Bill Barrett Corporation

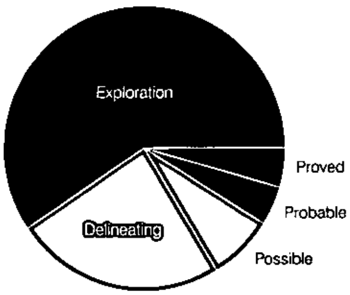
2006 ANNUAL REPORT

a **premier**

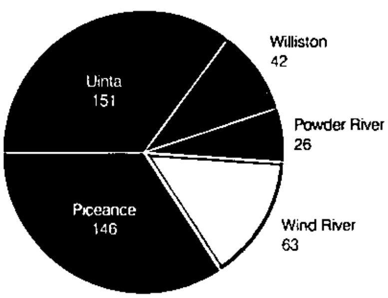
Rockies E&P Company

areas of operation

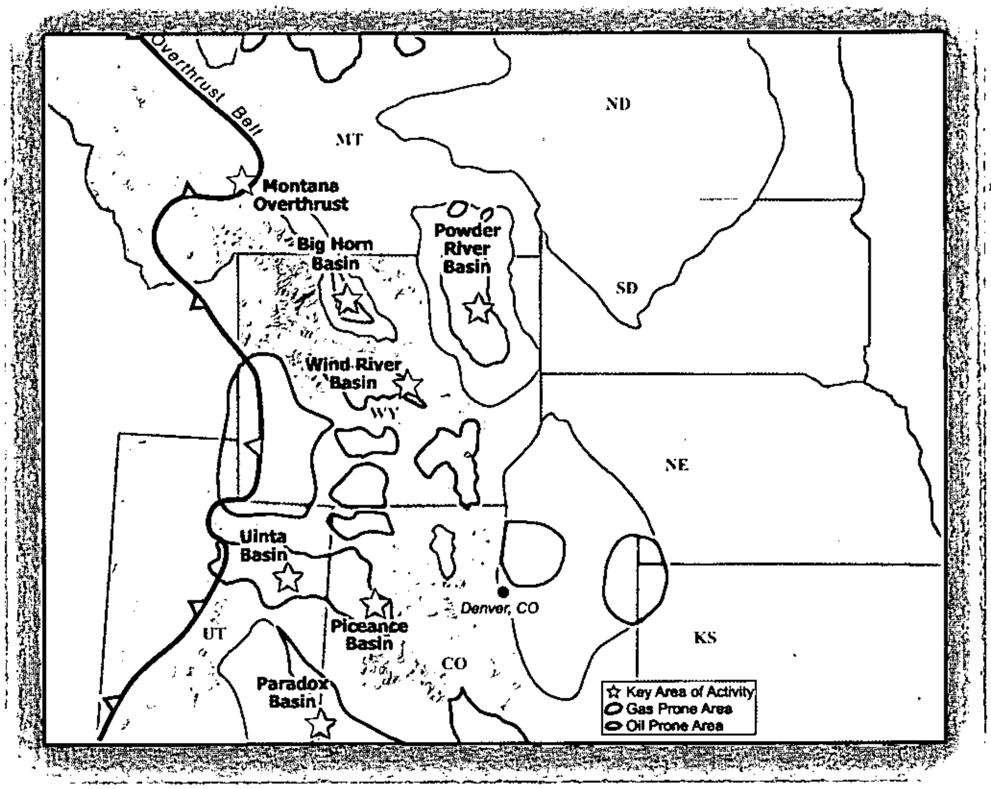
8-10 Tcfe
Unrisked Potential



428 Bcfe
Net Proved Reserves



As of December 31, 2006



corporate profile

Bill Barrett Corporation is a Rocky Mountain exploration and production company that seeks to enhance shareholder value by executing a long-term growth strategy. Specifically, we strive to:

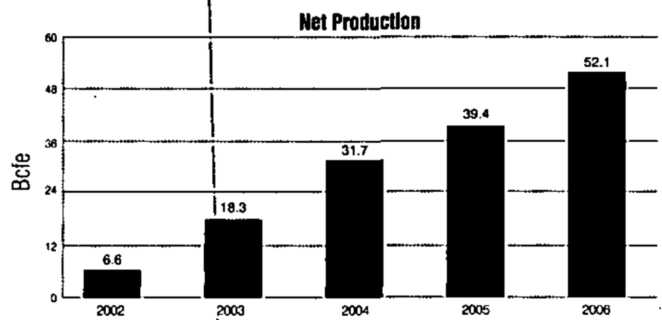
- Focus on long-term reserve and production growth through active drilling
- Develop low-risk, multi-year drilling inventories
- Build multiple, diverse exploration plays that have high-impact, high-return potential
- Apply existing and emerging technologies to reduce exploration risk and enhance recoveries
- Maintain financial flexibility to pursue growth strategy

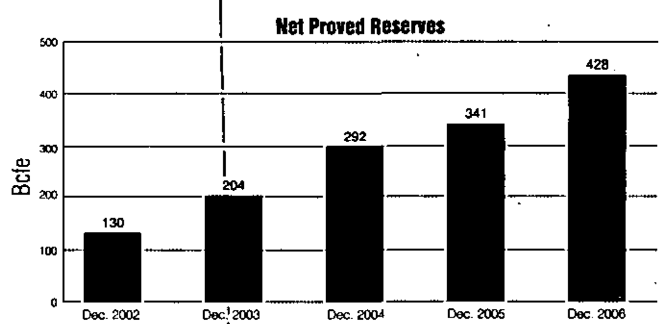
dear shareholders

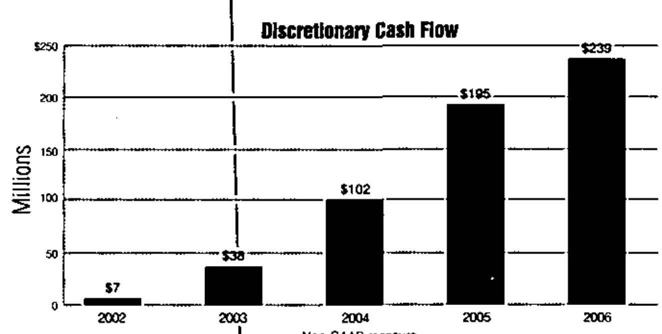
Effective execution of our development and exploration programs made 2006 a year of significant achievement and growth for the Company. We increased production by 32% and proved reserves by 26% over 2005 and, as we continue to bring visibility to our development projects, total proved, probable and possible (3P) resources increased to 2 Tcfe. That performance generated record earnings and cash flow per share.

Factors driving that performance include an active drilling program on our development projects and we added to our low-risk Powder River Basin prospects with a May 2006 acquisition. We continued exploration success in our West Tavaputs deep, Lake Canyon, and Bullfrog projects. We added two key executives and long-term Rockies veterans to our team—Joe Jaggers as Chief Operating Officer and President, and Bob Howard as our new Chief Financial Officer. These are two men that exemplify the focus and dedication to our original vision when we started the Company five years ago of creating the premier exploration and production company in the Rockies.

2006 was not without its challenges. Natural gas prices dropped nearly 40% in 2006 (and our stock price suffered), while costs for drilling and oilfield services remained high.

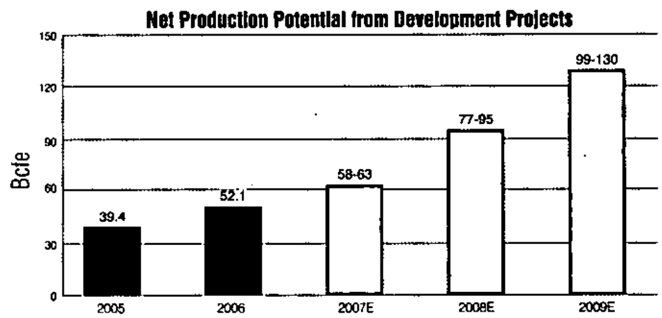






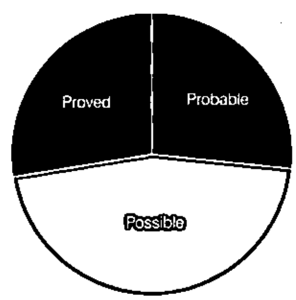
Because commodity price volatility is part of our business, we use hedging to mitigate risk of commodity price swings. We are hedging 60-70% of our 2007 production at attractive prices, which helps protect 2007's $425-450 million capital program with more assured cash flows and project returns. We continue adding firm transportation and sales contracts to provide takeaway capacity for our increasing gas production. We have contracted with new entrants to our basins in the drilling and service businesses to take advantage of competitive pricing. We are financially strong and flexible, concluding 2006 with a low debt to capitalization ratio.

Looking to increase shareholder value, we are pursuing continued double digit growth in 2007 and beyond generated by our development programs in West Tavaputs, Piceance Basin, and Powder River Basin, where we recognize 1.7 Tcfe of 3P resources.



At West Tavaputs, located in the Uinta Basin in Utah, we grew production by 209% in 2006 from our drilling in both the shallow and deeper horizons. Once we receive a Record of Decision to our Environmental Impact Statement in late 2007 or early 2008, we anticipate significant production and reserve growth from full field development of this nearly 800 Bcfe 3P resource base.

2.0 Tcfe
3P Resources



We are actively testing a 10-acre drilling program this year in the Piceance Basin of Colorado, downspacing from the 20-acre spacing we have been drilling thus far. In other areas in the Piceance Basin, 10-acre spacing has enhanced recoveries for the estimated 80 Bcfe per square mile gas in place found in one of this country's most prolific gas-producing areas.

In our low risk coalbed methane (CBM) project in the Powder River Basin of Wyoming, we will continue drilling the thick, deep Big George coals. We anticipate strong production growth in late 2007 and 2008 as the coals continue to dewater and gas production begins.

These development projects represent just a part of a strategy that I feel clearly separates us from our Rockies peers. Our array of large scale, high-impact exploration programs represents several trillion cubic feet of unrisked upside to the Company's resource base. Our appetite for exploration remains a critical component of the strategic vision behind the Company's formation five years ago.

In just the last two years, new discoveries at West Tavaputs deep and Lake Canyon in the Uinta Basin, as well as in the Wind River Basin, have helped us delineate potential new fields. A prime example of our delineation efforts is Lake Canyon, where we and our partner were successful in finding hydrocarbons in all seven wells drilled thus far. We plan to drill up to 24 wells in 2007 to further determine the economic potential of this oil prone area.

In the Wind River Basin, we are seeking a partner to keep one rig continuously drilling the deep Lakota, Muddy and Frontier to further explore the higher risk, high potential we had in two earlier discoveries.

In 2007, we plan to test four high-profile exploration prospects in the Big Horn Basin, Montana Overthrust, Paradox Basin, and Uinta Basin. Success in any one of these has the potential to significantly increase the size of the Company's reserve base.

In the Big Horn Basin, we are testing a potential multi-Tcf basin-centered gas play in an area traditionally considered an oil-prone basin. In our Montana Overthrust prospect, over 150 square miles of 3-D seismic survey data has identified numerous large four-way structures. We plan two exploration test wells there this summer. In our Yellow Jacket shale prospect in the Paradox Basin, we have drilled, cored, and set casing on two wells. We are pursuing a shale concept in the Hook area of the Uinta Basin and, in the neighboring Woodside area, we plan to test wells to explore a four-way closure.

Another of our strategic objectives is the use of technology. For example, we have over 2,700 square miles of 3-D seismic data for our prospects to help our geologic understanding and mitigate drilling risk. The application of evolving completion technology was instrumental to improving our Piceance Basin well performance.

We consistently review our portfolio of prospects to ensure they all fit within our strategic objectives. We will add with bolt-on acquisitions similar to our May 2006 Powder River Basin purchase, or divest properties similar to our decision to sell our Williston properties. Thus, we constantly strive to deploy capital in an attempt to maximize long-term value to shareholders.

These first five years for our Company have gone by fast, and I hope you agree that we have accomplished much of what we set out to do here in the Rockies. We are well-positioned to continue delivering a clean, efficient and domestic energy supply to our country's economy. With the Rockies Express Pipeline adding 1.8 Bcf per day capacity from Colorado to Ohio in 2009, we see improved realized prices for our production. In 2006, the Rockies region emerged, for the first time ever, as the country's most prolific gas producing region, eclipsing the Gulf of Mexico. Additionally, the Department of Energy projects the Rockies to be one of the few regions in the country to show any significant growth in natural gas production over the next 20 years. Many of you are aware that it is precisely this ascendance of Rockies gas production that the Company was founded on.

With your continued support, we will be able to develop the potential of the natural gas resources of the Rockies as we continue to become a premier Rockies E&P company. I thank you, the shareholders, for investing with us.

Sincerely,

Fredrick J. Barrett
Chairman of the Board and Chief Executive Officer
March 16, 2007

financial & operating results

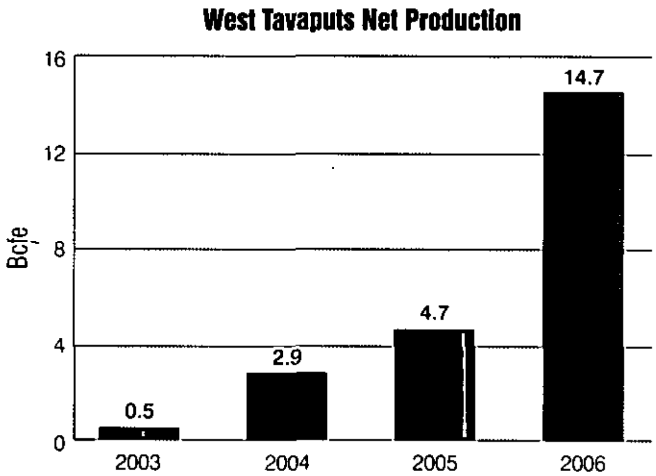
	2004	2005	2006
Proved Reserves and Acreage			
Natural Gas, Bcf	257.8	306.0	377.7
Oil, MMBbls	5.7	5.8	8.5
Natural Gas Equivalents, Bcfe[1]	292.3	341.0	428.4
Percent Developed	61%	61%	58%
Percent Natural Gas	88%	90%	88%
Pre-Tax PV-10, millions	$592	$1,050	$603
Net Undeveloped Acreage (rounded)	971,000	1,210,000	1,269,000
Production			
Bcfe	31.7	39.4	52.1
Average Daily Production, MMcfe	86.6	108.0	142.8
Percent Natural Gas	91%	92%	92%
Average Realized Prices			
Natural Gas Prices, including hedge effect, $/Mcf	$5.10	$7.16	$6.40
Oil Prices, including hedge effect, $/Bbl	$39.49	$46.68	$53.50
Operating Statistics			
Reserve Replacement	378%	224%	267%
Capital Expenditures and Acquisitions, millions	$347	$344	$423
Producing Wells, gross/net	743/553	940/738	1,147/838
Wells Drilled, gross/net	287/259	323/233	224/136
Financial Data			
Net Income (Loss), millions	($5)	$24	$62
Earnings Per Share (diluted)	N/A	$0.55	$1.40
Discretionary Cash Flow[2], millions	$102	$195	$239
Production Revenue ($/Mcfe)	$5.23	$7.21	$6.60
Lease Operating Expenses and Gathering and Transportation ($/Mcfe)	$0.65	$0.80	$0.87
Production Taxes ($/Mcfe)	$0.63	$0.85	$0.50
G&A, excluding non-cash stock-based compensation[2] ($/Mcfe)	$0.57	$0.62	$0.53
Depletion, Depreciation, and Amortization ($/Mcfe)	$2.15	$2.27	$2.69
Discretionary Cash Flow[2] ($/Mcfe)	$3.23	$4.96	$5.39
Finding and development cost[2] ($/Mcfe)	$2.81	$3.78	$2.44

[1] *One Barrel of oil is the energy equivalent of six Mcf of natural gas*

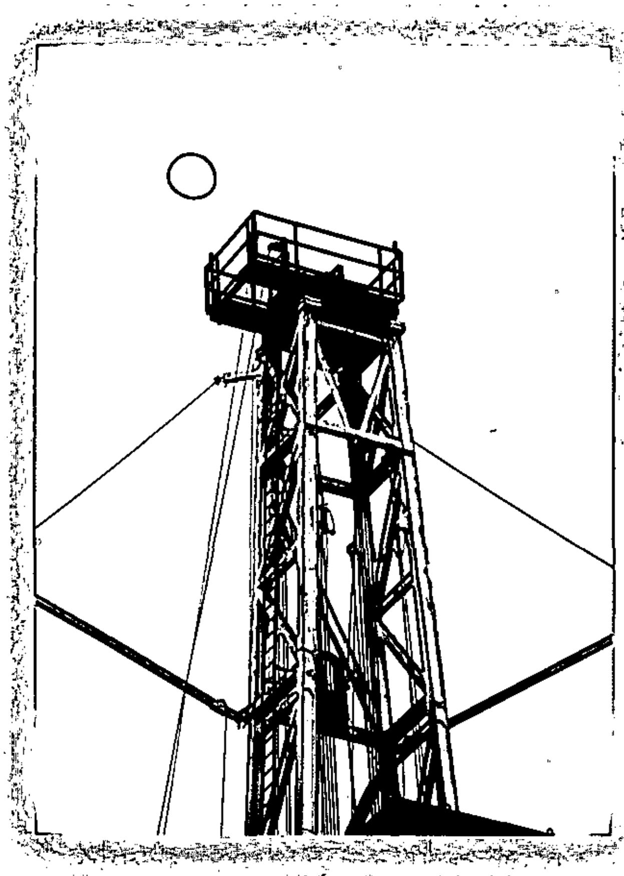
[2] *A Non-GAAP Measure—see page facing back cover*

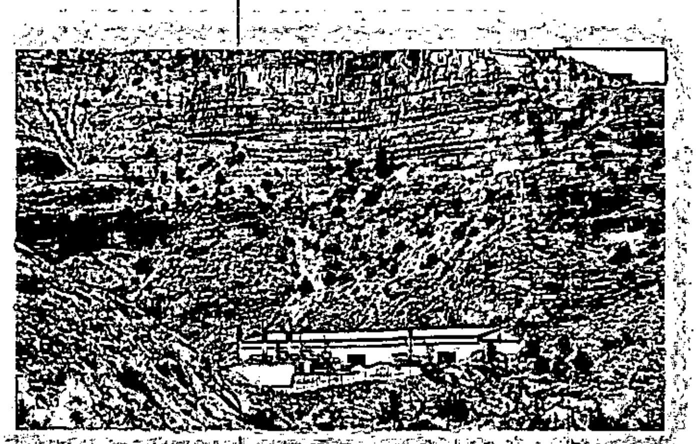
DEVELOPMENT

uinta basin—west tavaputs



West Tavaputs is our preeminent development area in Utah. In 2002, we paid approximately $8 million for this property when we recognized that modern fracture stimulation techniques had not been applied to this area. We have grown gross production from 1 MMcfed to over 85 MMcfed with an ongoing drilling program that targets 2.7 Bcfe EUR wells. We plan a similar shallow drilling program of 30 wells to the Wasatch and Mesaverde formations in 2007 as we had in 2006. We recognize 250 and 300 locations on forty acre spacing and 3P resources totaling nearly 800 Bcfe. Our 83 square mile 3-D seismic survey (acquired in 2004) guides not only our shallow drilling locations, but also reveals significant structures in the Dakota, Entrada, and Navajo formations. We have drilled and completed two successful deep wells (the first was Oil and Gas Investor Magazine's "Best Discovery") and are in the process of completing our third deep well. Good progress continues on our Environmental Impact Statement (EIS) for West Tavaputs. We expect a Record of Decision sometime in late 2007 or early 2008. Once approved, the EIS will allow for full field development with drilling year-round atop the three mesas, thus allowing our per year drilling levels to be increased.



