bridge loan.

The Company's authorized capital structure consists of 75,000,000 shares of $0.001 par value preferred stock and 150,000,000 shares of $0.001 par value common stock. In October 2004, 150,000 shares of $0.001 par value preferred stock were designated as Series A Junior Participating Preferred Stock. At December 31, 2004, the Series A Junior Participating Preferred Stock was the Company's only designated preferred stock, the remainder of authorized preferred stock being undesignated. Until the date of the Company's IPO, 6,900,000 shares were designated as Series A preferred stock and 52,185,000 shares were designated as Series B preferred stock, both of which were eliminated in December 2004 following the Company's IPO.

Holders of all classes of stock are entitled to vote on matters submitted to stockholders, except that each share of Series A Junior Participating Stock shall entitle the holder thereof to 1,000 votes on all matters submitted to a vote of the Company's stockholders.

Series A Junior Participating Preferred Stock. There are no issued and outstanding shares of Series A Junior Participating Preferred Stock. It ranks junior to all series of preferred stock with respect to dividends and specified liquidation events. Dividends on this series are cumulative and do not bear interest, however, no dividend payment, or payment-in-kind, may be made to holders of common stock without declaring a dividend on this series equal to 1,000 times the aggregate per share amount declared on common stock. Upon the occurrence of specified liquidation events, the holders of this series shall be entitled to receive an aggregate amount per share equal to 1,000 times the aggregate amount to be distributed per share to holders of shares of common stock plus an amount equal to any accrued and unpaid dividends. Upon consolidation, merger or combination in which shares of common stock are exchanged for or changed into other securities or other assets, each share of this series shall be similarly exchanged into an amount per share equal to 1,000 times that into which each share of common stock is exchanged. The number of Series A Junior Participating Preferred Stock will be proportionately changed in the event the Company declares or pays a common stock dividend or effects a stock split of common stock.

Series A Preferred Stock. Following the Company's IPO, Series A convertible preferred stock was eliminated. Prior to the Company's IPO, Series A preferred consisted of 6,900,000 authorized shares with a stated purchase price of $4.17 per share. It ranked senior to the Company's common stock with respect to dividends and specified liquidation events.

Immediately prior to the Company's IPO, 6,594,725 shares of Series A preferred were issued and outstanding and converted into 2,592,317 shares of common stock.

In connection with the early capitalization of the Company, a mandatorily convertible note was issued for $1.9 million, which amount was classified in long-term liabilities, and pursuant to the terms of the note, automatically converted into 455,635 shares of Series A preferred immediately prior to the Company's IPO.

Series B Preferred Stock. Following the Company's IPO, Series B convertible preferred stock was eliminated. Prior to the Company's IPO, 51,951,418 shares were issued and outstanding and converted, along with $35.7 million of its 7% cumulative and unpaid dividends, into 23,795,362 shares of common stock. Immediately prior to the Company's IPO, Series B convertible preferred stock ranked senior to the Company's Series A preferred and common stock with respect to dividends and specified liquidation events.

In May 2004, the Company received final payment from investors of Series B preferred stock. Pursuant to EITF 98-5, *Accounting for Convertible Securities with Beneficial Conversion Features or Contingently Adjustable Conversion Ratios*, these issuances resulted in a beneficial conversion (deemed dividend) since the shares were issued with nondetachable conversion features which were deemed to be in-the-money at the commitment date. According to EITF 98-5, we are required to measure, but not record, the deemed dividend at the commitment date if the shares are convertible only upon the occurrence of a future event outside the control of the holder of such securities and contain conversion terms that change upon the occurrence of a future event. We measured deemed dividends of $2.6 million, $19.3 million and $11.3 million related to the 2002, 2003 and 2004 issuances of convertible Series B preferred stock, respectively. Additionally, pursuant to EITF 00-27, *Application of Issue 98-5 to Certain Convertible Instruments*, we measured and recorded at the IPO date additional deemed dividends of $3.1 million pertaining to the conversion of Series A and B convertible preferred stock into common stock at a discount to the IPO price related to the liquidation preference being converted less the underwriters' fees. Total deemed dividends recorded at the IPO date equaled $36.3 million.

In March and April 2004, the Company sold 50,000 and 95,918 shares, respectively, of Series B preferred stock for $5.00 per share to certain of its employees and recorded non-cash stock-based compensation expense accordingly.

Cumulative dividends not declared amounted to $17.1 million at December 31, 2003 and $35.7 million at the IPO closing date of December 15, 2004.