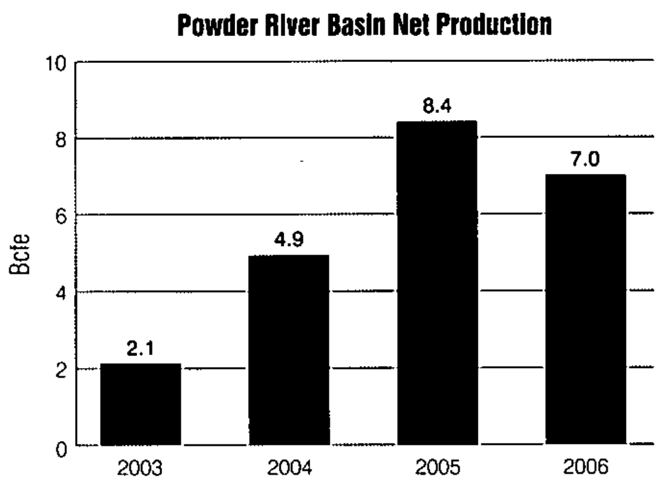


We built our compressor station to aesthetically match the terrain

DEVELOPMENT

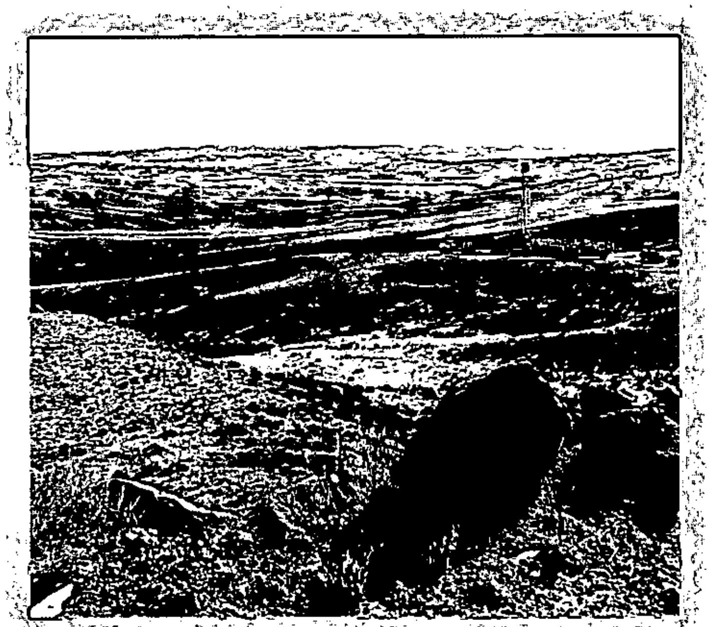
powder river basin—cbm

Scotch compressor station at our Cat Creek area



The Powder River Basin CBM development project is an asset that provides us with lower risk, high return drilling. In 2006, we drilled 99 wells and we added to our Big George program with the acquisition of largely undeveloped properties primarily in the Hartzog Draw and Pumpkin Creek area and now have over 127,000 net acres. We plan to drill between 200 and 250 wells over each of the next several years on our 1,200 location inventory with 3P resources totaling nearly 205 Bcf. We had a 17% production decline in 2006 as our Big George development was still dewatering and not offsetting declines from the legacy Wyodak coal production. However, given the time it takes to dewater the various coals, we believe production will begin ramping up toward the end of 2007, with material production growth expected in 2008 and 2009. The Powder River CBM play provides us with our best incremental drilling costs.

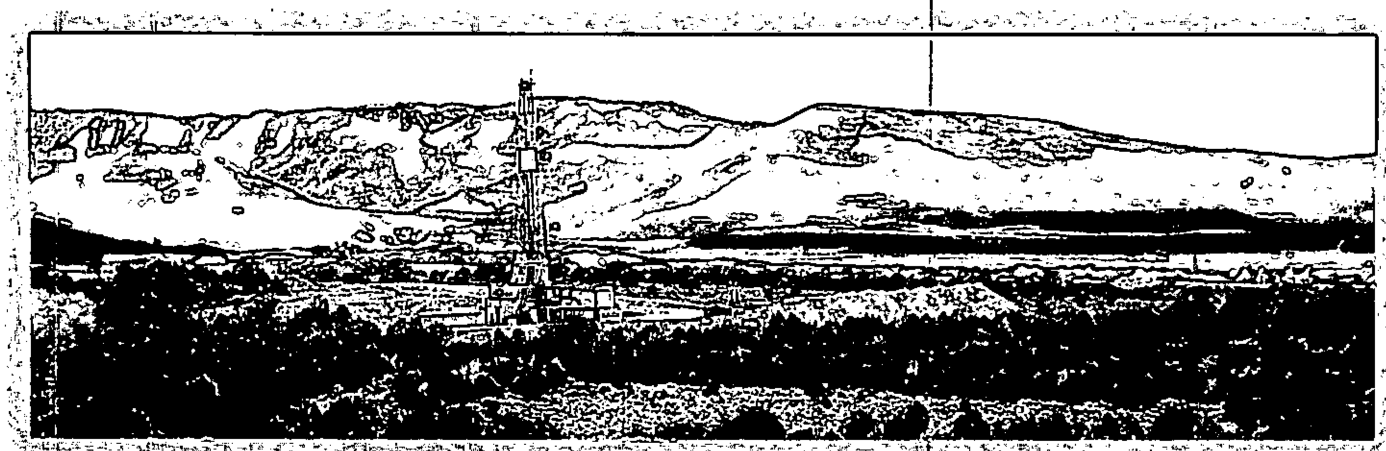
Burrowing owl family—We are alert to protecting the environment in each area we work Photo by: Dan Fillipi. O&G Environmental



Drilling operations conform to natural terrain

DEVELOPMENT

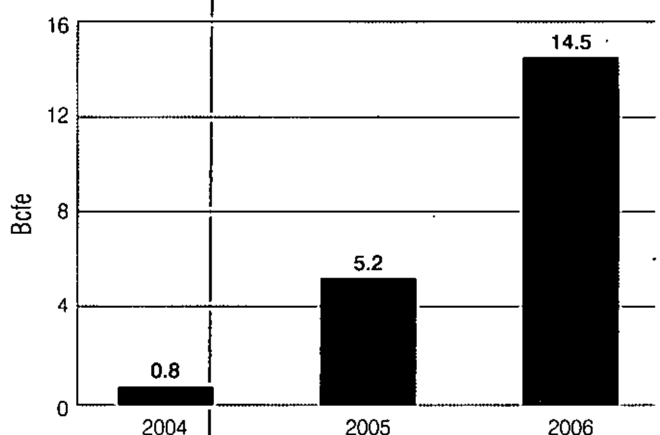
piceance basin

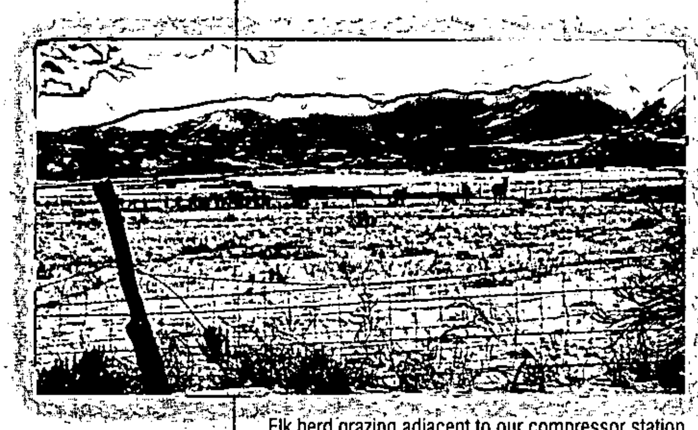


Piceance drilling rig—south of Silt, Colorado in Garfield County

The Piceance Basin is a prime example of the type of development project we like to have in our portfolio. This is a legacy area for our management team. It provides repeatable drilling inventory in an area with significant known gas in place (80 Bcfe per square mile), and it gives us operational scale. Using our technical knowledge base and experience in the Piceance, we can leverage technology and efficiencies to improve economics. We grew daily production nearly eightfold in the two years since we acquired our properties in 2004. We improved our average EUR per well to over 1.2 Bcfe with enhanced fracture stimulation techniques. We have nearly 700 Bcfe of 3P resources in the area and see continued double-digit production and reserve growth in the coming years as we operate a continuous, year round three-rig program. In 2007, we will be actively drilling multiple 10-acre pilots. Much of the Piceance Basin is productive on 10-acre spacing throughout the valley and our management team has extensive experience with infill drilling. We believe 10-acre drilling will allow us to increase the recovery of the significant gas in place.

Piceance Net Production

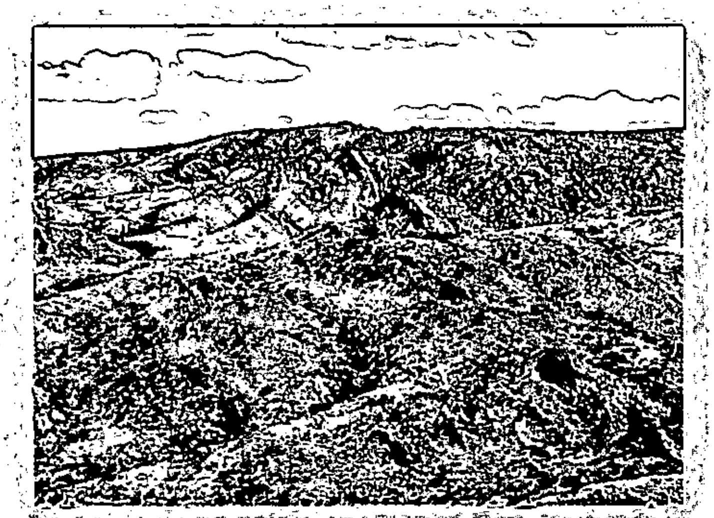




Elk herd grazing adjacent to our compressor station

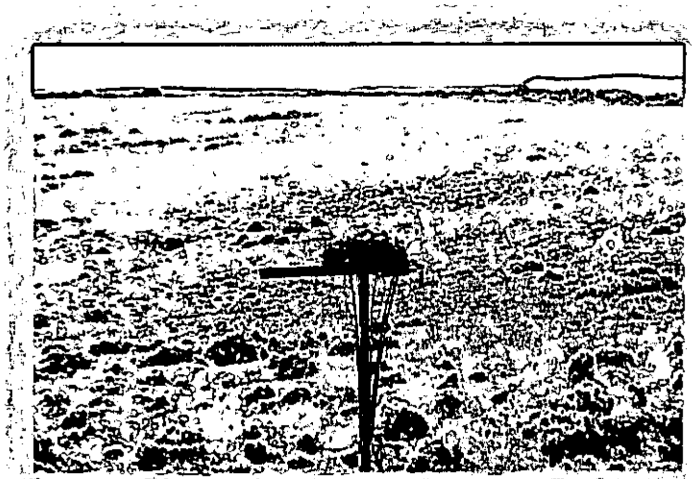
EXPLORATION

wind river basin

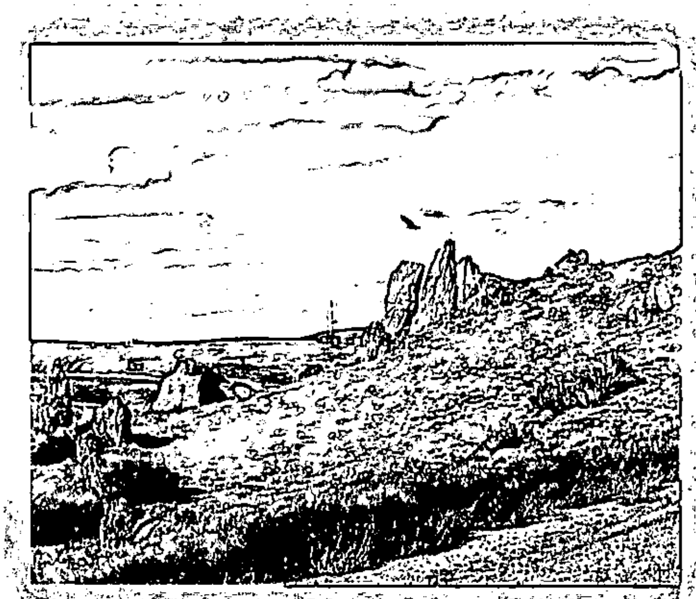


Storage tanks blend in with natural environment

The dynamics of the Wind River Basin have changed in the Company's five year history. During the first few years, we were focused on the prolific shallower Lance-Ft. Union development program along the Waltman Arch. Recent exploratory success has focused our attention on deeper drilling targets in the Frontier, Muddy, and Lakota formations. We have been successful with two deep wells and one re-completion where we have achieved initial production rates as high as 20 MMcfe/d. These high flow rates provide both a strong rate of return and rapid payback. Given the high expense of these deep wells, we plan to bring in a partner to mitigate cost, increase efficiency, and accelerate our exposure to reserves and production with a continuous one-rig program that will allow us to drill up to three wells per year. We are assessing the potential of other plays along the Waltman Arch, including a recent shale gas test in the Cody/Niobrara zones and a CBM pilot in the Meeteetse coals.

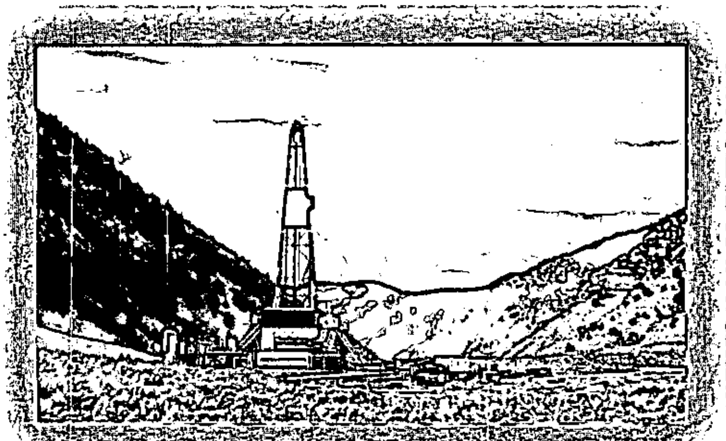


Raptors use artificial nests built by BBC; this promotes safety and provides nesting habitats



Raptor flying over Cave Gulch operations

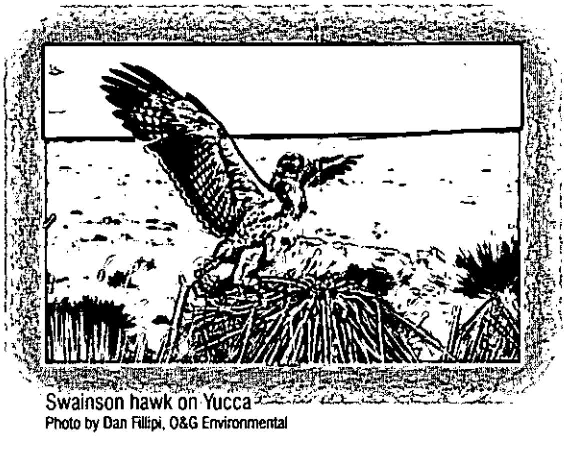
uinta basin–lake canyon



Lake Canyon Deep DLB #15-56 drilling

Lake Canyon is an expansive, multi-township, fractured oil and associated gas prospect in the Uinta Basin where we are currently targeting the Wasatch and Green River formations. We control over 400 square miles, much of it on tribal lands. We were successful in our first Wasatch exploratory well in 2006 and are in the process of completing two recently drilled offsets to this well. The Wasatch is a thick oil prone section that is below 6,000 feet depth. We also participate in the shallower Green River oil play, where our partner was also successful in the drilling of four additional Green River wells in 2006. In December 2006, we added to our position when we signed an Exploration and Development Agreement (EDA) with the Ute Tribe at Blacktail Ridge, a known productive area, where we intend to target the Wasatch and Green River formations. We intend to drill 24 wells delineating this area and our Lake Canyon play in 2007. Numerous wells will need to be drilled to understand the scope and economics of these plays, but we are encouraged with the potential of this immense area.

hook/woodside

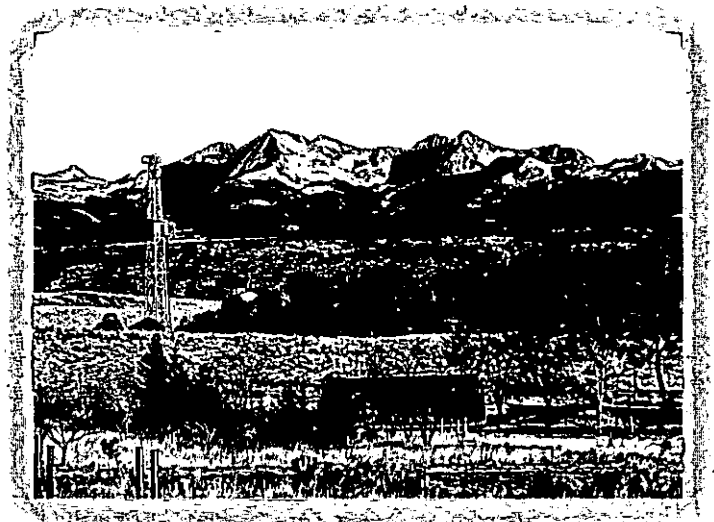


Swainson hawk on Yucca
Photo by Dan Fillipi, O&G Environmental

On the border of the Uinta and Paradox basins sits our Hook/Woodside prospect area where we have over 186,000 net undeveloped acres. At Hook, we will be testing several shale gas intervals (one that is age equivalent to the Barnett Shale of northeast Texas), when we drill three exploratory test wells this summer. At Woodside, we will drill a seismically defined structural Pennsylvanian test in spring 2007.

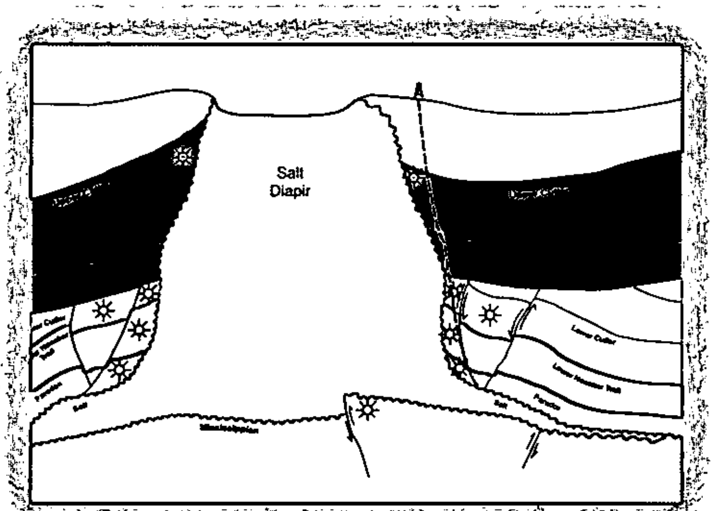
paradox basin—yellow jacket

Our Yellow Jacket prospect is an exploratory resource play where we are targeting the Gothic shale at depths of 6,500 feet. This is a shale gas play that has many of the same attributes as the prolific Barnett shale in East Texas. We drilled and cored two exploratory tests in the fourth quarter of 2006. Having conducted extensive core analysis on both wells, we expect to have completed both wells and have results as we move into the summer months of 2007. We plan two further exploratory test wells in 2007.



Koskie #1 drilling

pine ridge



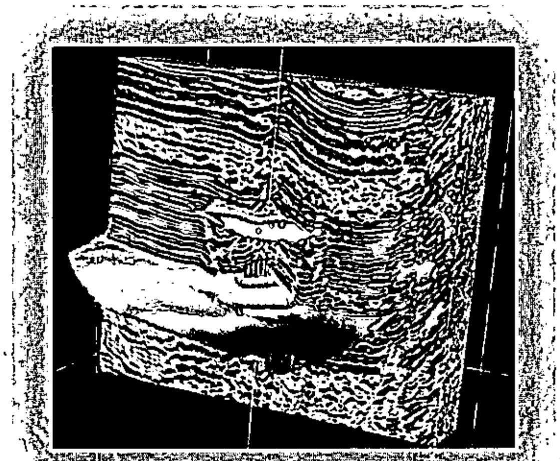
We have over 20,000 net undeveloped acres in our conventional Salt Flank project in the Paradox Basin. With 3-D seismic technology, we are targeting structural features where gas is trapped along the flanks of massive salt intrusions, also known as "salt diapirs". In 2006, we acquired a 20 square mile 3-D seismic survey at our Pine Ridge prospect and plan to drill our first exploration test well in late 2007 or early 2008.

montana overthrust–circus

Our Montana Overthrust prospect is a classic structural play that adds balance and diversity to our portfolio. After conducting a regional geologic study utilizing surface geology, 2-D seismic, and existing well data, we began to assemble a large acreage position (in excess of 300,000 acres) in an area where several major oil companies drilled and encountered live oil and gas shows back in the 1970s and 1980s. All of the historical drilling activity was done prior to the advent of modern day 3-D seismic technology. In 2006 and 2007, we acquired 155 square miles of 3-D seismic to define this complicated geologic structure. We also brought in a joint exploration partner and recouped all of our upfront investment, while retaining a 50% working interest and operations. We have imaged several four-way closures with 3-D seismic data and plan to drill two exploratory test wells in the summer of 2007 and acquire additional 3-D seismic.

Moderate terrain in Circus area

big horn basin



Astroblem—3-D seismic revealing the evidence of a possible meteor impact

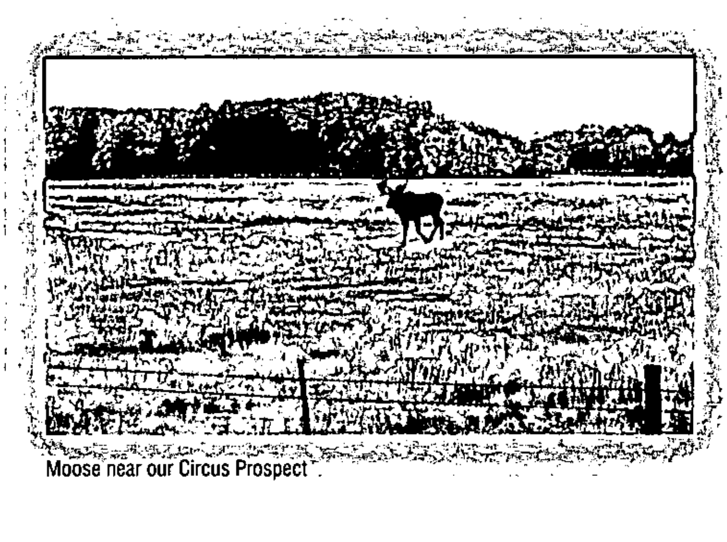
In our Big Horn Basin prospect, we are targeting unconventional tight gas sands in the central portion of the basin where little exploratory drilling has occurred. To date, most drilling in the basin was focused on the shallower oil fields rimming the basin. We operate a 50% working interest and have nearly 83,000 net undeveloped acres. In early 2007, we began recompleting the Sellers Draw #1 well in five different Mesaverde stages and plan to drill one exploratory test well in summer 2007 based on the results of our 3-D seismic survey. We also identified the presence of an unusual feature deep in the section, which appears to be an ancient meteor impact. These features, though fairly rare, when found in hydrocarbon bearing basins are commonly productive.

environmental

Our Rockies growth strategy means the Company conducts much of its business on public lands. While these lands are thought to contain nearly three-fourths of all undiscovered natural gas in the Continental United States, they are also home to wildlife, support grazing, and are used extensively for many forms of recreation.


Sunrise in the Big Horn Basin area

Our policy is to protect these other resource values while pursuing the Company's growth strategy. In order for land managers to protect "the health, diversity and productivity of the public lands for the use and enjoyment of present and future generations," the government applies various tools for planning and controlling resources such as water, wildlife, air, visual and noise considerations, mineral, cultural and other natural resources, and traffic, all leading to the eventual remediation of a well pad. This is the analysis we undertake when conducting an Environmental Impact Statement (EIS), or the less exhaustive Environmental Assessment (EA), both regulatory tools of the National Environmental Policy Act (NEPA). So rigorous is this federal policy that the BLM estimates that just slightly over 10% of the onshore gas reserves on federal lands are accessible under standard lease terms.


Moose near our Circus Prospect

We support these efforts and currently are involved in an EIS at West Tavaputs, which will assess environmental, social, cultural, and economic impacts for all stakeholder activities, not just oil and gas operations. A draft will be released to the public for comment before the BLM issues a Record of Decision. We work with communities and other stakeholders to ensure the EIS addresses all pertinent information. The EIS process is deliberate and usually takes over two years to complete. Once completed, the EIS provides a framework for how a company can operate on federal lands.

One of our competitive advantages is our strategic objective to have the technical expertise for managing NEPA processes, which adds another layer of regulatory oversight to dozens of other federal, state and local laws and regulations. We have also been recognized for efforts ranging from wildlife re-introduction, innovative drilling and operating procedures, and corporate philanthropy.

Ultimately, Company efforts help assure the country remains essentially self reliant for its natural gas needs while complying with some of the most stringent environmental protections in the world.

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

FORM 10-K

(Mark one)

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

or

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

Commission File No. 001-32367

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

Delaware **(State or other jurisdiction of incorporation or organization)**	**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 if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. ☒ Yes ☐ No

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

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

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

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

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). ☐ Yes ☒ 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 the last business day of the registrant's most recently completed second fiscal quarter. $967,118,350

* Without assuming that any of the issuer's directors or executive officers, or the entity affiliated with a director that currently beneficially owns 10,081,278 shares of common stock 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 February 23, 2007, the registrant had 44,269,159 outstanding shares of $.001 par value common stock.

DOCUMENTS INCORPORATED BY REFERENCE:

The information required in Part III of this Annual Report on Form 10-K is incorporated by reference from the registrant's definitive proxy statement to be filed pursuant to Regulation 14A for the registrant's Annual Meeting of Stockholders to be held in May 2007.

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 other costs;
- availability and costs of drilling rigs and field services;
- 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 1A. Risk Factors", "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations", 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", "could", "should", "expect", "plan", "project", "intend", "anticipate", "believe", "estimate", "predict", "potential", "pursue", "target", "seek", "objective", 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 "Item 1A. Risk Factors" 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 and a regional overthrust belt in the Rocky Mountains. 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 internally generated projects.

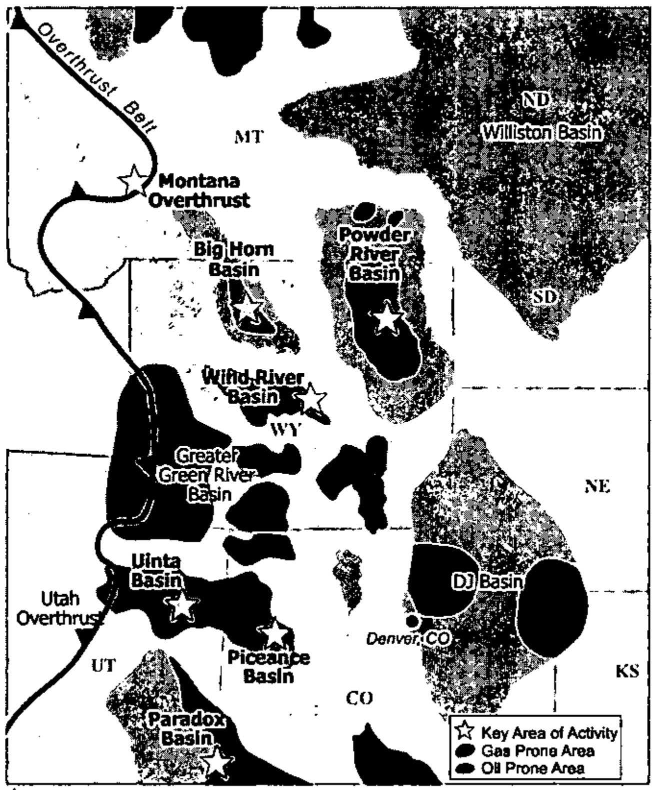
We began active natural gas and oil operations in March 2002 with the acquisition of properties in the Wind River Basin. We acquired these properties from a subsidiary of the Williams Companies, which acquired these properties in connection with the Williams Companies' acquisition of Barrett Resources Corporation in August 2001. Since inception, we substantially increased our activity level and the number of properties that we operate by acquiring a large inventory of undeveloped leasehold interests through federal and state sales as well as private purchases and trades. We have also acquired producing properties that had large undeveloped acreage positions associated with them. For example, 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 interests in properties in the Piceance Basin in or around the Gibson Gulch field; and in May 2006, we added to our coalbed methane position in the Powder River Basin with our acquisition of CH4 Energy Corporation. Our operating results reflect our exploration success and development growth on our properties.

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. See "Financial Statements" and the notes to our consolidated financial statements for financial information about this industry segment.

The following table provides information regarding our operations by basin.

	At December 31, 2006			
Basin	Estimated Net Proved Reserves (1)	Net Producing Wells	Net Undeveloped Acreage	December 2006 Average Daily Net Production
	(Bcfe)			(MMcfe/d)
Uinta	151.3	66.2	181,191 (2)	54.4
Piceance	145.6	214.4	13,637	47.7
Wind River	62.8	153.1	218,699	25.1
Powder River	27.0	359.1	104,479	16.5
Big Horn	—	1.0	82,834	0.1
Paradox	—	—	85,241	—
Green River	—	—	52,097	—
Denver-Julesburg (3)	—	3.0	212,285	—
Williston (3)	41.7	41.2	161,662	7.2
Montana Overthrust	—	—	138,292	—
Utah Hingeline	—	—	18,096	—
Total	428.4	838.0	1,268,513 (2)	151.0

(1) Our proved reserves were determined using the market prices for natural gas and oil at December 31, 2006, which were $4.46 per MMBtu of natural gas and $61.06 per barrel of oil, without 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 "—Oil and Gas Data—Proved Reserves".
(2) An additional 156,060 net undeveloped acres that are subject to drill-to-earn agreements are not included.
(3) We currently are marketing our Williston Basin and Denver-Julesburg Basin properties for sale.



We operate in nine basins and a regional overthrust belt in the Rocky Mountain region of the United States. The basins consist of the Piceance, the Wind River, the Uinta, the Powder River, the Williston, the Green River, the Denver-Julesburg, the Paradox and the Big Horn. We are in the process of marketing our Williston Basin and Denver-Julesburg Basin properties for sale.

Uinta Basin. The Uinta Basin, located in northeastern Utah, was our largest producing area for the year ended December 31, 2006. Our development operations are conducted primarily in West Tavaputs, and we currently are testing offsets to our Lake Canyon discoveries. We also have a position in two exploratory projects in the basin. Key statistics for our position in this basin include:

- 54.4 MMcfe/d of average net production for December 2006, compared to 40.3 MMcfe/d for December 2005
- 151.3 Bcfe of estimated net proved reserves at December 31, 2006
- 66.2 net producing wells at December 31, 2006
- 191,966 total net acres, including 181,191 net undeveloped acres, at December 31, 2006
- an additional 156,060 net undeveloped acres that are subject to drill-to-earn agreements
- 235 square miles of licensed and proprietary 3-D seismic data

- $120.0 million of capital expenditures spent during 2006, which included participating in the drilling of 36 wells and one recompletion
- $165-$180 million estimated total capital expenditures in 2007, including a 65 gross well drilling program

Piceance Basin. The Piceance Basin, located in northwestern Colorado, is a key area for our development activities and expected production growth in 2007. Key statistics for our position in this basin include:

- 47.7 MMcfe/d of average net production for December 2006, compared to 26.5 MMcfe/d for December 2005
- 145.6 Bcfe of estimated net proved reserves at December 31, 2006
- 214.4 net producing wells at December 31, 2006
- 16,447 total net acres, including 13,637 net undeveloped acres, at December 31, 2006
- 20 square miles of proprietary 3-D seismic data
- $138.2 million of capital expenditures spent during 2006, which included participating in the drilling of 68 wells
- $170-$175 million estimated net capital expenditures in 2007, including an 96 gross well drilling program

Wind River Basin. The Wind River Basin is located in central Wyoming. Our operations in the basin include field expansion programs, recompletions as well as exploration projects. Key statistics for our position in this basin include:

- 25.1 MMcfe/d of average net production for December 2006, compared to 45.6 MMcfe/d for December 2005
- 62.8 Bcfe of estimated net proved reserves at December 31, 2006
- 153.1 net producing wells at December 31, 2006
- 223,941 total net acres, including 218,699 net undeveloped acres at December 31, 2006
- 718 square miles of licensed and proprietary 3-D seismic data
- $35.3 million of capital expenditures spent during 2006, which included participating in the drilling of two wells and two recompletions
- $28-$33 million estimated net capital expenditures in 2007, including a six gross well drilling program and three recompletions

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. Key statistics for our position in this basin include:

- 16.0 MMcfe/d of average net production for December 2006, compared to 19.9 MMcfe/d for December 2005
- 27.0 Bcfe of estimated net proved reserves at December 31, 2006
- 359.1 net producing wells at December 31, 2006
- 127,007 total net acres, including 88,129 net undeveloped acres, at December 31, 2006

- $148.0 million of capital expenditures spent during 2006, which included participating in the drilling of 99 wells, the CH4 acquisition and related taxes, and the estimated value of properties acquired for other than cash
- $25-$30 million estimated total capital expenditures in 2007, including a 229 gross well drilling program

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. Key statistics for our position in this basin include:

- 82,834 net undeveloped acres at December 31, 2006
- 203 square miles of licensed and proprietary 3-D seismic data
- Capital expenditures of $2.7 million in 2006 included leasehold acquisitions and 3-D seismic surveys
- Activities in 2007 are planned to include one recompletion, drilling one exploration well and acquiring additional 3-D seismic

Montana Overthrust Belt. The overthrust belt is a broad linear structural feature that runs from southern Utah through the Canadian Rockies. We acquired leasehold interests in an exploration project in Montana along this feature and have acquired 155 square miles of 3-D seismic. Key statistics for our position in this area include:

- 138,292 net undeveloped acres at December 31, 2006 (50% working interest) operated
- 155 square miles of proprietary 3-D seismic data
- Capital expenditures of $5.5 million in 2006 included leasehold acreage acquisitions and 3-D seismic surveys
- Activities in 2007 are planned to include two exploration wells and additional 3-D seismic

Paradox Basin. The Paradox Basin is located in southwestern Colorado and southeastern Utah. We are testing a shale gas concept and plan to test a structure play along the flanks of large salt diapirs. Key statistics for our position in this basin include:

- 85,241 net undeveloped acres at December 31, 2006
- 44 square miles of licensed and proprietary 3-D seismic data
- Capital expenditures of $12.4 million in 2006, which included participating in the drilling of two exploration wells, 3-D seismic survey, and leasehold
- Capital expenditures in 2007 are planned to include a three well exploration program

Williston Basin. The Williston Basin is located in western North Dakota, northwestern South Dakota and eastern Montana. It is a predominantly oil-prone basin. Our activities in this basin have included both development and exploration drilling programs concentrated in three areas. We plan to sell our interests in the Williston Basin in order to focus on other areas. Key statistics for our position in this basin include:

- 7.2 MMcfe/d of average net production for December 2006, compared to 7.2 MMcfe/d for December 2005
- 41.7 Bcfe of estimated net proved reserves at December 31, 2006
- 41.2 net producing wells at December 31, 2006
- 172,761 total net acres, including 161,662 net undeveloped acres, at December 31, 2006
- $31.4 million of net capital expenditures spent during 2006, which included participating in the drilling of 13 wells

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 plays. We currently plan to sell our interests in this basin.

Summary of Development Areas

The following table summarizes the information regarding our key producing areas:

Area	Basin	Average Working Interest (1)	2007 Drilling Locations (2)	2007 Area Budget (3)
				(in millions)
West Tavaputs	Uinta	92.2	29	$125-130
Gibson Gulch	Piceance	79.3	96	170-175
Cave Gulch/Bullfrog	Wind River	89.0	3	20-25
Cooper Reservoir	Wind River	97.3	1	4-7
Talon	Wind River	62.8	2	2-4
Wallace Creek/Stone Cabin	Wind River	98.0	1	1-3
Powder River	Powder River	71.3	229	25-30
Lake Canyon/Blacktail Ridge	Uinta	38.1	33	35-40
Williston	Williston	30 (4)	—	—
Total		64.2	394	$382-414

(1) Average working interest is based on our working interests in producing wells as of December 31, 2006.

(2) For each development area, 2007 drilling locations represent total gross locations specifically identified and scheduled by management as of December 31, 2006 as an estimate of our 2007 drilling activities on existing acreage. Of the 2007 drilling locations, 140 are classified as proved undeveloped reserves, or PUDs. Our actual drilling activities may change depending on the availability of capital, regulatory approvals, seasonal conditions, natural gas and oil prices, rig and services availability, costs, drilling results and other factors. For a more complete description of our proposed activities, see the basin descriptions below.

(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.

(4) We operated 85% of our December 2006 production in the Williston Basin, with an average working interest of 87.5% per operated well. Our average working interest in wells operated by others is 8.5%.

Summary of Exploration Activities

The following table summarizes certain of our exploration activities that are discussed in more detail below.

Exploration Project	Basin	Project Net Acreage (1)	Average Working Interest (2)	2007 Planned Exploratory Activities (3)
Cave Gulch/Waltman (4)(5)	Wind River	15,861	83%	Drill two deep wells
Cooper Reservoir (4)	Wind River	12,262	85%	Drill one deep well
East Madden	Wind River	15,486	86%	Assess drilled well
Stone Cabin (4)	Wind River	10,216	59%	Assessing deep potential
Talon (5)	Wind River	73,440	38%	Complete one well; assess drilled wells
Wallace Creek (4)(5)	Wind River	24,974	71%	Drill one CBM well
Lake Canyon/Brundage Canyon (6)	Uinta	155,414 (6)	69%	Drill 24 wells
Blacktail Ridge (4)(7)	Uinta	25,714	50%	Drill eight wells
West Tavaputs Deep (4)	Uinta	41,038	88%	Drill two wells
Hook (5)	Uinta	92,068	94%	Drill three wells
Woodside (5)	Uinta	26,251	100%	Drill one well
Sandwash	Green River	44,385	100%	Acreage acquisitions
Salt Flank (5)	Paradox	20,238	99%	Acreage acquisitions; drill one well
Yellow Jacket	Paradox	62,563	48%	Acreage acquisitions; drill two wells
Big Horn	Big Horn	83,208	39%	3-D seismic; acreage acquisitions; recomplete one well; drill one well
Montana Overthrust	Overthrust Belt	138,292	44%	3-D seismic; drill two wells
Hingeline	Overthrust Belt	18,096	100%	Assessing future of play
Williston	Williston	172,761	60%	Marketing interest
Tri-State	DJ	213,232	47%	Marketing interest

(1) Project net acreage is the amount of our net leasehold acreage at December 31, 2006 that we have associated with each of our exploration projects.