Common Stock. On January 30, 2002, the Company issued, subject to restrictions and adjusted for the 1-for-4.658 reverse stock split on the Company's IPO date, 1,800,548 shares of common stock to founding management and employees. On March 28, 2002, these common stockholders entered into a stockholders' agreement to restrict ownership of the shares with the following dual vesting provisions: (1) one share vesting for every $141.62355 received from investors in Series B Preferred Stock ("dollar vesting"), and (2) 20% vesting upon purchase and an additional 20% vesting each year for four years after purchase ("time vesting"). These management shares vest at the later to occur of time vesting and dollar vesting. Vesting ceases upon the occurrence of a liquidation event with respect to the Company, as defined in the agreement, or the sale of the Company. At each measurement date (the date the Company received funds from the investors in Series B preferred, i.e., the shares dollar vested), compensation expense was determined based on the then known number of shares that had dollar vested and, to the extent those shares were time vested, stock-based compensation expense was immediately recorded. The remaining charge was recorded as deferred compensation within stockholders' equity and amortized over the remaining time vesting service period in accordance with FASB Interpretations ("FIN") No. 28, *Accounting for Stock Appreciation Rights and Other Variable Stock Option or Award Plans.*

Of the 1,800,548 common shares issued to founding management and employees, 1,800,548 and 1,567,535 shares were dollar vested and 1,516,661 and 1,283,333 shares were time vested as of December 31, 2004 and 2003, respectively. The remaining time vesting will occur ratably through January 2006.

The following table reflects the activity in the Company's common and preferred stock. All common stock amounts reflect the reverse split that occurred in conjunction with our IPO.

	Period from January 7, 2002 (inception) through December 31, 2002	Year ended December 31, 2003	Year ended December 31, 2004
Series A Preferred Stock			
Outstanding:			
Shares at beginning of period	—	6,258,994	6,258,994
Shares issued under stock purchase agreements dated March 28, 2002	6,139,090	—	—
Shares issued for partial payment of mineral leasehold interests	119,904	—	—
Shares returned in settlement to terminate an exploration agreement	—	—	(119,904)
Shares issued upon conversion of convertible note payable	—	—	455,635
Shares converted into common stock immediately prior to IPO	—	—	(6,594,725)
Shares at end of period	6,258,994	6,258,994	—
Series B Preferred Stock			
Outstanding:			
Shares at beginning of period	—	21,100,000	45,145,700
Shares issued under Stock Purchase Agreement dated March 28, 2002	21,100,000	23,300,000	6,600,000
Shares issued for cash under Bill Barrett Corporation Employee Restricted Stock Purchase Plan	—	495,100	145,918
Shares issued for mineral leasehold interests	—	250,600	59,800
Shares converted into common stock immediately prior to IPO	—	—	(51,951,418)
Shares at end of period	21,100,000	45,145,700	—
Common Stock Outstanding:			
Shares at beginning of period	—	1,800,548	1,857,477
Restricted shares issued for cash to founding management and employees	1,800,548	—	—
Exercise of common stock options	—	56,929	128,135
Fractional shares after reverse split paid in cash	—	—	(21)
Shares issued upon conversion of Series A preferred stock	—	—	2,592,317
Shares issued upon conversion of Series B preferred stock and Series B cumulative dividends	—	—	23,795,362
Shares issued upon IPO	—	—	14,950,000
Shares at end of period	1,800,548	1,857,477	43,323,270

Accumulated Other Comprehensive Loss. The Company follows the provisions of SFAS No. 130, *Reporting Comprehensive Income*, which establishes standards for reporting comprehensive income. The components of accumulated other comprehensive loss and related tax effects for the periods from January 7, 2002 (inception) through December 31, 2004 were as follows:

	Gross	Tax Effect	Net of Tax
		(in thousands)	
Accumulated other comprehensive loss — January 7, 2002 (inception)	$ —	$ —	$ —
Change in fair value of hedges	(552)	204	(348)
Accumulated other comprehensive loss — December 31, 2002	(552)	204	(348)
Change in fair value of hedges	(6,986)	2,585	(4,401)
Reclassification adjustment for realized losses on hedges included in net loss	552	(204)	348
Accumulated other comprehensive loss — December 31, 2003	(6,986)	2,585	(4,401)
Change in fair value of hedges	(5,665)	2,096	(3,569)
Reclassification adjustment for realized losses on hedges included in net loss	6,986	(2,585)	4,401
Accumulated other comprehensive loss — December 31, 2004	$ (5,665)	$ 2,096	$ (3,569)

10. Common Stock, Stock Options and Other Employee Benefits

As described below, we record non-cash stock-based compensation related to two separate equity awards: restricted common stock and stock option awards. Non-cash stock-based compensation has been reported as a separate expense in the Statements of Operations and should be considered a component of general and administrative expense.