(2) Average working interest is based on leasehold acreage at December 31, 2006. Also, the working interest numbers are subject to the sale of working interests to industry partners in connection with our joint exploration strategy.

(3) Of the exploration activities planned for 2007 that are included in this table, some already have 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 more detailed description of proposed activities, see the description of each project in the basin sections below.

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

(5) Portions of the exploration program currently are not included in our 2007 capital expenditure budget as 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) Includes an additional 130,346 net undeveloped acres that are subject to drill-to-earn agreements.

(7) Consists of 25,714 net undeveloped acres that are subject to a drill-to-earn agreement.

With respect to certain of our exploration projects, we seek industry partners to enter into joint exploration agreements, which involve the sale of portions of our interests in these projects. The primary objective of this strategy is to accelerate the testing of our exploration project inventory, and mitigate the capital risk of high impact exploration projects, while recouping a portion of our initial investment. We have executed these joint exploration agreements with partners in our East Madden, Yellow Jacket, Circus, Big Horn, Grand River, Red Bank Extension, Red Water, Tri-State, and Cooper Deep exploration projects. We expect to pursue additional joint exploration projects at Hook, Woodside, Salt Flank, other Wind River areas and several other exploration areas. In connection with these anticipated joint exploration agreements, we expect to sell approximately 30% to 60% of our working interests and have our partner fund a significant portion of our share of early drilling costs, depending on the project.

Our Offices

Our company was founded in 2002 and is incorporated in Delaware. Our principal executive offices are located at 1099 18th Street, Suite 2300, Denver, Colorado 80202, and our telephone number at that address is (303) 293-9100.

Our Strategy

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

- ***Drive Growth Through Internally Generated Projects.*** 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, 2006, we participated in the drilling of 1,021 gross wells. We plan to participate in the drilling of a total of 406 gross wells in 2007.
- ***Pursue High Potential Projects.*** We have assembled several projects that we believe provide future long-term drilling inventories. In addition to our development areas, we are involved in multiple exploration projects. Our team of 18 geologists and geophysicists is dedicated to generating new geologic concepts. Our long-term objective is to allocate between 70% and 90% of our capital budget to development projects, with the balance allocated to higher risk, higher potential exploration projects. We may also seek partners to enter into joint exploration agreements in order to mitigate our capital risk and accelerate our exposure to potential reserves and production in these high potential 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 regions in North America with significant remaining growth potential. All of our production is from the Rockies, and for 2006 approximately 92% was natural gas. We expect that as future pipeline capacity is built over the next few years, we will have additional markets for our 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 percentage operatorship of our reserves and production, and our continuing cost management initiatives and technology application. As we manage our growth, we are actively focusing on managing lease operating and gathering expenses, general and administrative costs, and depreciation, depletion and amortization. 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 95% of our December 2006 production and, as of December 31, 2006, we owned an average working interest of approximately 64.2% in our December 2006 production.
- ***Pursue Reserve and Leasehold Acquisitions.*** Past acquisitions have played an important role 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 such as our May 2006 acquisition of

properties in the Powder River Basin in the area of our activities in that basin. 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.

- ***Proven Track Record of Production and Reserve Growth.*** We have increased production and reserves by double-digit percentage growth rates each year that we have been in existence. In 2002, we produced 6.6 Bcfe and, in 2006, we produced 52.1 Bcfe. Proved reserves grew from 119 Bcfe at year-end 2002 to 428 Bcfe at year-end 2006.
- ***Experienced Management Team.*** We believe our management team's experience and expertise in the Rocky Mountains provide a distinct competitive advantage. Our 11 corporate officers average 20 years of experience working in the industry. Our Chief Executive Officer, Chief Operating Officer and most 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.
- ***Inventory of Growth Opportunities.*** We have established an asset base of 1,268,513 net undeveloped leasehold acres as of December 31, 2006, as well as an additional 156,060 net undeveloped acres that are subject to drill-to-earn agreements, and we have multiple exploration projects. We had 3,566 identified drilling locations as of December 31, 2006, including our drill-to-earn acreage. From inception through December 31, 2006, we participated in the drilling of 1,021 gross wells. In 2007, we plan to participate in the drilling of 406 gross wells across our operations.
- ***Expertise with Unconventional Resources.*** Approximately 70% of our properties are classified as unconventional resources, including shale gas plays, coalbed methane, basin-centered tight gas, fractured oil, and biogenic gas. In February 2006, the DOE estimated that production from unconventional resources in the lower 48 states would increase by 27% from 2004 through 2030, whereas production in the lower 48 states from condensate, conventional and offshore would decline during that same period.
- ***Financial Flexibility.*** As of December 31, 2006, we had $41.3 million in cash. At December 31, 2006, the outstanding balance under our $400.0 million credit facility was $188.0 million. We are committed to maintaining a conservative financial position to preserve our financial flexibility. We have hedged approximately 65% of our 2007 estimated production at levels that we expect to give us attractive rates of return. We believe that our operating cash flow, planned asset sales, and available borrowing capacity under our credit facility provide us with the financial flexibility to pursue our currently planned exploration and development activities and leasehold acquisitions.
- ***Significant Employee Investment.*** All of our corporate officers and substantially all our 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.

Areas of Operation

Uinta Basin

Our development and exploration activities in the Uinta Basin began in April 2002 and are focused on various geologic play types in several locations in the basin. During the year ended December 31, 2006, we had capital expenditures of $120.0 million, which included participating in the drilling of 36 wells, of which 31 were completed as of year end and of which two were completed as of February 9, 2007. We operated 61 gross wells in this basin as of December 31, 2006. In our current capital budget, we estimate our capital expenditures in 2007 will be $165 to $180 million in the Uinta Basin area to fund our interests in 65 additional gross wells and infrastructure improvements.

West Tavaputs

We serve as operator of our interests in the West Tavaputs area. Primary targets at West Tavaputs include gas-productive sands of the Wasatch and Mesaverde formations and, with effective application of new fracturing techniques and 3-D seismic, we have increased our ability to commercialize those reservoirs. With the success of our #4-12D well, we have confirmed the discovery of new gas reservoirs in the deeper Dakota, Entrada and Navajo formations in our 2005 Peters Point #6-7D wildcat well.

Our natural gas production at West Tavaputs is gathered and compressed by our facilities and delivered to markets on the Questar pipeline system. We recently entered into precedent agreements with Questar Gas to subscribe for firm transportation arrangements on an expansion project as well as additional processing that we believe will provide adequate capability to move anticipated gas volumes from West Tavaputs. We also are negotiating precedent agreements with Questar Gas to subscribe for processing services to ensure our gas will meet hydrocarbon dewpoint specifications on the Questar southern system.

Full development of the West Tavaputs area will require the completion of an environmental impact statement, or EIS, which we initiated in February 2005 and which we expect to be issued in the fourth quarter of 2007 or first quarter of 2008. See "—Operations—Environmental Matters and Regulation".

Hill Creek

Within the Hill Creek area, we hold interest in 10 wells that targeted the Dakota, Entrada and Wingate formations at depths down to 11,900 feet. No drilling is planned for 2007.

Lake Canyon/Blacktail Ridge/Brundage Canyon

Lake Canyon. Lake Canyon is an exploration project that targets Green River formation oil zones to depths of 5,500 feet and oil zones in the Wasatch to depths of 8,000 feet. In 2006, Wasatch formation oil production was established from the #1 DLB 12-15-56 well. Our 2006 capital program in this area included the drilling of four gross productive Green River formation wells and two additional Wasatch formation wells that currently are being tested.

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 Wasatch formation and deeper horizons, for which we serve as operator, plus up to a 25% interest in shallower Green River 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. The Ute Tribe has an option to participate for a 25% working interest in wells drilled pursuant to the agreement.

Blacktail Ridge. In December, 2006, we entered into an exploration and development agreement with the Ute Tribe and the Ute Development Corporation to explore for and develop oil and natural gas on approximately 51,000 of their net undeveloped acres that are located in Duchesne County, Utah. Pursuant to this agreement, we serve as operator and have the right to earn up to a 50% working interest in all formations. To earn these interests pursuant to this agreement, we are required to drill five Wasatch wells prior to December 31, 2007, and eight Wasatch wells per year thereafter. The Ute Tribe has an option to participate for a 50% working interest in wells drilled pursuant to the agreement.

Brundage Canyon. In September 2004, we entered into a drill-to-earn agreement with the same industry partner as with our Lake Canyon prospect pursuant to which we serve as operator and have the right to earn a

75% working interest in the Wasatch formation and deeper horizons on existing exploration and development agreements that now 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.

Hook and Woodside

We plan to continue to acquire leasehold acreage through 2007 in these prospects in the southwestern portion of the Uinta Basin. We then plan to sell a portion of our interest to an industry partner. Four wells currently are scheduled for this prospect in 2007 to evaluate various geologic concepts.

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 $137.0 million.

Our total leasehold position in the Piceance Basin as of December 31, 2006 consisted of 17,033 gross and 13,637 net undeveloped acres and 3,621 gross and 2,810 net developed acres, all of which are in our Gibson Gulch development area. Our estimated net proved reserves in the Piceance Basin at year end 2006 were 145.6 Bcfe.

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. Although we drill on a 20-acre well pattern, we have received authority for development on a 10-acre pattern. Additionally, we are using recently acquired three-component 3-D seismic to enhance our development program. Our natural gas production in this basin currently is gathered through our own gathering system and delivered to markets through a variety of pipelines including pipelines owned by Questar Pipeline Company, Northwest Pipeline and Colorado Interstate Gas ("CIG").

At December 31, 2006, we held interests in 238 gross (214.4 net) producing wells that produced 47.7 MMcfe/d net to our interest in the month of December 2006 with an average working interest of 79.25%. We serve as operator for 98% of our production in the Piceance Basin based on December 2006 production. In our current capital budget, we estimate our capital expenditures for 2007 will be $170.0-$175.0 million to participate in the drilling of 96 gross wells (79 net wells) in the Gibson Gulch area, including several 10-acre pilots, and to expand our compression and gathering facilities. During the year ended December 31, 2006, we had capital expenditures of $138.2 million, which included participating in the drilling of 68 wells, of which 57 were completed as of year end and of which eight were completed as of February 11, 2007.

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 four general project areas, three of which are located along the greater Waltman Arch area: Cave Gulch, Cooper Reservoir and Wallace Creek. We serve as operator in all these areas. In addition, we have a number of exploration projects, some of which are in areas of the basin where we have no existing development operations. We are seeking industry partners to enter into joint exploration agreements, which would involve the sale of a portion of our interests and joint drilling obligations for certain exploration projects in the Wind River Basin.

Our total leasehold position in the Wind River Basin as of December 31, 2006 consisted of 399,792 gross and 218,699 net undeveloped acres and 6,870 gross and 5,242 developed acres. Our estimated net proved reserves in the Wind River Basin at year end 2006 were 62.8 Bcfe. Our current operations in the basin include field expansion programs, recompletions as well as exploration activities. 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 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 on the overpressured deep Frontier, Muddy and Lakota formations. In addition, we also produce from the shallower Lance and Fort Union formations.

In our current capital budget, we estimate our capital expenditures for 2007 will be \$20.0 to \$25.0 million in Cave Gulch, which includes two deep exploration wells and three recompletions. We plan to bring in an industry partner for the drilling of these deep wells. In the year ended December 31, 2006, we spent \$23.7 million of capital expenditures, which included participating in the drilling of one well, one recompletion, and making facilities improvements to our deep Lakota well.

Cooper Reservoir

Our position in the Cooper Reservoir field lies six miles south of Cave Gulch along the Waltman Arch. The primary producing formations at Cooper are the Lance and Fort Union formations at depths ranging from 3,200 to 8,500 feet. Currently, our primary focus is the deep potential we have identified utilizing 3-D seismic. In 2006, we brought in industry partners on 50% of our interests in the deep horizons and drilled our first deep test well. This deep test, the Cooper Deep #1 well, currently is being tested. We are using 3-D seismic technology across the Cooper Reservoir area to evaluate these and other opportunities.

In our current capital budget, we estimate our capital expenditures for 2007 will be \$4.0 to \$7.0 million in Cooper Reservoir to participate in the drilling of one deep well. During the year ended December 31, 2006, we spent \$6.3 million, which included participating in the drilling of one well.

Wallace Creek

No wells were drilled in Wallace Creek during 2006. The Raderville and Muddy formations are the primary producers in this field and are found at a general depth range of 7,000 and 10,000 feet, respectively. We also recognize a potential coalbed methane play within the multiple coal beds of the Meeteetse formation at depths of 1,500 to 4,500 feet. In 2007, we plan to drill one Meeteetse coalbed test well in order to gather additional reservoir data.

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. In May 2006, we added to our position in the basin with our acquisition of CH4 Energy Corporation. We subsequently sold a portion of CH4's properties. As of December 31, 2006, we held approximately 61,535 gross and 38,878 net developed leasehold acres and 41,697 gross and 88,129 net undeveloped leasehold acres in the Powder River Basin. Our estimated net proved reserves in the basin at year end 2006 were 27.0 Bcfe. In December 2006, we produced a net 16.0 MMcfe/d.

Our key project areas are located in both the Big George and Wyodak fairways. In our current capital budget, we estimate our capital expenditures in the Powder River Basin for 2007 will be \$25 to \$30 million, which includes participating in 229 wells primarily in the Big George Fairway. In the year ended December 31, 2006 we drilled 99 wells. Capital expenditures totaled $148.0 million which included $126.7 million of leasehold acquisition costs primarily related to the acquisition of the CH4 properties. Leasehold acquisition costs include $36.8 million of a non-cash deferred tax liability associated with the difference between the tax basis of the properties acquired in the CH4 acquisition and the book basis attributed to the properties under the purchase method of accounting. As of February 23, 2007, we had the necessary drilling permits and environmental approvals in place for approximately 80% of the Company operated wells that we plan to drill in 2007. 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 desorb 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.

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. See "—Operations—Environmental Matters and Regulation".

Our natural gas production in this basin is gathered through our own gathering systems and, for a majority of our gas, delivered to markets through additional gathering and pipeline systems owned by Fort Union Gas Gathering, LLC and Thunder Creek Gas Services.

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. We had 83,208 net acres in this play at December 31, 2006. Although the Big Horn Basin is largely an oil producing basin, we are pursuing both conventional stratigraphic and structural gas plays and unconventional basin-centered gas plays in the basin. In 2006, we brought in an industry partner and acquired a 42 square mile 3-D seismic survey. In 2007, we plan to re-enter an existing well to test several additional formations, drill one exploration well, and acquire additional 3-D seismic as part of our ongoing program to assess the basin-centered gas potential of the basin. We serve as operator in this project.

Overthrust Belt

Montana Overthrust

We had 138,292 net undeveloped acres in the Montana overthrust belt as of December 31, 2006. In 2005, we acquired approximately 68 square miles of 3-D seismic. In 2006, we brought in an industry partner for cash and properties and acquired additional 3-D seismic. In 2007, we plan to drill two exploration wells and acquire additional 3-D seismic. We have a 50% working interest in this project and serve as operator.

Utah Hingeline

Our Utah Hingeline exploration play is located in the thrust belt of central Utah. As of December 31, 2006, we held interests in 18,096 net undeveloped acres. We have no drilling plans for 2007.

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. As of December 31, 2006, we owned interests in 152,294 gross acres and 85,241 net undeveloped acres and serve as operator in this area.

Salt Flank

The Salt Flank exploration prospect explores for gas fields in stratigraphic and structural traps associated with salt diapirs. We intend to build our acreage position in this play through acquisitions or other arrangements with acreage owners in the area. During 2006, we acquired a 21 square mile 3-D seismic survey at our Pine Ridge prospect. Depending on our evaluation of the 3-D data, we plan to drill an exploration well in late 2007.

Yellow Jacket

This prospect targets natural gas from a fractured shale reservoir at depths of 4,500 to 6,500 feet. In 2006, we continued acreage acquisition, sold a portion of our interest to an industry partner, and drilled two exploratory test wells to evaluate the Gothic shale gas potential. We currently are testing the results of the first two wells and plan to drill with our partner two additional exploration wells in 2007. We have an average 48% working interest in this project.

Williston Basin

The Williston Basin, which is located in western North Dakota, northwestern South Dakota and eastern Montana, is a predominantly oil-producing basin and produces 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 have been concentrated in three of the oil producing formations, the Madison, Bakken and the Red River. We had 138,292 net acres at year-end 2006.

We participated in the drilling of 16 horizontal wells in 2006 as part of our 2006 capital program of $31.4 million in this area. We currently are marketing and plan to sell our interests in the Williston Basin in order to focus on other assets.

Denver-Julesburg Basin

Tri-State

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. Our exploration program targets the biogenic shale gas potential of the 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.

During the year ended December 31, 2006, we participated in the drilling of seven wells, five of which established gas production, made additional leasehold acquisitions, and acquired five 3-D seismic surveys. We are marketing our remaining interests in this area in order to focus on other assets. The Company had 213,232 net acres at year-end 2006.

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, 2004, 2005, and 2006 based on reserve reports prepared by us and reviewed in their entirety by outside independent petroleum engineers. While we are not required by SEC or accounting regulations or pronouncements to have our estimates reviewed, we are required by our revolving credit agreement with our lenders to have an independent engineering firm perform a review on our estimated reserves. 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 outside independent petroleum engineers. However, in aggregate, the independent petroleum engineer estimates of total net proved reserves are within 10% of our internal estimates. 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 Standardized Measure shown in the table is not intended to represent the current market value of our estimated natural gas and oil reserves.

	As of December 31,		
	2004	2005	2006
Estimated Net Proved Reserves:			
Natural gas (Bcf)	257.8	306.0	377.7
Oil (MMBbls)	5.7	5.8	8.5
Total (Bcfe)	292.3	341.0	428.4
Percent proved developed	61.1%	61.1%	58.1%
Standardized Measure (in millions) (1)	$466.1	$782.5	$529.3

(1) 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. In accordance with Financial Accounting Standards Board requirements, our reserves and the future net revenues were determined using market prices for natural gas and oil at each of December 31, 2004, 2005, and 2006, which were $5.52 per MMBtu of gas and $43.46 per barrel of oil at December 31, 2004, $7.72 per MMBtu of gas and $61.04 per barrel of oil at December 31, 2005, and $4.46 per MMBtu of gas and $61.06 per barrel of oil at December 31, 2006. These prices were adjusted by lease for quality, transportation fees and regional price differences.

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 an estimation of 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 " Item 1A. Risk Factors".

At year-end 2006, we revised our proved reserves upward by 12.4 Bcfe, excluding pricing revisions. This revision was primarily the result of increased performance of wells drilled during the last half of 2005 and the first half of 2006. The pricing revision at year-end 2006 at prices of $4.46 per MMBtu of gas and $61.06 per barrel of oil, relative to year-end 2005 prices of $7.72 per MMBtu and $61.04 per barrel of oil, was downward 33.8 Bcfe. These prices were adjusted by lease for quality, transportation fees and regional price differences.

During years 2004 and 2005, we participated in drilling 610 gross wells. Of the 610 wells, 158 were producing at less than 75% of the original forecast at December 31, 2005. The revision in forecast of these wells resulted in negative reserve revisions, excluding prices effect, of 32 and 24.7 Bcfe for year-end 2004 and 2005, respectively. These revisions resulted from estimating reserves with insufficient performance to define long term production profiles. In order to reduce the risk of negative reserve revisions, we place lower reserve values on new wells in areas of insufficient performance. We will only increase the reserve values after sufficient performance data is acquired.