Common Stock. On January 30, 2002, the Company issued, subject to restrictions, 1,800,548 shares of common stock to founding management and employees. On March 28, 2002, these common stockholders entered into a stockholders' agreement to restrict ownership of the shares with the following dual vesting provisions: (1) one share vesting for every $141.62355 received from investors in Series B Preferred Stock ("dollar vesting"), and (2) 20% vesting upon purchase and an additional 20% vesting each year for four years after purchase and continued service with the Company ("time vesting"). The 1,800,548 shares of common stock fully dollar vested in 2004. Vesting ceases upon the occurrence of a liquidation event with respect to the Company, as defined in the agreement, or the sale of the Company. At each measurement date (the date the Company received funds from the investors in Series B preferred, i.e., the shares dollar vested), compensation expense was determined based on the then known number of shares that had dollar vested and, to the extent those shares were time vested, stock-based compensation expense was immediately recorded. The remaining charge was recorded as deferred compensation within stockholders' equity and amortized over the remaining time vesting service period in accordance with FIN No. 28. Based on the fair value vested for these common stock issuances, the Company recorded $1.2 million, $2.6 million, and $2.0 million of stock-based compensation expense in the period from January 7 (inception) through December 31, 2002 and the years ended December 31, 2003 and 2004, respectively; none of the stock-based compensation has been capitalized, and the related tax benefit recognized was less than $0.1 million in each of the respective periods. We had $0.5 million in deferred compensation related to this common stock recorded in stockholders' equity as of December 31, 2004, which will be recognized ratably until January 31, 2006.

A summary of activity for the restricted common stock as of December 31, 2004, and changes during the year then ended, is presented below:

	Shares	Weighted Average Fair Value
Nonvested at January 1, 2004	750,228	$2.53
Granted	—	N/A
Vested	(466,341)	$5.35
Forfeited or expired	—	N/A
Nonvested at December 31, 2004	283,887	$3.26

Stock Options. In January 2002, the Company adopted a stock option plan to benefit key employees, directors and non-employees. This plan was amended and restated in its entirety by the Amended and Restated 2002 Stock Option Plan (the "2002 Option Plan"). The aggregate number of shares which the Company may issue under the 2002 Option Plan may not exceed 1,642,395 shares of the Company's common stock. Under the 2002 Option Plan, up to 1,180,807 shares are designated as Tranche A and up to 461,588 shares are designated as Tranche B. Until our IPO, Tranche A options could be granted with an exercise price of not less than $30.28 per share, and Tranche B options could be granted with an exercise price of not less than $0.20551 per share. Options granted under the 2002 Option Plan expire ten years from the grant date. The options are subject to the following time vesting provisions — 40% on the first anniversary of the date of grant and 20% on subsequent anniversaries of the date of grant subject to the acceleration and other specified occurrences also addressed in Note 9. Options granted on or before February 3, 2003 vested 20% on date of grant and 20% on each of the next four anniversaries of the date of grant. Options granted under the 2002 Stock Option Plan were subject to equity vesting provisions by having all options that are outstanding vest proportionately based on the total number of shares of common stock outstanding assuming the conversion of our outstanding Series A and Series B preferred stock. As of May 12, 2004, all options under the 2002 Stock Option Plan were equity vested.

For options granted before October 1, 2004, on each measurement date (principally, the dates the Company received funds from the investors in Series B, i.e., the shares equity vest), compensation expense was determined based on the then known number of options that had equity vested and to the extent those options were time vested, stock-based compensation expense was immediately recorded. The remaining charge was recorded as deferred compensation within stockholders' equity and amortized over the remaining time vesting service period in accordance with FIN No. 28.

Concurrent with our IPO on December 9, 2004, we offered to the 62 employees and directors that held Tranche A options an exchange of their options for new Tranche A options equal in number to 92.6% of their original Tranche A options with a new exercise price equal to the IPO price of $25.00 per share and an expiration date of December 9, 2011. The vesting of the exchanged options did not change. All employees accepted this exchange ratio based on a fair value neutral exchange computed using a Black-Scholes-Merton model and, as such, the Company recorded no additional stock based compensation expense.

In December 2003, the Company adopted its 2003 Stock Option Plan (the "2003 Option Plan") to benefit key employees, directors and non-employees. In April 2004, the 2003 Option Plan was approved by the Company's stockholders. The aggregate number of shares which the Company may issue under the 2003 Option Plan may not exceed 42,936 shares of the Company's common stock. Options granted under the 2003 Option Plan expire ten years from the date of grant with an exercise price not less than 100% of the fair market value, as defined in the 2003 Option Plan, of the underlying common shares on the date of grant. Options granted under the 2003 Option Plan vest 25% on the first anniversary of the date of grant, and 25% on each of the next three anniversaries of the date of grant.

On December 1, 2004, our shareholders approved the 2004 Stock Incentive Plan (the "2004 Incentive Plan") for the purpose of enhancing our ability to attract and retain officers, employees, directors and consultants and to provide such persons with an interest in the Company parallel to our stockholders. The 2004 Incentive Plan provides for the grant of stock options (including incentive stock options and non-qualified stock options) and other awards (including performance units, performance shares, share awards, restricted stock, restricted stock units, and stock appreciation rights, or SARs). The maximum number of award that may be granted under the 2004 Incentive Plan is 4,900,000. In addition, the maximum number of awards granted to a participant in any one year is 1,225,000.

Options to purchase 1,074,000 shares were granted in December 2004 that expire seven years from grant date and vest 25% on the first anniversary of the date of grant, and 25% on each of the next three anniversaries of the date of grant. We did not grant any other awards under the 2004 Incentive Plan during 2004. Unless terminated earlier by our board of directors, the 2004 Incentive Plan will terminate on June 30, 2014. Upon an event constituting a "change in control" (as defined in the 2004 Incentive Plan) of the Company, all options and SARs will become immediately exercisable in full. In addition, in such an event, performance units will become immediately vested and restrictions on restricted stock awards will lapse.

Our compensation committee may grant awards on such terms, including vesting and payment forms, as it deems appropriate in its discretion, however, no award may be exercised more than 10 years after its grant (five years in the case of an incentive stock option granted to an individual who possesses more than 10% of the total combined voting power of all classes of stock of the Company). The purchase price or the manner in which the exercise price is to be determined for shares under each award will be determined by the compensation committee and set forth in the agreement. However, the exercise price per share under each award may not be less than 100% of the fair market value of a share on the date the award is granted (110% in the case of an incentive stock option granted to an eligible individual who possesses more than 10% of the total combined voting power of all classes of stock of the Company).

Currently, our practice is to issue new shares upon stock option exercise, and we do not expect to repurchase any shares in the open market to settle any such exercises. In the period January 7, 2002 (inception) through December 31, 2002 and the years ended December 31, 2003 and 2004, we used no cash to repurchase any stock related to any option exercises.

In accordance with SFAS No. 123R, the fair value of each option award under all our plans is estimated on the date of grant using a Black-Scholes-Merton pricing model that incorporates the assumptions noted in the following table. Because our common stock has only recently become publicly traded, we have estimated expected volatilities based on an average of volatilities of similar sized Rocky Mountain oil and gas companies whose common stock is or has been publicly traded for a minimum of five years and other similar sized oil and gas companies who recently became publicly traded. For options granted when we were a nonpublic company, we adopted the minimum value method under SFAS No. 123, which uses 0% volatility. Given our stage of growth and requirement for capital investment, we used a 0% expected dividend yield, which is comparable to most of our peers in the industry. The expected term ranges from 1.25 years to 5.0 years based on the 25% on each anniversary date after grant vesting period and factoring in potential blackout dates and historic exercises, with a weighted average of 2.9 years. The risk-free rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect on the date of grant. We estimated a 4% annual compounded forfeiture rate based on historical employee turnover.

	Period from January 7, 2002 (inception) through December 31, 2002	Year Ended December 31, 2003	Year Ended December 31, 2004
Weighted Average Volatility	0%	0%	37%
Expected Dividend Yield	0%	0%	0%
Expected Term (in years)	4.0	4.0	3.0
Risk-free Rate	2.8%	2.5%	3.1%

A summary of option activity under all our plans as of December 31, 2004, and changes during the year then ended, is presented below:

	Shares	Weighted-average exercise price	Weighted-average remaining contractual term	Aggregate intrinsic value
Outstanding at January 1, 2004	1,562,851	$ 22.67	8.83	$ 2,414,400
Granted	2,237,596	24.61	7.07	231,221
Exercised	(128,135)	0.41	8.50	1,486,532
Forfeited or expired	(1,187,821)	30.21	7.89	-
Outstanding at December 31, 2004	2,484,491	$ 21.96	7.10	$ 24,926,429
Exercisable at December 31, 2004	652,582	$ 23.18	7.01	$ 5,749,684