We use our internal reserve estimates rather than the estimates from the independent engineering firms because we believe that our reserve and operations engineers are more knowledgeable about the wells due to our continual analysis throughout the year as compared to the relatively short term analysis performed by the independent engineers. We use our internal reserve estimates on all properties regardless of the positive or negative variance to the independent engineers. If a variance greater than 10% occurs at the field level, it may suggest that a difference in methodology or evaluation techniques exists between the Company and the independent engineers. These differences are investigated by the Company and the independent engineers and discussed with the independent engineers to confirm that we used the proper methodologies and techniques in estimating reserves for these fields. These differences are not resolved to a specific tolerance at the field or property level.

Our outside 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. The reviews performed by Netherland, Sewell & Associates, Inc. for our Powder River Basin CBM properties and Ryder Scott Company, L.P. for the remainder of our properties, as requested by our company, are the collective application of a series of procedures by each engineer. These review procedures may be the same or different from each other as well as those review procedures performed by independent engineering firms for other oil and gas companies. 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.

In the case of the properties reviewed by each of the two independent engineering firms as of December 31, 2006, in the aggregate, Ryder Scott Company, L.P. was 6.2% below our reserve estimate and Netherland, Sewell & Associates, Inc. was 7.9% below our reserve estimate. For estimates of proved reserves at December 31, 2006, our outside independent reserve engineers arrived at reserve estimates that are greater than 10% above or below our own estimates for approximately 52% of our wells. This represents approximately 45% of the total proved reserves covered in the review reports. At the material property level, the independent engineer reserve estimates range between 21.3% above our internal reserve estimates to 2.4% below our estimates in the year-end 2006 reserve report. At year-end 2005, at the material property level, the independent engineer reserve estimates range between 1.0% above our internal reserve estimates to 0.3% below our estimates. At year-end 2004, at the material property level, the independent engineer reserve estimates range between 0.3% above our internal reserve estimates to 13.8% below our estimates.

The Ryder Scott review process of our wells and reserve estimates is intended to determine the percent difference, in the aggregate, of our internal net proved reserve estimate and the reserve estimate of Ryder Scott. The review process includes the following:

- The Ryder Scott engineer performs an independent decline curve analysis on proved producing wells based on all production data and pressure information available and pertinent. We provide this information to Ryder Scott.
- The Ryder Scott engineer may verify this data with the public data.
- The Ryder Scott engineer uses his or her individual interpretation of the information and knowledge of the reservoir and area to make an independent analysis.
- For the reserve estimate of proved non-producing and proved undeveloped locations, the Ryder Scott engineer and other Ryder Scott technical personnel he or she deems necessary will review our geologic maps, log data, core data, pertinent pressure data, test information and pertinent technical analyses, as well as production data from offsetting producers.
- The Ryder Scott technical staff may prepare independent maps and volumetric analyses or make adjustments they deem appropriate to the maps or volumetric analysis provided for purposes of the reserve review.
- The Ryder Scott engineer will verify any change in well spacing before accepting locations and will review our production logs, volumetric analyses, well tests and any other data pertaining to drainage issues before estimating reserves.

- The Ryder Scott engineer will estimate the hydrocarbon recovery based upon their knowledge and experience.
- The Ryder Scott engineer does not verify our working and net revenue interests or product price deductions.
- The Ryder Scott engineer does not verify our capital costs although they may ask for confirming information.
- The Ryder Scott engineer does not review historic operating cost, revenue or pricing information.
- The Ryder Scott engineer confirms the oil and gas prices used for the SEC reserve estimate.
- Ryder Scott does not estimate the future net revenue of our properties.
- Ryder Scott will confirm that their reserve estimate is within a 10% variance of our internal reserve estimate based on the ownership, capital and operating expenses utilized by us in our evaluation, in the aggregate, before a review letter is issued.
- The review by Ryder Scott is not performed such that differences on a well level are resolved to any specific tolerance.

The reserve review letter provided by Ryder Scott states that the proved reserves (as defined by Rule 4-10(a)(2) of Regulation S-X) are "reasonable in the aggregate" following an analysis using their independent forecasts with economic parameters and other factual data provided by us and accepted by Ryder Scott.

The Netherland, Sewell & Associates, Inc. (NSAI) review process of our wells and reserve estimates for our Powder River Basin CBM properties is intended to determine the percent difference, in the aggregate, of our internal net proved reserve estimate and future net revenue (discounted 10%) and the reserve estimate and net revenue as determined by NSAI. The review process includes the following:

- The NSAI engineer performs an independent decline curve analysis on proved producing wells based on production and pressure data. This data is provided to NSAI by our company as well as other companies operating in the Powder River Basin.
- The NSAI engineer may verify the production data with the public data.
- The NSAI engineer uses his or her individual interpretation of the information and knowledge of the reservoir and area to make an independent analysis of proved producing reserves.
- The NSAI technical staff will prepare independent maps and volumetric analyses on our properties and offsetting properties. They review our geologic maps, log data, core data, pertinent pressure data, test information and pertinent technical analyses, as well as data from offsetting producers.
- For the reserve estimates of proved non-producing and proved undeveloped locations, the NSAI engineer will estimate the potential for depletion by generating a potentiometric surface map which relates directly to remaining gas-in-place and analyzing this information with the maps generated earlier in the process.
- The NSAI engineer will estimate the hydrocarbon recovery of the remaining gas-in-place based upon their knowledge and experience.
- The NSAI engineer does not verify our working and net revenue interests or product price deductions.
- The NSAI engineer does not verify our capital costs although they may ask for confirming information.
- The NSAI engineer reviews 12 months of operating cost, revenue and pricing information that we provide.
- The NSAI engineer confirms the oil and gas prices used for the SEC reserve estimate.
- NSAI will confirm that their reserve estimate is within a 10% variance of our internal net reserve estimate and estimated future net revenue (discounted 10%), in the aggregate, before a review letter is issued.

- The review by NSAI is not performed such that differences in reserves or revenue on a well level are resolved to any specific tolerance.

The reserve review letter provided by NSAI states that "in our opinion the estimates of Bill Barrett's proved reserves and future revenue shown herein are, in the aggregate, reasonable" following an independent estimation of reserve quantities with economic parameters and other factual data provided by us and accepted by NSAI.

Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The Standardized Measure 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 Standards 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 and NSAI 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 nor NSAI 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 2006, we paid Ryder Scott $62,542 for reviewing our reserve estimates and $0 for other consulting services. During 2006, we paid NSAI $66,146 for reviewing our reserve estimates and $0 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:

	Year Ended December 31,		
	2004	2005	2006
Production Data:			
Natural gas (MMcf) (1)	28,864	36,287	47,928
Oil (MBbls)	474	523	696
Combined volumes (MMcfe)	31,708	39,425	52,104
Daily combined volumes (MMcfe/d)	86.6	108.0	142.8
Average Prices (2):			
Natural gas (per Mcf)	$ 5.10	$ 7.16	$ 6.40
Oil (per Bbl)	39.49	46.68	53.50
Combined (per Mcfe)	5.23	7.21	6.60
Average Costs (per Mcfe):			
Lease operating expense	$ 0.46	$ 0.50	$ 0.57
Gathering and transportation expense	0.19	0.30	0.30
Production tax expense	0.63	0.85	0.50
Depreciation, depletion and amortization (3)	2.15	2.27	2.69
General and administrative (4)	0.57	0.62	0.53

(1) Production of natural gas liquids is included in natural gas revenues and production.

(2) Includes the effects of hedging transactions, which reduced average natural gas prices by $0.43 per Mcf in 2004, $0.57 per Mcf in 2005, and increased average natural gas prices by $0.46 per Mcf in 2006.

(3) The depreciation, depletion and amortization per Mcfe for the year ended December 31, 2006 excludes the production associated with our properties held for sale throughout the year in the Uinta, Williston and DJ Basins as these properties were excluded from amortization beginning with the point at which these properties were classified as held for sale.

(4) General and administrative expense presented herein excludes non-cash stock-based compensation of $3.0 million, $3.2 million and $6.5 million for the years ended December 31, 2004, 2005 and 2006, respectively, which equates to $0.10 per Mcfe, $0.08 per Mcfe and $0.12 per Mcfe, respectively. Non-cash stock-based compensation is combined with general and administrative expense for a total of $21.1 million, $27.8 million and $34.2 million for the years ended December 31, 2004, 2005 and 2006, respectively, in the Consolidated Statement of Operations. Management believes the separate presentation of the non-cash component of general and administrative expense is useful because the cash portion provides a better understanding of our required cash for general and administrative expenses. We also believe that this disclosure allows more accurate comparison to our peers, which may have higher or lower costs associated with equity grants.

Productive Wells

The following table sets forth information at December 31, 2006 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	238	214.4	—	—
Wind River (1)	171	153.1	—	—
Uinta	76	65.4	1	0.8
Powder River	505	350.7	43	8.4
Williston (1)	—	—	105	41.2
Big Horn	2	1	—	—
DJ Basin	6	3	—	—
Total	998	787.6	149	50.4

(1) The two 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, 2006 relating to our leasehold acreage.

	Developed Acreage (1)		Undeveloped Acreage (2)	
Basin	Gross (3)	Net (4)	Gross (3)	Net (4)
Piceance	3,621	2,810	17,033	13,637
Wind River	6,870	5,242	399,792	218,699
Uinta	12,064	10,775	218,322	181,191 (5)
Powder River	61,535	38,878	141,697	88,129
Williston (6)	14,904	11,099	275,220	161,662
Green River	—	—	61,443	52,097
Denver-Julesburg (6)	1,894	947	450,250	212,285
Paradox	—	—	152,294	85,241
Big Horn	801	374	213,971	82,834
Montana Overthrust	—	—	311,889	138,292
Utah Hingeline	—	—	26,417	18,096
Other	1,201	884	35,887	16,350
Total	102,890	71,009	2,304,215	1,268,513 (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 156,060 net undeveloped acres that are subject to drill-to-earn agreements are not included.
(6) These properties are held for sale as of December 31, 2006.

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 Environmental Assessment, Environmental Impact Statement or related legal challenge. The following table sets forth as of December 31, 2006 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, 2007	208,511	100,596
December 31, 2008	474,610	217,898
December 31, 2009	202,053	105,162
December 31, 2010	305,268	142,750
December 31, 2011 and later (1)	1,113,773	702,107
Total	2,304,215	1,268,513

(1) Includes 393,255 gross and 183,574 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.

	Year Ended December 31, 2004		Year Ended December 31, 2005		Year Ended December 31, 2006 (1)	
	Gross	Net	Gross	Net	Gross	Net
Development						
Productive	150	147.9	98	82.3	48	41.1
Dry	2	1.7	3	3.0	—	—
Exploratory						
Productive	93	79.9	103	84.9	121	85.2
Dry	13	10.0	5	3.3	3	1.6
Total						
Productive	243	227.8	201	167.2	169	126.3
Dry	15	11.7	8	6.3	3	1.6

(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 reserves have been attributed at the time at which drilling of the wells 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 2006, we completed 156 gross (119.7 net) productive and zero gross (zero net) dry development wells and 13 gross (6.6 net) productive and three gross (1.6 net) dry exploratory wells.

From inception through December 31, 2006, we participated in drilling 1,021 gross wells, of which 705 were completed as producing, 287 were in process of completing or dewatering and 29 were dry holes. Also during that time, we recompleted 95 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 obtain regulatory authorizations, 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 gas purchase contracts with daily, monthly, seasonal, annual or multi-year terms, all at market prices. 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 the 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 fluctuations in gas prices. For a more 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".

Our natural gas and oil are transported through our own and third party gathering systems and pipelines, and 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. 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. In certain instances, we enter into firm transportation agreements to provide for pipeline capacity to flow and sell a portion of our gas volumes. We also may enter into firm sales agreements to ensure that we are selling to a purchaser who has contracted for pipeline capacity. These agreements are subject to the limitations discussed above in this paragraph. The following table sets forth information with respect to long term (greater than one year from December 31, 2006) firm transportation contracts for pipeline capacity, which typically require a demand charge and firm sales contracts.

Type of Arrangement	Pipeline System / Location	Deliveries (MMBtu/d)	Term
Firm Sales	Kinder Morgan Interstate	22,000	11/97 – 12/07
Firm Transport	WIC Medicine Bow	30,000	1/05 – 3/07
Firm Sales	Questar Pipeline	10,000	4/06 – 12/09
Firm Sales	Questar Pipeline	5,000	4/06 – 3/09
Firm Sales	Questar Pipeline	8,500	5/05 – 3/10
Firm Transport	Questar Pipeline	12,000	11/05 – 10/15
Firm Transport	Questar Pipeline	25,000	1/07 – 12/16
Firm Transport	Cheyenne Plains	9,000	2/05 – 4/17
Firm Transport	Questar Pipeline	25,000	11/07 – 10/17
Firm Transport	Questar Pipeline	11,000	4/07 – 9/08
Firm Transport	Cheyenne Plains	5,000	5/17 – 4/18
Firm Transport	Rockies Express	25,000	1/08 – 6/19

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 to 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 the 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 our properties or affect of 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 can 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.

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;
- with respect to operations affecting federal lands or leases, require time consuming environmental analysis; and
- expose us to litigation by environmental and other special interest groups.

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 and consequently affects profitability. Additionally, Congress and federal and state agencies frequently revise the environmental laws and regulations, and any changes that result in delay or 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, 2006, we did not incur any material capital expenditures for remediation or retrofit of 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 environmental assessment, or EA, prepared that assesses the potential direct, indirect and cumulative impacts of a proposed project. If impacts are considered significant, the agency will prepare a more detailed environmental impact study, or 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. Authorizations under NEPA also are subject to protest, appeal or litigation, which can delay or halt 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".

We believe that we are 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 that the current costs of managing our wastes as they are presently classified 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 the 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 will 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 we own or operate, and 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. The Kyoto Protocol to the United Nations Framework Convention on Climate Change went into effect in February 2005 and requires all industrialized nations that ratified the Protocol to reduce or limit greenhouse gas emissions to a specified level by 2012. The United States has not ratified the Protocol, and the U.S. Congress has resisted recent proposed legislation directed at reducing greenhouse gas emissions. However, there is increasing public pressure from environmental groups and some Northeastern and West Coast states for the United States to develop a national program for regulating greenhouse gas emissions, and several states have already adopted regulations or announced initiatives focused on decreasing or stabilizing greenhouse gas emissions associated with industrial activity, primarily carbon dioxide emissions from 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 the combustion of fossil fuels or the venting of natural gas 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 effect, 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 a Native American reservation. Further, lessees and operators within a 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 February 16, 2007, we had 216 full time employees. Of our 216 full time employees, 139 work in our Denver office and 77 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 is represented by labor unions or covered by any collective bargaining agreement. We believe that our relations with our employees are good.

Offices

As of December 31, 2006, we leased approximately 60,533 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 March 2011. We also own field offices in Waltman, Wyoming and Roosevelt, Utah, and lease field offices in Gillette, Wyoming, and Parachute, Colorado. We believe that our facilities are adequate for our current operations and that we can obtain additional leased space 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.

3C 3-D seismic. A three dimensional seismic survey employing three-component geophones. These multi-component geophones record three orthogonal components of ground motion and provide information about shear waves that are unobtainable by conventional 3-D seismic surveys.

3-D seismic. Acoustical reflection 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.

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.

Environmental Impact Statement (EIS). An environmental impact statement, a more detailed study that can be required pursuant to federal law of the potential direct, indirect and cumulative impacts of a project that may be made available for public review and comment.

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.

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

Identified drilling locations. Total gross locations specifically identified and scheduled by management as an estimation of our multi-year drilling activities on existing acreage. Our actual drilling activities may change depending on the availability of capital, regulatory approvals, seasonal restrictions, natural gas and oil prices, costs, drilling results and other factors.

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.

Net revenue interest. An owner's interest in the revenues of a well after deducting proceeds allocated to royalty and overriding interests.

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

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.

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.

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, 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% to reflect timing of future cash flows.

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.

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 1A. Risk Factors

Our 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;
- the price and availability of alternative fuels; and
- variations between product prices at sales points and applicable index prices.

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 or development 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 for various periods since our inception and may 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 assumptions will materially affect the quantities 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 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. At year-end 2004 and 2005, we revised our reserves downward by 32 Bcfe and 24.7 Bcfe, excluding pricing revisions, respectively. We participated in drilling 797 gross wells from inception through December 31, 2005. Of the 797 wells, 219 were producing at less than 75% of original forecast at year-end 2005, which resulted in the reserve revisions in 2004 and 2005.

Our estimates of proved reserves are determined at prices and costs at the date of the estimate. Any significant variance from these prices and costs could greatly affect our estimates of reserves. The pricing revision at year-end 2006 at prices of $4.46 per MMBtu of gas and $61.06 per barrel of oil, relative to year-end 2005 prices of $7.72 per MMBtu and $61.04 per barrel of oil, was downward 33.8 Bcfe.

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. For additional information about these risks and their impact on our reserves, see "Items 1 and 2. Business and Properties—Oil and Gas Data—Proved Reserves" and "Notes to Consolidated Financial Statements—14. Supplementary Oil and Gas Information (unaudited)—Analysis of Changes in Proved Reserves".

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. Because total estimated proved reserves include our proved undeveloped reserves at December 31, 2006, production will decline even if those proved undeveloped reserves are developed and the wells produce as expected. The 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 upon 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, 2006, we participated in drilling a total of 1,021 gross wells, of which 29 have been identified as dry holes. Of the 797 wells drilled from inception through December 31, 2005, 219 were producing at less than 75% of original forecast at year-end 2005. 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 well is often uncertain and new wells may not be productive.

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

The Powder River Basin represents a significant part of our drilling program and production. Our development operations are conducted in seven project areas in this basin. In the Powder River Basin, nearly all of our operations are in coalbed methane plays, and our key project areas are located in areas that have been the most active drilling areas in the Rocky Mountain region. As a result, many of our leases are in areas that may 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, natural gas and oil 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. In 2007, we plan to participate in the drilling of 406 gross wells.

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 geoscientists to know whether hydrocarbons are, in fact, present in those structures. We are employing 3C 3-D seismic technology to certain of its projects. The implementation and practical use of 3C 3-D seismic technology is relatively new, unproven and unconventional, which can lessen its effectiveness, at least in the near term, and increases its cost. 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 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, we will have 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 related lawsuits; and
- adverse weather conditions.

The occurrence of these events also could impact third parties, including persons living near our operations, our employees and employees of our contractors, leading to injuries or death or property damage. As a result, we face the possibility of liabilities from these events that could adversely affect our business, financial condition or results of operations.

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 economically 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 restricts 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. Under these laws and regulations, we could be held liable for personal injuries, property damage (including site clean-up and restoration costs), and other damages. Failure to comply with these laws and regulations may also result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties, including the assessment of natural resource damages. Environmental and other governmental laws and regulations also increase the costs to plan, design, drill, install, operate and abandon oil and natural gas wells. 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, more vigorous enforcement policies of the regulatory agencies, 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.

In August 2004, the Tenth Circuit Court of Appeals in Pennaco Energy, Inc. v. United States Department of the Interior, upheld a decision by the Interior Board of Land Appeals that the Department of the Interior's Bureau of Land Management, or BLM, failed to fully comply with the National Environmental Policy Act, or NEPA, in granting certain federal leases in the Powder River Basin to Pennaco Energy, Inc. for coalbed methane development. Other recent decisions in the federal district court in Montana have also held that BLM failed to comply with NEPA when considering coalbed methane development in the Powder River Basin. While these recent decisions have not had a material direct impact on our current operations or planned exploration and development activities, future litigation and/or agency responses to such litigation could materially impact our ability to obtain required regulatory approvals to conduct operations in the Powder River Basin.