The per share weighted-average grant-date fair value of options granted during the period January 7, 2002 (inception) through December 31, 2002 and the years ended December 31, 2003 and 2004 was $0.36, $ 1.31 and $7.11, respectively, and the total intrinsic value of options exercised during the same periods was $0 million, $0.3 million and $1.5 million, respectively. Related to stock option exercises, we received no cash in the period January 7, 2002 (inception) through December 31, 2002 and less than $0.1 million in each of the years ended December 31, 2003 and 2004. The related tax benefit was nominal. In addition, no cash was used to settle stock option exercises during the period January 7, 2002 (inception) through December 31, 2002 and for the years ended December 31, 2003 and 2004.

We recorded non-cash stock based compensation related to option awards of $0.1 million, $0.6 million, and $0.7 million in the period January 7, 2002 (inception) through December 31, 2002, and the years ended December 31, 2003 and 2004, respectively. None of the stock-based compensation has been capitalized, and the related tax benefit recognized was less than $0.1 million in each respective period. As of December 31, 2004, there was $7.4 million of total unrecognized compensation costs related to nonvested stock option grants recorded in deferred compensation. That cost is expected to be recognized over a weighted-average period of 1.9 years.

The following table provides additional quarterly information related to options granted during the period from January 7 (inception) through December 31, 2002 and the years ended December 31, 2003 and 2004:

Options granted in the Quarters Ended	Number of Options Granted	Weighted-Average Exercise Price
31-Mar-02	0	N/A
30-Jun-02	0	N/A
30-Sep-02	247,969	$ 0.41
	945,719	30.28
31-Dec-02	16,102	0.41
	27,910	30.28
31-Mar-03	176,584	0.41
	163,703	30.28
30-Jun-03	16,102	0.41
	29,520	30.28
30-Sep-03	3,757	0.41
	7,514	30.28
31-Dec-03	9,446	1.30
	17,497	30.28
31-Mar-04	8,802	2.14
	20,396	4.66
	20,396	30.28
30-Jun-04	11,808	4.66
	215	30.28
30-Sep-04	10,735	11.60
	215	11.60
31-Dec-04	1,074,000	25.01

Other Employee Benefits-401(k) Savings. The Company has an employee directed 401(k) savings plan (the "401(k) Plan") for all eligible employees over the age of 21. Employees become eligible the quarter following the beginning of their employment. Under the 401(k) Plan, employees may make voluntary contributions based upon a percentage of their pretax income. The Company matches 100% of the employee contribution, up to 4% of the employee's pretax income. The Company made matching contributions of less than $0.1 million for the period from January 7, 2002 (inception) through December 31, 2002 and $0.2 million and $0.4 million for the years ended December 31, 2003 and 2004, respectively.

11. Transactions with Related Parties

A director of the Company is a principal at a company affiliated with the lead arranger and agent for the credit facilities noted in Note 5 above and the company that was an underwriter in our IPO.

A director of the Company is a managing director of a company affiliated with the company which wholly owns the counterparty to the natural gas swaps noted in Note 7 above, the company that was the sole lead arranger and administrative agent for the senior subordinated credit and guaranty agreement as discussed in Note 5 above, and the company that was the lead underwriter in our IPO.

In management's opinion, the terms obtained in the above transactions were provided on terms at least as favorable to the Company as could be obtained from non-related sources.

12. Significant Customers and Other Concentrations

Significant Customers. During 2002, purchases by The Williams Companies, Inc. and ConocoPhillips Holding Company accounted for 59.2% and 15.6%, respectively, of the Company's total oil and gas production revenues. During 2003, ONEOK Inc. accounted for 38.6% and two wholly-owned subsidiaries of Xcel Energy Inc., the names of which are Public Service Co. of Colorado and Cheyenne Light, Fuel and Power Co., accounted for a total of 10.2% of the Company's oil and gas production revenues. During 2004, ONEOK Inc. accounted for 37.5% of the Company's oil and gas production revenues. Management believes that the loss of any individual purchaser would not have a long-term material adverse impact on the financial position or results of operations of the Company.

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

The Company operates in the exploration, development and production phase of the oil and gas industry. Its receivables include amounts due from purchasers of oil and gas production and amounts due from joint venture partners for their respective portions of operating expense and exploration and development costs. The Company believes that no single customer or joint venture partner exposes the Company to significant credit risk. While certain of these customers and joint venture partners are affected by periodic downturns in the economy in general or in their specific segment of the natural gas or oil industry, the Company believes that its level of credit-related losses due to such economic fluctuations has been and will continue to be immaterial to the Company's results of operations in the long-term. Trade receivables are generally not collateralized. The Company analyzes customers' and joint venture partners' historical credit positions and payment history prior to extending credit.

Concentrations of Credit Risk. Derivative financial instruments that hedge the price of oil and gas are generally executed with major financial or commodities trading institutions which expose the Company to market and credit risks and may, at times, be concentrated with certain counterparties or groups of counterparties. Although notional amounts are used to express the volume of these contracts, the amounts potentially subject to credit risk, in the event of non—performance by the counterparties, are substantially smaller. The credit worthiness of counterparties is subject to continuing review and full performance is anticipated. The Company's policy is to execute financial derivatives only with major financial institutions.

13. Commitments and Contingencies

The Company leases office space and certain equipment under non-cancelable operating leases. Office lease expense for the period from January 7, 2002 (inception) through December 31, 2002 and for the years ended December 31, 2003 and 2004 was $159,000, $517,000 and $878,000, respectively. Additionally, the Company has entered into various long-term agreements for telecommunication service.

In 2004, the Company entered into three firm transportation agreements. The first agreement provides guaranteed capacity for 8,500 MMBtu per day at a monthly charge of $45,000 through February 28, 2005. The second agreement provides guaranteed capacity of 9,000 MMBtu per day for the first 12 years and 5,000 MMBtu per day for the last year at a fixed fee of $0.34 per MMBtu beginning in February 2005. The third firm transportation agreement is for 12,000 MMBtu/d of guaranteed pipeline capacity at a monthly charge of $94,000 per month for ten years beginning upon the completion of Questar's upgrade of its pipeline in the Piceance Basin, which is expected to be completed in November 2005.

Future minimum annual payments under such leases and agreements are as follows (in thousands):

2005	$ 2,196
2006	3,201
2007	3,174
2008	3,156
2009	2,332
Thereafter	15,485
Total	$29,544

In July 2004, the Company entered into an exploration and development agreement with the Ute Indian Tribe of the Uintah and Ouray Reservation to explore for and develop oil and natural gas on approximately 125,000 of their net undeveloped acres. Pursuant to this agreement, we are required to drill one deep and two shallow wells by December 31, 2005. If we fail to drill the 2005 well commitments, we are required to pay the Ute Indian Tribe $1.8 million. This commitment is not included in the table above.

14. Supplementary Oil and Gas Information (unaudited)

Costs Incurred. Costs incurred in oil and gas property acquisition, exploration and development activities and related depletion per equivalent unit-of-production were as follows:

	Period from January 7, 2002 (inception) through December 31, 2002	Year Ended December 31, 2003	Year Ended December 31, 2004
	(in thousands, except amortization data)		
Acquisition costs:			
Unproved properties	$15,178	$17,581	$73,469
Proved properties	127,528	30,979	79,440
Exploration costs	5,925	41,846	98,751
Development costs	5,123	94,637	93,304
Asset retirement obligation	1,039	2,936	7,153
Total costs incurred	$154,793	$187,979	$352,117
Amortization per Mcfe of production	$1.37	$1.63	$2.12

Supplemental Oil and Gas Reserve Information. The reserve information presented below is based on estimates of net proved reserves as of December 31, 2002, 2003, and 2004 that were prepared by internal petroleum engineers in accordance with guidelines established by the Securities and Exchange Commission and were reviewed by Ryder Scott Company and Netherland, Sewell & Associates, Inc., independent petroleum engineering firms.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Analysis of Changes in Proved Reserves. The following table sets forth information regarding the Company's estimated net total proved and proved developed oil and gas reserve quantities, excluding reserves for oil and gas properties held for sale:

	Oil (MBbls)	Gas (MMcf)
Proved reserves:		
Inception, January 7, 2002	—	—
Purchases of oil and gas reserves in place	2,914	100,313
Extension, discoveries and other additions	—	7,833
Production	(30)	(6,371)
Balance, December 31, 2002	2,884	101,775
Purchases of oil and gas reserves in place	918	31,798
Extension, discoveries and other additions	754	100,024
Revisions of previous estimates	(342)	(33,902)
Sales of reserves	—	(2,506)
Production	(328)	(16,315)
Balance, December 31, 2003	3,886	180,874
Purchases of oil and gas reserves in place	201	48,949
Extension, discoveries and other additions	1,846	87,098
Revisions of previous estimates	440	(28,490)
Sales of reserves	(161)	(1,691)
Production	(474)	(28,864)
Balance, December 31, 2004	5,738	257,876
Proved developed reserves:		
December 31, 2002	1,888	78,155
December 31, 2003	3,166	108,569
December 31, 2004	4,249	153,118