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 that can spread these additional costs over a greater number of wells and larger operating area. See "Items 1 and 2. Business and Properties—Business—Operations—Environmental Matters and Regulation" and "Items 1 and 2. Business and Properties—Business—Operations—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 Uinta Basins. Approximately 34% of our proved reserves at December 31, 2006 and approximately 30% of our December 2006 production were located in the Piceance Basin and approximately 35% of our proved reserves at December 31, 2006 and approximately 35.5% of our December 2006 production were located in the Uinta 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, the availability and capacity of compression and gas processing facilities, 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 on federal lands, drilling and other oil and natural gas activities can only be conducted during limited times of the year. This limits our ability to operate in those areas and can intensify competition during those times 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. For example, we encountered limitations on our activities in the West Tavaputs area of the Uinta Basin earlier than expected in the fourth quarter of 2004 due to lease stipulations, which prevented us from completing wells. In addition, our costs increased due to removal of a drilling rig, incurrence of expenses reinstalling that rig and additional mobilization costs when the winter stipulations ended in the spring of 2005.

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, 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 contractual 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. 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.

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 a portion of our future capital needs. Our current revolving credit facility restricts our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations. We also are, and expect to continue to be, 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.

Our current revolving credit facility limits the amounts we can borrow up 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

Our stock price and trading volume may be volatile, which could result in losses for our stockholders.

The equity trading markets may experience periods of volatility, which could result in highly variable and unpredictable pricing of equity securities. The market price of our common stock could change in ways that may or may not be related to our business, our industry or our operating performance and financial condition. In addition, the trading volume in our common stock may fluctuate and cause significant price variations to occur. Some of the factors that could negatively affect our share price or result in fluctuations in the price or trading volume of our common stock include:

- 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.

Many of these factors are beyond our control, and we cannot predict their potential effects on the price of our common stock. We cannot assure you that the market price of our common stock will not fluctuate or decline significantly in the future. In addition, the stock markets in general can experience considerable price and volume fluctuations.

Future sales of our common stock or other equity linked products 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 February 23, 2007, we had 44,269,159 shares of common stock outstanding, excluding stock options. All of the 14,950,000 shares sold in our initial public offering in December 2004, other than shares purchased by our affiliates, are freely tradable. In addition, the remaining outstanding shares are either freely tradable or may be sold in accordance with the provisions of Rule 144. Certain of our stockholders have contractual rights to cause us to register the resale of up to 14,332,836 of these outstanding shares. This registration may be accomplished quickly by filing prospectus supplements under our currently effective shelf registration statement. The resale of a large number of shares could cause our stock price to decline.

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 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;
- 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 our 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. owns approximately 23% of our outstanding common stock. Accordingly, this stockholder 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. In addition, one of our directors is affiliated with Warburg Pincus Private Equity VIII, L.P.

Furthermore, conflicts of interest could arise in the future between us, on the one hand, and our 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 1B. Unresolved Staff Comments

Not applicable.

Legal Proceedings

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

Not applicable.

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 two most recent fiscal years as reported by the New York Stock Exchange, is as follows:

	High	Low
2005		
First Quarter	$33.00	$26.00
Second Quarter	32.30	25.90
Third Quarter	39.39	28.89
Fourth Quarter	42.59	30.19
2006		
First Quarter	$40.85	$29.00
Second Quarter	37.90	26.00
Third Quarter	31.60	23.35
Fourth Quarter	33.20	22.60

On February 23, 2007, the closing sales price for the common stock as reported by the NYSE was $30.16 per share.

Holders. On February 23, 2007, the number of holders of record of common stock was 291.

Dividends. We have not paid any cash dividends since our inception. Because we anticipate that all earnings will be retained for the development of our business and our credit facility restricts the payment of dividends, no cash dividends will be paid on our common stock in the foreseeable future.

Issuer Purchases of Equity Securities. The following table contains information about our acquisitions of equity securities during the years ended December 31, 2005 and 2006.

Issuer Purchases of Equity Securities

Period	Total Number of Shares (1)	Weighted Average Price Paid Per Share	Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs
December 1 – 31, 2005	124,024	$41.76	—	—
January 1 – 31, 2006	—	—	—	—
February 1 – 28, 2006	—	—	—	—
March 1 – 31, 2006	230	$31.91	—	—
April 1 – 30, 2006	—	—	—	—
May 1 – 31, 2006	63,181	$30.39	—	—
June 1 – 30, 2006	92,664	$31.94	—	—
July 1 – 31, 2006	—	—	—	—
August 1 – 31, 2006	—	—	—	—
September 1 – 30, 2006	186	$24.63	—	—
October 1 – 31, 2006	—	—	—	—
November 1 – 30, 2006	5,475	$30.72	—	—
December 1 – 31, 2006	—	—	—	—
Total	285,760	$35.83	—	—

(1) Represents shares delivered by employees to satisfy the exercise price of stock options and tax withholding obligations in connection the exercise of stock options and shares withheld from employees to satisfy tax withholding obligations in connection with the vesting of equity shares of common stock issued pursuant to the Company's employee incentive plans.

Equity Compensation Plan Information

The following table provides aggregate information presented as of December 31, 2006 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	2,683,593	$26.31 (1)	2,884,136
Equity compensation plans not approved by shareholders	—	—	—
Total	2,683,593	$26.31	2,884,136

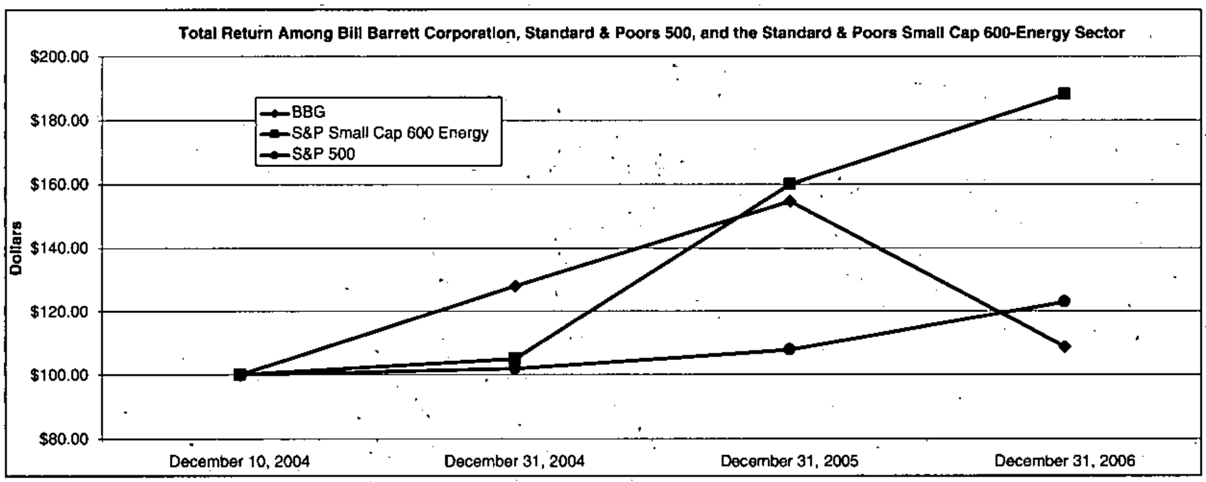
(1) The weighted average exercise price relates to the 2,429,069 outstanding options included in column (a). It does not relate to the 254,524 nonvested equity shares of common stock (restricted stock) that also are included in column (a) but that do not contain an exercise price.

Stockholder Return Performance Presentation

As required by applicable rules of the SEC, the performance graph shown below was prepared based upon the following assumptions:

1. $100 was invested in our common stock at $25.00 per share on December 10, 2004 (the first full trading day following the effective date of the Company's registration statement filed in connection with the initial public offering of the Company's common stock), and $100 was invested in each of the Standard & Poors 500 Index and the Standard and Poors Small Cap 600 Index-Energy Sector at the closing price on December 9, 2004.

2. Dividends are reinvested on the ex-dividend dates.



	December 10, 2004 (1)	December 31, 2004	December 31, 2005	December 31, 2006
BBG	$100.00	$127.96	$154.44	$108.84
S&P Small Cap 600- Energy	$100.00	$105.04	$159.85	$188.03
S&P 500	$100.00	$102.00	$107.88	$122.90

(1) December 10, 2004 was the first full trading day following the effective date of the Company's registration statement filed in connection with the initial public offering of its common stock.

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, 2004, 2005, and 2006. 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 Financial Information

The consolidated income statement information for the years ended December 31, 2004, 2005, and 2006 and the balance sheet information as of December 31, 2005 and 2006 are derived from our audited financial statements included elsewhere in this report. The income statement information for the period from January 7, 2002 (inception) through December 31, 2002 and the year ended December 31, 2003 and the balance sheet information at December 31, 2002, 2003 and 2004 is derived from audited financial statements that are not included in this report.

	Period from January 7, 2002 (inception) through December 31, 2002	2003	Year Ended December 31, 2004	2005	2006
	(in thousands, except per share data)				
Statement of Operations Data:					
Production revenues (1)	$16,007	$ 75,252	$165,843	$ 284,406	$ 344,127
Other revenues	74	184	4,137	4,353	31,202
Operating expenses:					
Lease operating expense	2,231	8,462	14,592	19,585	29,768
Gathering and transportation expense	229	3,646	5,968	11,950	15,721
Production tax expense	2,021	9,815	20,087	33,465	25,886
Exploration expense	1,592	3,655	12,661	10,930	9,390
Impairment, dry hole costs and abandonment expense	—	4,274	24,011	55,353	12,824
Depreciation, depletion and amortization	9,162	30,724	68,202	89,499	138,549
General and administrative	5,476	14,213	18,061	24,540	27,752
Non-cash stock-based compensation expense	1,322	3,637	3,031	3,212	6,491
Total operating expenses	22,033	78,426	166,613	248,534	266,381
Operating (loss) income	(5,952)	(2,990)	3,367	40,225	108,948
Other income (expense):					
Interest income	303	123	437	1,977	2,527
Interest expense	(65)	(1,431)	(9,945)	(3,175)	(10,339)
Loss on sale of securities	(1,465)	—	—	—	—
Total other expense	(1,227)	(1,308)	(9,508)	(1,198)	(7,812)
Income (loss) before income taxes	(7,179)	(4,298)	(6,141)	39,027	101,136
Provision for (benefit from) income taxes	(2,164)	(320)	(875)	15,222	39,125
Income (loss) from continuing operations	(5,015)	(3,978)	(5,266)	23,805	62,011
Income from discontinued operations (net of taxes)	27	—	—	—	—
Net income (loss)	(4,988)	(3,978)	(5,266)	23,805	62,011
Less deemed dividends on preferred stock	—	—	(36,343)	—	—
Less cumulative dividends on preferred stock	(4,430)	(12,682)	(18,633)	—	—
Net income (loss) attributable to common stockholders	$(9,418)	$(16,660)	$(60,242)	$ 23,805	$ 62,011
Income (loss) per common share (2):					
Basic	$(18.02)	$ (19.38)	$ (15.40)	$ 0.55	$ 1.42
Diluted	$(18.02)	$ (19.38)	$ (15.40)	$ 0.55	$ 1.40
Weighted average number of common shares outstanding, basic (3)	522.7	859.4	3,912.3	43,238.3	43,694.8
Weighted average number of common shares outstanding, diluted	522.7	859.4	3,912.3	43,439.6	44,269.4

	Period from January 7, 2002 (inception) through December 31, 2002	2003	Year Ended December 31, 2004	2005	2006
			(in thousands)		
Selected Cash Flow and Other Financial Data:					
Net income (loss)	$ (4,988)	$ (3,978)	$ (5,266)	$ 23,805	$ 62,011
Depreciation, depletion, impairment and amortization	9,162	30,724	68,202	89,499	138,549
Other non-cash items	672	7,786	26,887	71,168	37,765
Change in assets and liabilities	(967)	(659)	(2,941)	(202)	(1,427)
Net cash provided by operating activities	$ 3,879	$ 33,873	$ 86,882	184,270	236,898
Capital expenditures (4)	$166,893	$186,327	$347,520 (5)	$347,427 (5)	$501,161 (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 initial public offering in December 2004.

(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 for the year ended December 31, 2004 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 upon the completion of our initial public offering in December 2004.

(4) Excludes future reclamation liability accruals of $1.0 million, $2.9 million, $7.1 million, $10.7 million and $6.3 million in 2002, 2003, 2004, 2005 and 2006, respectively, and includes exploration, dry hole and abandonment costs, which are expensed under successful efforts accounting, of $1.6 million, $6.1 million, $36.2 million, $23.6 and $21.0 million in 2002, 2003, 2004, 2005, and 2006, respectively. Also includes furniture, fixtures and equipment costs of $1.1 million in 2002, $1.8 million in 2003, $2.1 million in 2004, $2.6 million in 2005, and $2.4 million in 2006.

(5) Not deducted from the amount is $8.8 million, $13.8 million and $92.3 million of proceeds received principally from the sale of interests in oil and gas properties during the years ended December 31, 2004, 2005 and 2006, respectively.

	As of December 31, 2002	2003	2004	2005	2006
			(in thousands)		
Balance Sheet Data:					
Cash and cash equivalents	$ 5,713	$ 16,034	$ 99,926	$ 68,282	$ 41,322
Other current assets	7,246	19,613	37,964	73,036	97,185
Oil and natural gas properties, net of accumulated depreciation, depletion, amortization and impairment	144,305	307,920	549,182	737,992	951,132
Other property and equipment, net of depreciation	896	1,539	2,983	7,956	11,967
Oil and natural gas properties held for sale, net of accumulated depreciation, depletion, amortization and impairment	12,067	—	—	—	75,496
Other assets	2,465	2,663	6,103	1,679	10,299
Total assets	$172,692	$347,769	$696,158	$888,945	$1,187,401
Current liabilities	$ 10,873	$ 46,156	$ 62,106	$132,798	$ 119,795
Long-term debt	36,900	58,900	—	86,000	188,000
Other long-term liabilities	1,117	4,387	14,320	39,364	123,209
Stockholders' equity	123,802	238,326	619,732	630,783	756,397
Total liabilities and stockholders' equity	$172,692	$347,769	$696,158	$888,945	$1,187,401

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 "Item 1A. Risk Factors" and the "Cautionary Note Regarding Forward-Looking Statements", 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 15, 2004, we completed our initial public offering in which 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. Substantially all of our revenues are generated through the sale of natural gas and oil production at market prices. Approximately 92% of our December 2006 production volume 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"). In May 2006, we acquired properties in the Powder River Basin consisting of approximately 84,300 gross (52,000 net) acres of oil and gas leasehold interests of coal bed methane properties in the Powder River Basin of Wyoming. 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
Powder River Basin	May 2006	79

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 equity investments in us, our bank line of credit, cash flow from operations and, in the case of the Piceance Basin properties, a bridge loan that we repaid in December 2004 with a portion of the proceeds from our initial public offering. 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. The May 2006 acquisition included properties in the Powder River Basin of Wyoming. Our activities are now focused on evaluating and developing our asset base in the areas mentioned above, as well as in other non-core exploratory projects, by increasing our acreage positions and evaluating potential acquisitions.

As of December 31, 2006, we had 428 Bcfe of estimated net proved reserves with a Standardized Measure of \$529 million (at \$4.46 CIG and \$61.06 WTI). As of December 31, 2005, we had 341 Bcfe of estimated net proved reserves with a Standardized Measure of \$782 million (at \$7.72 CIG and \$61.04 WTI), while at December 31, 2004, we had 292 Bcfe of estimated net proved reserves with a Standardized Measure of \$466 million (at \$5.52 CIG and \$43.46 WTI).

The average sales prices received for natural gas, before the effects of hedging contracts, for the years ended December 31, 2004, 2005, and 2006 were \$5.53 per Mcf, \$7.73 per Mcf and \$5.94 per Mcf respectively. Before the effect of hedging contracts, our average prices received for oil for the years ended December 31, 2004, 2005 and 2006 were \$39.49 per Bbl, \$53.69 per Bbl and \$59.39 per Bbl, respectively.

Higher oil and natural gas prices over the past several years 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 we received in 2006. In addition, we hedge a portion of our expected production. 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:

	Year Ended December 31, 2004	Year Ended December 31, 2005	2004 to 2005 Increase (Decrease) Amount	2004 to 2005 Increase (Decrease) Percent	Year Ended December 31, 2006	2005 to 2006 Increase (Decrease) Amount	2005 to 2006 Increase (Decrease) Percent
			(in thousands)				
Operating Results:							
Operating Revenues							
Oil and gas production	$165,843	$284,406	$118,563	71%	$344,127	$ 59,721	21%
Other	4,137	4,353	216	5%	31,202	26,849	617%
Operating Expenses							
Lease operating expense	14,592	19,585	4,993	34%	29,768	10,183	52%
Gathering and transportation expense	5,968	11,950	5,982	100%	15,721	3,771	32%
Production tax expense	20,087	33,465	13,378	67%	25,886	(7,579)	(23)%
Exploration expense	12,661	10,930	(1,731)	(14)%	9,390	(1,540)	(14)%
Impairment, dry hole costs and abandonment expense	24,011	55,353	31,342	131%	12,824	(42,529)	(77)%
Depreciation, depletion and amortization	68,202	89,499	21,297	31%	138,549	49,050	55%
General and administrative	18,061	24,540	6,479	36%	27,752	3,212	13%
Non-cash stock-based compensation expense (1)	3,031	3,212	181	6%	6,491	3,279	102%
Total operating expenses	$166,613	$248,534	$ 81,921	49%	$266,381	$ 17,847	7%
Production Data:							
Natural gas (MMcf)	28,864	36,287	7,423	26%	47,928	11,641	32%
Oil (MBbls)	474	523	49	10%	696	173	33%
Combined volumes (MMcfe)	31,708	39,425	7,716	24%	52,104	12,679	32%
Daily combined volumes (Mmcfe/d)	87	108	21	24%	143	35	32%
Average Prices (2):							
Natural gas (per Mcf)	$ 5.10	$ 7.16	$ 2.06	40%	$ 6.40	$ (0.76)	(11)%
Oil (per Bbl)	39.49	46.68	7.19	18%	53.50	6.82	15%
Combined (per Mcfe)	5.23	7.21	1.98	38%	6.60	(0.61)	(8)%
Average Costs (per Mcfe):							
Lease operating expense	$ 0.46	$ 0.50	$ 0.04	9%	$ 0.57	$ 0.07	14%
Gathering and transportation expense	0.19	0.30	0.11	58%	0.30	0.00	0%
Production tax expense	0.63	0.85	0.22	35%	0.50	(0.35)	(41)%
Depreciation, depletion and amortization (3)	2.15	2.27	0.12	6%	2.69	0.40	18%
General and administrative	0.57	0.62	0.07	13%	0.53	(0.09)	(15)%

(1) Non-cash stock-based compensation is presented herein as a separate line item but is combined with general and administrative expense for a total of $21.1 million, $27.8 million and $34.2 million for the years ended December 31, 2004, 2005 and 2006, respectively, in the Consolidated Statement of Operations.

Management believes the separate presentation of the non-cash component of general and administrative expense is useful because the cash portion provides a better understanding of our required cash for general and administrative expenses. We also believe that this disclosure allows more accurate comparison to our peers, who may have higher or lower costs associated with equity grants.

(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 $12.4 million and $24.3 million for the years ended December 31, 2004 and 2005, respectively, and increased by $18.1 million for the year ended December 31, 2006. Before the effect of hedging contracts, the average price we received for natural gas in 2006 was $5.94 per Mcf compared with $7.73 per Mcf in 2005 and $5.53 per Mcf in 2004.