Standardized Measure. Estimated discounted future net cash flows and changes therein were determined in accordance with SFAS No. 69, *Disclosures about Oil and Gas Producing Activities.* Certain information concerning the assumptions used in computing the valuation of proved reserves and their inherent limitations are discussed below. The Company believes such information is essential for a proper understanding and assessment of the data presented.

Future cash inflows are computed by applying year-end prices of oil and gas relating to the Company's proved reserves to the year-end quantities of those reserves. Year-end calculations were made using prices of $29.14, $32.98, and $43.46 per Bbl for oil and $3.33, $5.81, and $5.52 per Mcf for gas for 2002, 2003, and 2004, respectively. The Company also records an overhead expense of $100 per month per operated well in the calculation of its future cash flows.

The assumptions used to compute estimated future cash inflows do not necessarily reflect the Company's expectations of actual revenues or costs, nor their present worth. In addition, variations from the expected production rate also could result directly or indirectly from factors outside of the Company's control, such as unexpected delays in development, changes in prices or regulatory or environmental policies. The reserve valuation further assumes that all reserves will be disposed of by production. However, if reserves are sold in place, additional economic considerations could also affect the amount of cash eventually realized.

Future development and production costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions.

Future income tax expenses are computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pre-tax net cash flows relating to the Company's proved oil and gas reserves. Permanent differences in oil and gas related tax credits and allowances are recognized.

A 10% annual discount rate was used to reflect the timing of the future net cash flows relating to proved oil and gas reserves.

The following table presents the standardized measure of discounted future net cash flows related to proved oil and gas reserves.

	December 31,		
	2002	2003	2004
		(in thousands)	
Future cash inflows	$422,935	$1,179,562	$1,722,369
Future production costs	(110,513)	(281,355)	(502,269)
Future development costs	(49,430)	(112,452)	(211,464)
Future income taxes	(38,535)	(176,850)	(223,884)
Future net cash flows	224,457	608,905	784,752
10% annual discount	(70,909)	(204,085)	(318,643)
Standardized measure of discounted future net cash flows	$153,548	$ 404,820	$ 466,109

A summary of changes in the standardized measure of discounted future net cash flows is as follows:

	Period from January 7, 2002 (inception) through December 31, 2002	Year ended December 31, 2003	Year ended December 31, 2004
		(in thousands)	
Standardized measure of discounted future net cash flows, beginning of period	$ —	$153,548	$404,820
Sales of oil and gas, net of production costs and taxes	(11,653)	(61,017)	(137,606)
Extensions, discoveries and improved recovery, less related costs	13,878	268,258	237,683
Quantity revisions	—	(116,979)	(70,074)
Price revisions	—	128,745	(22,382)
Net changes in estimated future development costs	—	(1,625)	9,316
Accretion of discount	—	17,866	52,082
Purchases of reserves in place	176,433	50,717	83,171
Sales of reserves	—	3,650)	(4,535)
Changes in production rates (timing) and other	—	59,852	(76,425)
Net changes in future income taxes	25,110)	(90,895)	(9,941)
Standardized measure of discounted future net cash flows, end of period	$ 153,548	$404,820	$466,109

15. Quarterly Financial Data (unaudited)

The following is a summary of the unaudited financial data for each quarter presented. The income (loss) before income taxes, net income (loss), and net income (loss) per common share for each of the quarters for the years ended December 31, 2003 and 2004.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
		(in thousands, except per share data)		
Year ended December 31, 2003:				
Total revenues	$ 12,945	$ 16,378	$ 18,789	$ 27,324
Loss before income taxes	(1,160)	(412)	(1,265)	(1,461)
Net loss	(1,030)	(343)	(1,247)	(1,358)
Net loss per common share, basic and diluted	(4.48)	(4.10)	(5.18)	(5.43)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
		(in thousands, except per share data)		
Year ended December 31, 2004:				
Total revenues	$ 36,441	$ 42,399	$ 42,675	$ 48,465
Income (loss) before income taxes	8,187	5,251	(6,103)	(13,476)
Net income (loss)	4,737	3,035	(3,940)	(9,098)
Net income (loss) per common share, basic	0.01	(0.03)	(6.08)	(4.33)
Net income (loss) per common share, diluted	0.01	(0.03)	(6.08)	(4.33)

Corporate Office

1099 Eighteenth Street, Suite 2300
Denver, Colorado 80202
Telephone: 303-293-9100 Fax: 303-291-0420
Internet: www.billbarrettcorp.com
NYSE: BBG

Bill Barrett Corporation

Investor Relations

Bob Howard, Executive VP—Finance and Investor Relations
Jim Felton, Manager—Investor Relations

Annual Stockholders' Meeting

Our annual stockholders' meeting will be held at 9:30 a.m. (MDT) on Thursday, May 19, 2005 at the Magnolia Hotel Ballroom, 817 Seventeenth Street, Denver, Colorado 80202

Transfer Agent

Mellon Investor Services LLC
Overpeck Center, 85 Challenger Road
Ridgefield Park, NJ, 07660-2108
1-800-851-9677
www.melloninvestor.com/isd

Independent Auditors

Deloitte & Touche LLP
Denver, Colorado 80202

Legal Counsel

Patton Boggs LLP
Denver, Colorado 80264

Reservoir Engineers

Netherland Sewell & Associates, Inc.
Dallas, Texas

Ryder Scott Company, L.P.
Denver, Colorado

Glossary

Bbl:	Barrel of oil
Bcf:	Billion cubic feet
Bcfe:	Billion cubic feet of gas equivalent
Boe:	Barrel of oil equivalent
Bopd:	Barrels of oil per day
Mcf:	Thousand cubic feet (of gas)
MMcf:	Million cubic feet
MMcfe:	Million cubic feet equivalent
MMcfe/d:	Million cubic feet equivalent per day
MMBtu:	Million British thermal units
MBoe:	Thousand barrels of oil equivalent
MMBoe:	Million barrels of oil equivalent
MBoe/d:	Thousand barrels of oil equivalent per day
MBbls:	Thousand barrels
MBbls/d:	Thousand barrels per day
MMBbls:	Million barrels
Tcf:	Trillion cubic feet

One barrel of oil is the energy equivalent of six Mcf of natural gas.

Non-GAAP Measure

Discretionary cash flow is computed as net loss plus depreciation, depletion, amortization and impairment expenses, deferred income taxes, exploration expenses, non-cash stock-based compensation, losses (gains) on sale of properties, and certain other non-cash charges. The non-GAAP measure of discretionary cash flow is presented because management believes that it provides useful additional information to investors for analysis of the Company's ability to internally generate funds for exploration, development and acquisitions. In addition, discretionary cash flow is widely used by professional research analysts and others in the valuation, comparison and investment recommendations of companies in the oil and gas exploration and production industry, and many investors use the published research of industry research analysts in making investment decisions. Discretionary cash flow should not be considered in isolation or as a substitute for net income, income from operations, net cash provided by operating activities or other income, profitability, cash flow or liquidity measures prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). Because discretionary cash flow excludes some, but not all, items that affect net income and net cash provided by operating activities and may vary among companies, the discretionary cash flow amounts presented may not be comparable to similarly titled measures of other companies. For a reconciliation of discretionary cash flow for the years ended December 31, 2003 and 2004 to net income for those periods, refer to our Form 8-K filed March 11, 2005.

Forward Looking Statements

This report contains forward-looking statements regarding Bill Barrett Corporation's future plans and expected performance based on assumptions the Company believes to be reasonable. A number of risks and uncertainties could cause actual results to differ materially from these statements, including, without limitation, the success rate of exploration efforts and the timeliness of development activities, fluctuations in oil and gas prices, and other risk factors described in the Company's accompanying Form 10-K for the year ended December 31, 2004.

The Company has filed as exhibits to its Annual Report on Form 10-K for the fiscal year ended December 31, 2004 the certifications of its Chief Executive Officer and Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act. Because the Company's common stock first listed on the New York Stock Exchange in December 2004, the Company was not required to submit to the New York Stock Exchange during 2004 an Annual CEO Certification required by Section 303A.12(a) of the New York Stock Exchange Listed Company Manual.

Bill Barrett Corporation

BBG
LISTED
NYSE

1099 Eighteenth Street, Suite 2300
Denver, Colorado 80202
Telephone: 303-293-9100
Fax: 303-291-0420
www.billbarrettcorp.com