(3) The depreciation, depletion and amortization per Mcfe for the year ended December 31, 2006 excludes the production associated with our properties held for sale throughout the year in the Uinta, Williston and DJ Basins as these properties were excluded from amortization beginning with the point at which these properties were classified as held for sale.

Year Ended December 31, 2006 Compared to Year Ended December 31, 2005

Production Revenues. Production revenues increased from $284.4 million for the year ended December 31, 2005 to $344.1 million for the year ended December 31, 2006 due to an increase in production, offset by decreases in natural gas prices. Production increases from the development of existing properties added approximately $83.7 million of production revenues, which were partially offset by lower natural gas prices that decreased revenues by $24.0 million. Significant decreases in product prices would significantly reduce our revenues from existing properties. See "—Quantitative and Qualitative Disclosure about Market Risk".

Total production volumes for the 2006 calendar year increased 32% from 2005 with increases in production from the Uinta, Williston and Piceance Basins, which increased 115%, 3% and 179% respectively. The increase in production was partially offset by decreases in the Wind River and Powder River Basins, which decreased 27% and 17%, respectively, from 2005. Additional information concerning production is in the following table.

	Year Ended December 31,					
	2005			2006		
	Oil (MBbls)	Natural Gas (MMcf)	Total (MMcfe)	Oil (MBbls)	Natural Gas (MMcf)	Total (MMcfe)
Wind River Basin	68	15,157	15,565	46	11,156	11,432
Uinta Basin	8	7,612	7,660	43	16,195	16,453
Powder River Basin	—	8,405	8,405	—	7,002	7,002
Williston Basin	376	149	2,405	389	145	2,479
Piceance Basin	45	4,937	5,207	193	13,377	14,535
Other	26	27	183	25	53	203
Total	523	36,287	39,425	696	47,928	52,104

The production decrease in the Wind River Basin is due to natural production declines in our Cave Gulch, Cooper Reservoir and Wallace Creek fields that occurred throughout 2006. This decrease in production is partially offset by our new deep Lakota discovery well, the Bullfrog 33-19, which had first production in June 2006. The production increase in the Uinta Basin is due to development activities in West Tavaputs, including the exploration success of the Peters Point 4-12D-13-16 Deep well, which was put on production in November 2006, along with first production from our initial Lake Canyon discovery wells. Furthermore, the completion of a third party gas processing facility in mid-August 2006 increased our gross takeaway capacity in the West Tavaputs field by approximately 20 MMcf/d. The production decrease in the Powder River Basin is due to natural production declines in our existing mature fields and the lag time between drilling of coal bed methane well and production of natural gas while dewatering occurs, which are partially offset by the production from the properties we acquired from CH4 in early May 2006. In late August 2006, we sold the majority of the then producing properties acquired in the CH4 acquisition. As of December 31, 2006, we had 127 net operated coal bed methane wells in the dewatering stage. The production increase in the Piceance Basin is the result of our continued development activities.

Hedging Activities. In 2006, we hedged approximately 43% of our natural gas volumes and 39% of our oil volumes, resulting in an increase in gas revenues of $22.2 million, offset by a reduction in oil revenues of $4.1 million. In 2005 we hedged approximately 50% of our natural gas volumes and 49% of our oil volumes, resulting in a reduction in both natural gas and oil revenues of $20.7 million and $3.6 million respectively.

Other Operating Revenues. Other operating revenues increased from $4.4 million for the year ended December 31, 2005 to $31.2 million for the year ended December 31, 2006. The increase is primarily due to gains realized on joint exploration agreements and other property sales in the Powder River, Paradox, Williston, Wind River, Big Horn, Montana Overthrust, Uinta and DJ Basins.

Lease Operating Expense and Gathering and Transportation Expense. Our lease operating expense increased slightly to $0.57 per Mcfe in 2006 compared to $0.50 in 2005, while our gathering and transportation expense remained consistent at $0.30 per Mcfe in 2006. The increase in lease operating expense is primarily due to an increase in the Powder River Basin from $0.60 per Mcfe in 2005 to $1.05 per Mcfe in 2006. This increase on a per Mcfe basis in the Powder River Basin is due to natural production declines in our mature fields, and the higher water handling charges on dewatering wells in new pilot areas that have no offsetting gas production as yet. As of December 31, 2006, we had 127 net operated coal bed methane wells in the dewatering stage. Lease operating expense also increased in the Williston Basin from $1.10 per Mcfe in 2005 to $1.50 per Mcfe in 2006 as a result of the high volumes of water being produced from wells recently put onto production.

We have entered into long-term firm transportation contracts on a portion of our production to guarantee capacity on major pipelines to avoid possible production curtailments that may arise due to limited pipeline capacity. The majority of our long-term firm transportation agreements are for gas production from the Piceance and Uinta Basins where we expect to spend a significant portion of our capital budget in future years. Included in the above gathering and transportation expense per Mcfe is $0.05 and $0.07 of transportation expense from long-term contracts for the years ended December 31, 2005 and 2006, respectively.

Production Tax Expense. Total production taxes decreased from $33.5 million in 2005 to $25.9 million in 2006 . Although we realized higher production revenues from the increase in our production volumes, our overall production taxes decreased as a larger portion of our revenues were generated from areas with lower tax rates. Production taxes as a percentage of natural gas and oil sales before hedging adjustments decreased from 10.8% in 2005 to 7.9% in 2006. 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, as we continue to develop our acreage position in the Piceance Basin in the state of Colorado, where the production tax rate for the state will approximate 6%, which is lower than our current overall rate, our overall production tax rate will decrease as more volumes are added from this lower tax rate area. Conversely, our overall production tax rate will increase as more volumes are added from higher tax areas such as the state of Wyoming.

Exploration Expense. Exploration expense decreased from $10.9 million in 2005 to $9.4 million in 2006. Exploration expense for 2005 includes $9.4 million for seismic programs principally in the Uinta, Wind River and Big Horn Basins, and Montana Overthrust, and $1.5 million for delay rentals and other costs. Exploration expense for 2006 included $8.1 million for seismic programs, principally in the Montana Overthrust, Wind River, Paradox, and DJ Basins, and $1.3 million for delay rentals and other costs.

Impairment, Dry Hole Costs and Abandonment Expense. Our impairment, dry hole costs and abandonment expense decreased from $55.3 million in 2005 to $12.8 million in 2006. During 2005, impairment expense was $42.7 million, dry hole costs were $11.1 million for dry holes in the Wind River, Green River, Uinta and Williston Basins, and abandonment expense was $1.5 million. The impairment expense is the result of a $29.5 million impairment charge in the Cooper Reservoir field, an $11.3 million impairment charge in the Talon field, and a $1.9 million impairment charge in the East Madden field, all of which are located in the Wind River Basin. During the quarter ended June 30, 2005, production from existing and recently drilled infill wells in the Cooper Reservoir field declined more rapidly than anticipated, indicating well interference and limited downspacing opportunities. In the Talon and East Madden fields, production from exploratory wells was at a rate that was not economic based on the capital investment. During 2006, impairment expense was $1.2 million, dry hole costs were $10.0 million for dry holes primarily in the Uinta and Williston Basins, and abandonment expense was $1.6 million. The impairment expense in 2006 related to our Cedar Camp and Tumbleweed properties within the Uinta Basin based upon our fair value analysis. We sold these properties in December 2006. Included in $10.0 million of dry hole costs for 2006 is $3.5 million related to the #1DLB, an exploration well located in the Lake Canyon area of the Uinta Basin. This well, which was completed in April 2006, was tested and determined to be commercial in the Wasatch formation and non-commercial in the zones below the Wasatch; thus, a proportionate share of the well cost is being expensed.

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. If proved reserves are not assigned to an exploratory well, 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, 2006 pending determination of whether the wells will be assigned proved reserves. The following table does not include $18.6 million related to exploratory wells in progress for which drilling had not been completed at December 31, 2006:

	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	$11,453	$11,501	$6,821	$21,179	$50,954

The majority of our exploratory wells that have been capitalized for a period greater than one year are located in the Powder River Basin. In this basin, we drill wells into various coal seams. In order to produce gas from the coal seams, a period of dewatering lasting from a few to 24 months, or in some cases longer, is required prior to obtaining sufficient gas production to justify capital expenditures for compression and gathering and to classify the reserves as proved.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization ("DD&A") expense was $138.5 million in 2006 compared to $89.5 million in 2005. In 2006, $27.7 million of the increase was due to the 32% increase in production and $21.3 million was due to an increased DD&A rate for 2006. In 2005, the weighted average DD&A rate was $2.27 per Mcfe compared to $2.69 per Mcfe in 2006. 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 2006, the relationship of capital expenditures, proved reserves and production from certain producing areas yielded a higher depletion rate than 2005. 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, excluding non-cash stock-based compensation, increased $3.2 million from $24.5 million in 2005 to $27.8 million in 2006. This increase was primarily due to increased personnel required to support our capital program and production levels. As of December 31, 2006, we had 138 full-time employees in our corporate office compared to 127 as of December 31, 2005. We also incurred $0.4 million of nonrecurring expenses during the year ended December 31, 2006 as a result of exploring financing options. On a per unit of production basis, general and administrative expense, excluding non-cash stock based compensation, decreased from $0.62 per Mcfe in 2005 to $0.53 per Mcfe in 2006. A significant portion of our general and administrative expense relates to the management of our capital expenditure program. As our capital investments have resulted in increased production levels, we expect general and administrative expense per unit of production to decrease.

Non-cash stock-based compensation expense included in general and administrative expense increased from $3.2 million in 2005 to $6.5 million in 2006. Non-cash stock-based compensation for 2005 and 2006 is related to vesting of the restricted common stock issued to management and employees upon our formation, our stock option plans and nonvested equity shares of common stock issued to employees. The increase in non-cash stock-based compensation expense is primarily due to the increased number of equity awards that were granted during the later part of 2005 and in 2006. Equity awards to employees generally were made in the first quarter of 2006 and were not made in the first quarter of 2005 because of the awards previously made in connection with our initial public offering in December 2004. The increase is also due to the acceleration of vesting of share-based awards for certain of our officers who left us during 2006. Additionally, we amended our 401(k) Plan on January 1, 2006 to increase our match of the employees' contribution from 4% up to 6%, of which 50% of the match is made with our common stock.

The components of non-cash stock-based compensation for 2005 and 2006 are shown in the following table.

	Year Ended December 31,	
	2005	2006
	(in thousands)	
Restricted common stock	$ 489	$ 38
Stock options and nonvested equity shares of common stock	2,723	5,938
Shares issued for 401(k) plan	—	515
Total	$3,212	$6,491

Restricted common stock, which was issued to founding management and employees of the Company on January 30, 2002, 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. As of January 31, 2006, the restricted common stock was 100% dollar vested and 100% time vested and the remaining compensation expense was fully recognized.

Interest Expense. Interest expense increased $7.1 million to $10.3 million in 2006 compared to $3.2 million in 2005. The increase was due to higher debt levels during 2006 to fund exploration and development activities and a lack of a need to draw on our credit facility until the third quarter of 2005 due to the availability of the proceeds from our initial public offering in December 2004. As a result, the interest expense during the year of 2005 was primarily comprised of debt commitment fees and amortization of deferred financing costs. The weighted average outstanding balances under our credit facility for the years ended December 31, 2005 and 2006 were $23.4 million and $158.9 million, respectively.

Interest cost is capitalized as a component of property cost for significant exploration and development projects that require greater than six months to be readied for their intended use. Until the third quarter of 2006, we had not capitalized any interest expense. The weighted average interest rate used to capitalize interest for the current year was 7.1%, including interest and commitment fees paid on the unused portion of the credit facility and amortization of deferred financing costs. We capitalized interest costs of $1.0 million for the year ended December 31, 2006.

Income Tax Expense. Our effective tax rate was 38.7% in 2006 and 39.0% in 2005. Our effective tax rates for 2006 and 2005 differ from the federal and state statutory rates primarily because of the amount of stock-based compensation expense recorded for financial statement purposes under Accounting Principles Board ("APB")

Opinion No. 25 and SFAS No. 123(R) that is not deductible for income tax purposes. These non-deductible permanent differences caused our effective tax rate to be higher than the rate that would have been effective if the costs would have been deductible. All of our income tax benefits and liabilities to date are deferred. While we have net operating loss carryforwards and deductions from our drilling activities, we are subject to the federal alternative minimum tax ("AMT") and state income tax. We expect to incur cash payments associated with these taxes within the next year.

Net Income. We generated net income of $62.0 million in 2006 compared to net income of $23.8 million in 2005. Our net income increased due to the increase in production and an increase in other operating revenues, as previously discussed in this section. Additionally, impairment, dry hole costs and abandonment expense decreased along with exploration expense and production tax expense. Offsetting the increase in operating revenues were increases in operating expenses, interest expense, and the provision for income taxes during 2006 as compared to 2005.

Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

Production Revenues. Production revenues increased from $165.8 million for the year ended December 31, 2004 to $284.4 million for the year ended December 31, 2005 due to both an increase in production and increases in natural gas and oil prices. Price increases added approximately $62.8 million of production revenues, and production increases from the development of existing properties added approximately $55.8 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 $4.4 million for the year ended December 31, 2005, which were principally gains on disposals of oil and gas properties.

Total production volumes for 2005 increased 24% from 2004 with increases in all of the major producing basins with the exception of the Wind River Basin, which showed a decrease of 15% from 2004. Additional information concerning production is in the following table.

	Year Ended December 31,					
	2004			2005		
	Oil (MBbls)	Natural Gas (MMcf)	Total (MMcfe)	Oil (MBbls)	Natural Gas (MMcf)	Total (MMcfe)
Wind River Basin	107	17,676	18,318	68	15,157	15,565
Uinta Basin	6	5,295	5,331	8	7,612	7,660
Powder River Basin	—	4,934	4,934	—	8,405	8,405
Williston Basin	329	162	2,136	376	149	2,405
Piceance Basin	5	779	809	45	4,937	5,207
Other	27	18	180	26	27	183
Total	474	28,864	31,708	523	36,287	39,425

The production decrease in the Wind River Basin is due to natural production declines in our Cave Gulch, Cooper Reservoir and Wallace Creek fields that occurred throughout 2005. These natural production declines in the Wind River Basin were partially offset as the result of the exploration success of the Bullfrog Federal 14-18 well, the successful re-stimulation of the Cave Gulch 1-29 well, and of our development activities in the Talon field. Both the Bullfrog Federal 14-18 and the Cave Gulch 1-29 were put on production in July 2005. The production increase in the Uinta Basin is due to development activities in West Tavaputs along with the exploration success of the Peters Point 6-7D well, which was put on production in October 2005. The production increase in the Powder River Basin reflects the success of our development activities throughout 2005. The production increase in the Williston Basin is principally due to continued exploration and development activities on our properties. The production increase in the Piceance Basin is the result of a full year of production and our development activities on properties we acquired in September 2004.

Hedging Activities. In 2005, we hedged approximately 50% of our natural gas volumes and 49% of our oil volumes, resulting in a reduction in revenues of $24.3 million. In 2004 we hedged approximately 38% of our natural gas volumes, incurring a reduction in revenues of $12.4 million. No oil volumes were hedged in 2004.

Lease Operating Expense and Gathering and Transportation Expense. Our lease operating expense increased to $0.50 per Mcfe in 2005 compared to $0.46 in 2004, while our gathering and transportation expense increased from $0.19 per Mcfe in 2004 to $0.30 per Mcfe in 2005. The increase in lease operating expense is primarily the result of equipment rentals and diesel fuel costs associated with a temporary electrical power supply for new wells in the Powder River Basin. The increase in gathering and transportation expense is principally attributable to an increase of $5.4 million for our CBM properties in the Powder River Basin relating to increased third party charges for compressor fuel, processing charges incurred for removal of CO_2 in order to meet pipeline specifications, the relative increase in production in the Powder River Basin, which is a higher gathering cost area as compared to our conventional gas areas, and firm transportation fees we commenced incurring in 2005. We have entered into long-term firm transportation contracts on a portion of our production to guarantee capacity on major pipelines to avoid possible production curtailments that may arise due to limited pipeline capacity in the Wind River, Uinta and Powder River Basins.

Production Tax Expense. Total production taxes increased from $20.1 million in 2004 to $33.5 million in 2005 as a result of higher production revenues, which increased primarily due to higher prices received and higher volumes produced in 2005 compared to 2004. Production taxes as a percentage of natural gas and oil sales before hedging adjustments decreased from 11.3% in 2004 to 10.8% in 2005. 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.

Exploration Expense. Exploration expense decreased from $12.7 million in 2004 to $10.9 million in 2005. The costs in 2004 include $11.3 million for seismic programs primarily in the DJ, Wind River and Uinta Basins and $1.4 million for delay rentals and other costs. The costs in the 2005 period include $9.4 million for seismic programs principally in the Uinta, Wind River and Big Horn Basins, and Montana Overthrust, and $1.5 million for delay rentals and other costs.

Impairment, Dry Hole Costs and Abandonment Expense. Our impairment, dry hole costs and abandonment expense increased from $24.0 million in 2004 to $55.3 million in 2005. During 2004, impairment expense was $0.5 million, dry hole costs were $23.0 million for exploratory dry holes primarily in the Wind River and Uinta Basins, and abandonment expense was $0.5 million. During 2005, impairment expense was $42.7 million, dry hole costs were $11.1 million for dry holes in the Wind River, Green River, Uinta and Williston Basins, and abandonment expense was $1.5 million. The impairment expense is the result of a $29.5 million impairment charge in the Cooper Reservoir field, $11.3 million impairment charge in the Talon field, and $1.9 million impairment charge in the East Madden field, all of which are located in the Wind River Basin. During the quarter ended June 30, 2005, production from existing and recently drilled infill wells in the Cooper Reservoir field declined more rapidly than anticipated indicating well interference and limited downspacing opportunities. In the Talon and East Madden fields, production from exploratory wells was at a rate that was not economic based on the capital investment.

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, 2005 pending determination of whether the wells will be assigned proved reserves. The following table does not include $7.1 million related to exploratory wells in progress for which drilling had not been completed at December 31, 2005:

	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	$23,182	$19,194	$8,646	$3,418	$54,440

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense was $89.5 million in 2005 compared to $68.2 million in 2004. The 24% increase in production accounted for $16.6 million of the increase, and $4.7 million was due to an increased DD&A rate for 2005. In 2004, the weighted average DD&A rate was $2.15 per Mcfe compared to $2.27 per Mcfe in 2005. 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 2005, the relationship of capital expenditures, proved reserves and production from certain producing areas yielded a higher depletion rate than 2004. 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 $6.5 million from $18.0 million in 2004 to $24.5 million in 2005. This increase was primarily due to increased personnel required to support our capital expenditure program and production levels. As of December 31, 2005, we had 127 full-time employees in our corporate office compared to 101 as of December 31, 2004. On a per unit of production basis, general and administrative expense increased from $0.57 per Mcfe in 2004 to $0.62 per Mcfe in 2005.

Non-cash stock-based compensation expense included in general and administrative expense was $3.0 million in 2004 compared to $3.2 million in 2005. Non-cash stock-based compensation for 2004 is related to the vesting of the restricted common stock issued to management and employees upon our formation of our stock option plans and purchases by employees of Series B convertible preferred stock at less than estimated fair market value. Non-cash stock-based compensation for 2005 is also related to the vesting of the restricted common stock issued to management upon our formation and our stock option plans, as well as nonvested equity shares of common stock issued to employees in 2005. The increase in expense was due principally to the recognition of compensation cost over the requisite service period for those awards granted in December 2004 and during 2005. The components of non-cash stock-based compensation for 2004 and 2005 are shown in the following table.

	Year Ended December 31,	
	2004	2005
	(in thousands)	
Restricted common stock	$2,044	$ 489
Stock options and nonvested equity shares of common stock	705	2,723
Employee purchases of Series B convertible preferred stock	282	—
Total	$3,031	$3,212

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, 2005, the restricted common stock was 100% dollar vested and 98.3% 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, 2005, a balance of $0.04 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 decreased $6.7 million to $3.2 million in 2005 compared to 2004. The decrease was due to higher debt levels in 2004 to fund acquisitions and development activities and a lack of a need to draw on our credit facility until the third quarter of 2005 due to the availability of the net proceeds from our initial public offering in December 2004. The weighted average outstanding balance under our credit facility was $73.7 million for 2004 as compared to $23.4 million for 2005. In addition to increased borrowings under our credit facility in 2004, 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 initial public offering. The bridge loan was terminated at that time so that it had no outstanding balance and no interest expense for the year ended December 31, 2005. As of December 31, 2005, no interest had been capitalized.

Income Tax Expense. Our effective tax rate was 39% in 2005 and 14% in 2004. Our effective tax rate for 2005 and 2004 differs from the statutory rates primarily because of the amount of stock-based compensation expense recorded for financial statement purposes under APB Opinion No. 25 and SFAS No. 123(R) that is not deductible for income tax purposes. Due to our net income position for the year ended December 31, 2005, these non-deductible permanent differences caused our effective tax rate to be higher than the rate that would have been effective if the costs would have been deductible. For the year ended December 31, 2004, we were in a net loss position and the non-deductible stock-based compensation expense caused the net loss to be greater than the net loss upon which income taxes are computed, which decreased our effective tax rate. All of our income tax benefits and provisions as of December 31, 2005 were deferred.

Net Income (Loss). We generated net income of $23.8 million in 2005 compared to a net loss of $5.3 million in 2004. The primary reasons for the increase include an increase in total revenues of $118.8 million, an increase in interest income of $1.5 million, a decrease in exploration expense of $1.7 million and a decrease in interest expense of $6.7 million. This was offset by an increase in non-cash impairment, dry hole costs and abandonment expense of $31.3 million, an increase in depreciation, depletion and amortization of $21.3 million, and increase in other operating expenses of $31.0 million and an increase in income tax expense of $16.0 million.

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, proceeds from joint exploration agreements, and a bridge loan to finance our September 2004 acquisition of properties in the Piceance Basin in Colorado. Our primary use of capital has been for the acquisition, development, and exploration of natural gas and oil 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, 2006, our balance sheet reflected a cash balance of $41.3 million with a balance of $188.0 million outstanding on our credit facility.

Cash Flow from Operating Activities

Net cash provided by operating activities was $86.9 million, $184.3 million and $236.9 million in 2004, 2005 and 2006, respectively. The increases in net cash provided by operating activities were substantially due to increased production revenues, partially offset by increased expenses, as discussed above in "—Results of Operations". Changes in assets and liabilities reduced cash flow from operations by $2.9 million, $0.02 million, and $1.4 million in 2004, 2005 and 2006, 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. For additional information on the impact of changing prices on our financial position, see "—Quantitative and Qualitative Disclosure About Market Risk" below.

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, 2006, we had in place natural gas and crude oil collars and swaps covering portions of our 2007 and 2008 production. Our 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 assets in our Consolidated Balance Sheets based on scheduled delivery of the underlying production.

As of February 16, 2007, we had hedges in place for 39,960,000 MMBtu and 22,545,000 MMBtu of natural gas production for 2007 and 2008, respectively, and 292 MBbls and 183M Bbls of oil production for 2007 and 2008, respectively.

The table below summarizes the deliveries associated with the swap and collar contracts as of February 16, 2007:

Product	Deliveries Per Day	Quantity Type	Weighted Average Floor Pricing	Weighted Average Ceiling Pricing	Weighted Average Fixed Price	Index Price (1)	Contract Period
Cashless Collars:							
	15,000	MMBtu	$ 7.50	$12.25	n/a	CIGRM	11/1/2006 – 3/31/2007
	64,000	MMBtu	$ 6.07	$ 9.61	n/a	CIGRM	1/1/2007 – 12/31/2007
	800	Bbls	$55.00	$79.85	n/a	WTI	1/1/2007 – 12/31/2007
	35,000	MMBtu	$ 6.50	$10.00	n/a	CIGRM	1/1/2008 – 12/31/2008
	500	Bbls	$70.00	$80.15	n/a	WTI	1/1/2008 – 12/31/2008
Swap Contracts:							
	10,000	MMBtu	n/a	n/a	$6.50	CIGRM	2/1/2007 – 2/28/2007
	5,000	MMBtu	n/a	n/a	$5.21	CIGRM	2/1/2007 – 10/31/2007
	20,000	MMBtu	n/a	n/a	$6.44	CIGRM	3/1/2007 – 3/31/2007
	45,000	MMBtu	n/a	n/a	$5.47	CIGRM	4/1/2007 – 10/31/2007
	55,000	MMBtu	n/a	n/a	$6.90	CIGRM	11/1/2007 – 3/31/2008
	10,000	MMBtu	n/a	n/a	$6.75	CIGRM	1/1/2008 – 12/31/2008
	5,000	MMBtu	n/a	n/a	$6.30	CIGRM	4/1/2008 – 10/31/2008

(1) 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 2007 and 2008, 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 financial institutions deemed by management as competent and competitive market makers.

Based on hedging contracts outstanding on December 31, 2006, our cash flow hedge positions from natural gas and oil derivatives had an estimated net pre-tax asset of $46.7 million recorded as both current and non-current assets, as appropriate. We will reclassify this amount to gains or losses included in natural gas and oil production operating revenues as the hedged production quantity is produced. Based on current projected market prices, the net amount of existing unrealized after-tax income as of December 31, 2006 to be reclassified from accumulated other comprehensive income to net income during 2007 would be $19.7 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 $501.2 million in 2006, $347.4 million in 2005 and $347.5 million in 2004. The total for 2006 includes $159.3 million for the acquisition of both proved and unevaluated properties and other real estate (including $36.8 million of a non-cash deferred tax liability associated with the difference between the tax basis of the properties acquired in the CH4 acquisition and the book basis attributed to the properties under the purchase method of accounting), $318.5 million for drilling, development, exploration and exploitation of natural gas and oil properties (including related gathering and facilities, but excluding exploratory dry holes, which are expensed under successful efforts accounting as exploration expense), $21.0 million related to geologic and geophysical costs and exploratory dry holes and abandonment costs, and $2.4 million for furniture, fixtures and equipment. The total for 2005 includes $28.2 million for acquisitions of properties and other real estate, $293.1 million for drilling, development, exploration and exploitation of natural gas and oil properties, $23.6 million related to geologic and geophysical costs and exploratory dry holes, and $2.5 million for furniture, fixtures and equipment. The total for 2004 includes $152.8 million for the acquisitions of properties, $156.4 million for drilling, development, exploration and exploitation of natural gas and oil properties, $36.2 million related to geologic and geophysical costs and exploratory dry holes, and $2.1 million for furniture, fixtures and equipment. For the years ended December 31, 2006, 2005 and 2004, we received $87.6 million, $13.8 million and $8.8 million, respectively, of proceeds principally from the sale of interests in oil and gas properties, which are not deducted from the capital expenditures presented above.

Unevaluated properties increased $52.9 million to $221.2 million, including $18.2 million related to unevaluated properties in the Williston and DJ Basins that currently are classified as held for sale, at December 31, 2006 from $168.3 million at December 31, 2005, principally from increases in leasehold, including the CH4 acquisition and wells in progress resulting from increased development and exploratory drilling activity during the year ended December 31, 2006.

Excluding acquisitions, our current capital budget for 2007 is $425-450 million, of which we plan to spend approximately $305-315 million for development drilling and facilities, $95-105 million on exploration drilling, $12-17 million for leasehold acquisitions, $9 million on geologic and geophysical costs, and $4 million for equipment and other costs. By basin, we plan to spend $170-175 million in the Piceance, $165-$180 million in the Uinta, $28-33 million in the Wind River, $25-$30 million in the Powder River, and $32-$37 in other areas. Based upon our current natural gas and oil price expectations and our hedge position for 2007, we anticipate that our operating cash flow, expected proceeds from property sales, and available borrowing capacity under our credit facility will be sufficient to fund our planned capital expenditures and other cash requirements for 2007. However, future cash flows are subject to a number of variables, including the level of natural gas and oil 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.

The amount, timing, and allocation of capital expenditures is generally discretionary and within our control. If natural gas and oil prices decline to levels below our acceptable levels or costs increase to levels above our acceptable levels, we could choose to defer a portion of these planned 2007 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.

Financing Activities

Credit Facility. Our current bank line of credit has a face value of $400.0 million, expandable up to $600.0 million. This credit facility was entered into on February 4, 2004 and was amended on September 1, 2004 and on March 17, 2006. The first amendment increased the borrowing base from $150.0 million to $200.0 million and the second increased the face value of the line of credit from $200.0 million to $400.0 million, increased the borrowing base from $200.0 million to $310.0 million, effective October 6, 2006, and extended the maturity date from February 4, 2007 to March 17, 2011. The amended credit facility bears interest, based on the borrowing base usage at the applicable London Interbank Offered Rate ("LIBOR") plus applicable margins ranging from 1.0% to 1.75%, 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 0.25%. We pay commitment fees ranging from 0.25% to 0.375% of the unused borrowing base. This facility is secured by natural gas and oil properties representing at least 80% of the value of our proved reserves and the pledge of all of the stock of our subsidiaries. At December 31, 2005, we had $86.0 million outstanding under our amended credit facility and, as of December 31, 2006, we had $188.0 million outstanding under the amended credit facility. For information concerning the effect of changes in interest rates on interest payments under this facility, see "—Quantitative and Qualitative Disclosure About Market Risk—Interest Rate Risks" below.

The amended credit facility contains certain financial covenants. As of December 31, 2006, we were in compliance with all of the financial covenants under the facility.

In December 2006, we entered into two interest rate derivative contracts to manage our exposure to changes in interest rates. The first contract was a floating-to-fixed interest rate swap for a notional amount of $10.0 million and the second was a floating-to-fixed interest rate collar for a notional amount of $10.0 million, both to terminate on December 12, 2009. Under the swap, we will make payments to (or receive payments from) the contract counterparty when the variable rate of one-month LIBOR falls below (or exceeds) the fixed rate of 4.70%. Under the collar we will make payments to (or receive payments from) the contract counterparty when the variable rate falls below the floor rate of 4.50% or exceeds the ceiling rate of 4.95%. Our interest rate derivative instruments have been designated as cash flow hedges in accordance with SFAS No. 133. The derivatives were structured to mirror the critical terms of the hedged debt instruments; therefore, no ineffectiveness has been recorded in earnings.

Since we did not enter into interest rate derivative contracts until December 2006, there were no settlement payments received or paid for the year ending December 31, 2006. Payments and receipts in future periods will be included in interest expense. We anticipate that all originally forecasted transactions will occur by the end of the originally specified time periods, and based on current projected interest rates, the net amount of existing unrealized after-tax income as of December 31, 2006 to be reclassified from accumulated other comprehensive income to net income during 2007 would be approximately $0.1 million. At December 31, 2006, the estimated fair value of the interest rate derivatives was a net asset of $0.1 million.

Contractual Obligations. A summary of our contractual obligations as of and subsequent to December 31, 2006 is provided in the following table.

	Payments Due By Year						
	2007	2008	2009	2010	2011	After 2011	Total
	(in thousands)						
Long-term debt (1)	$ —	$ —	$ —	$ —	$188,000	$ —	$188,000
Other commitments for developing oil and gas properties	25,640	2,705	—	—	—	—	28,345
Office and office equipment leases and other	1,625	1,504	1,540	1,593	450	—	6,712
Firm transportation and processing agreements	5,801	15,027	17,353	17,764	23,700	104,420	184,065
Asset retirement obligations (2)(3)	—	8,410	1,228	715	1,871	20,374	32,598
Total	$33,066	$27,646	$20,121	$20,072	$214,021	$124,794	$439,720

(1) Amount does not include future commitment fees, interest expense, or other fees on our credit facility because the credit facility is a floating rate instrument, and we cannot determine with accuracy the timing of future loan advances, repayments or future interest rates to be charged.

(2) Neither the ultimate settlement amounts nor the timing of our asset retirement obligations can be precisely determined in advance. See "—Critical Accounting Policies and Estimates," below for a more detailed discussion of the nature of the accounting estimates involved in estimating asset retirement obligations.

(3) Amount includes Asset Retirement Obligations of $3.4 million associated with Williston and Tri-State Basins, which are currently classified as held for sale.

We have entered into contracts that provide firm transportation capacity and processing rights on pipeline systems. The remaining terms on these contracts range from 1 to 11 years and require us to pay transportation demand and processing charges regardless of the amount of pipeline capacity utilized by us.

In addition to the commitments above, we have commitments for the purchase of facilities equipment as of and subsequent to December 31, 2006 for a total of $14.1 million.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our 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 consolidated financial statements. We provide expanded discussion of our more significant accounting policies, estimates and judgments below. We believe these accounting policies reflect our more significant estimates and assumptions used in preparation of our consolidated 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. If an exploratory well is not assigned proved reserves, 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. Interest cost is capitalized as a component of property cost for significant exploration and development projects that require greater than six months to be readied for their intended use.

The application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as developmental or exploratory, which will ultimately determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience.

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 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.

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 natural gas and oil 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. For the year ended December 31, 2005, we recorded impairment expense of $42.7 million related to the evaluated costs of the Talon, East Madden and Cooper Reservoir fields in Wyoming's Wind River Basin. The impairment expense of $1.2 million in 2006 related to our Cedar Camp and Tumbleweed properties within the Uinta Basin.

The successful efforts method of accounting can have a significant impact on the operational results reported when we are entering a new exploratory area in hopes of finding a gas and oil field that will be the focus of future development drilling activity. The initial exploratory wells may be unsuccessful and will be expensed. Seismic costs can be substantial, which will result in additional exploration expenses when incurred.

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, *Accounting for Asset Retirement Obligations*. 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 recognition of an asset retirement obligation ("ARO") requires that management make numerous estimates, assumptions and judgments regarding such factors as the estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used; inflation rates; and future advances in technology. In periods subsequent to initial measurement of the ARO, we must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to passage of time impact net income as accretion expense.

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. Our rate of recording DD&A is dependent upon our estimates of total proved and proved developed reserves, which incorporate assumptions regarding future development and abandonment costs as well as our level of capital spending. If the estimates of total proved or proved developed reserves decline, the rate at which we record DD&A expense increases, reducing our net income. This decline may result from lower market prices, which may make it uneconomic to drill for and produce higher cost fields. We are unable to predict changes in reserve quantity estimates as such quantities are dependent on the success of our exploitation and development program, as well as future economic conditions.

Oil and Gas Reserve Quantities

Our estimate of proved reserves is based on the 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. 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.

As of December 31, 2004, we revised our proved reserves downward by 32 Bcfe, excluding pricing revisions. The revision was primarily the result of encountering unexpected pressure depletion during infill drilling in the Wind River Basin and greater pressure depletion than expected in two areas in the Powder River Basin. The downward revision in the Wind River Basin in 2004 was 27.6 Bcfe. In this basin, 47.6% of the proved wells forecast in the Wind River Basin as of December 31, 2003 were 25% below forecast as of December 31, 2004. The reserve variance between the independent reserve engineers and the Company at year-end 2004 for this basin was 6.6 Bcfe with the independent engineers at the lower estimate. The downward revision in the Powder River Basin in 2004 was 7.2 Bcfe. In this basin, 29% of the proved wells forecast as of December 31, 2003 were 25% below forecast as of December 31, 2004. The reserve variance between the independent reserve engineers and the Company as of December 31, 2003 for this basin was 1.7 Bcfe with the independent engineers at the lower estimate.

As of December 31, 2005, we revised our proved reserves downward by 24.7 Bcfe, excluding pricing revisions, primarily as a result of a reduction in proved undeveloped reserves in the Piceance Basin due to the use of completion techniques performed from January through September 2005 that yielded results lower than our expectations as of December 31, 2004. Completion techniques used in subsequent periods have yielded more favorable results, which are reflected in upward revisions in 2006 reserve estimates in this area. The downward revision in the Piceance Basin in 2005 was 25.6 Bcfe. In this basin, 31% of the proved wells forecast as of December 31, 2004 were 25% below forecast as of December 31, 2005. The reserve variance between the independent reserve engineers and the Company as of December 31, 2004 for this basin was 13 Bcfe with the independent engineer at the lower estimate. The downward revision in the Powder River Basin in 2005 was 9.6 Bcfe. In this basin, 36% of the proved wells forecast as of December 31, 2004 were 25% below forecast as of December 31, 2005. The reserve variance between the independent reserve engineers and BBC as of December 31, 2004 for this basin was 3.8 Bcfe with the independent engineer at the lower estimate. An upward revision of 8.1 Bcfe occurred in the Uinta Basin in the West Tavaputs Field in 2005. In this basin, 31% of the proved wells forecast as of December 31, 2004 were 25% above forecast as of December 31, 2005. The reserve variance between the independent reserve engineers and BBC as of December 31, 2004 was 2.1 Bcfe with the independent engineer at the lower estimate.

During 2005, reviews of proved oil and gas properties in the Wind River Basin indicated a decline in the recoverability of their carrying value and the need for an impairment in the Cooper Reservoir, Talon and East Madden fields in the total amount of $42.7 million. We undertook a drilling program in Cooper Reservoir in 2003 and 2004 with the expectation of a specific economic reserve level. Actual reserve levels were less than our expectations which led to an impairment in the field in 2005. The impairments in the Talon and East Madden fields were the result of unsuccessful exploration programs.

As of December 31, 2006, we revised our proved reserves upward by 12.4 Bcfe, excluding pricing revisions. This revision was primarily the result of increased performance of wells drilled during the last half of 2005 and the first half of 2006. The pricing revision at year-end 2006 at prices of $4.46 per MMBtu of gas and $61.06 per barrel of oil, relative to year-end 2005 prices of $7.72 per MMBtu and $61.04 per barrel of oil, was downward 33.8 Bcfe. These prices were adjusted by lease for quality, transportation fees and regional price differences. The pricing revision at year-end 2006 at prices of $4.46 per MMBtu of gas and $61.06 per barrel of oil, relative to year-end 2005 prices of $7.72 per MMBtu and $61.04 per barrel of oil, was downward 33.8 Bcfe. These prices were adjusted by lease for quality, transportation fees and regional price differences.

Revenue Recognition

We record revenues from the sales of natural gas and oil when in the month that delivery to the customer has occurred and title has transferred. This occurs when natural gas or oil has been delivered to a pipeline or a tank lifting has occurred. We receive payment from one to three months after delivery. At the end of each month, we estimate the amount of production delivered to purchasers and the price we will receive. Variances between our estimated revenue and actual payment are recorded in the month the payment is received. However, differences have been insignificant.

We may have an interest with other producers in certain properties, in which case we use the sales method to account for natural 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' natural 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, 2005 and 2006 were not significant.

Derivative Instruments and Hedging Activities

We periodically uses derivative financial instruments to achieve a more predictable cash flow from our natural gas and oil production by reducing our exposure to price fluctuations. We also enter into derivative contracts to mitigate the risk of interest rate fluctuations. For the year ended December 31, 2006, these transactions included swaps and cashless collars. 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.

We have established the fair value of all derivative instruments using estimates determined by our counterparties. These values are based upon, among other things, futures prices, volatility, time to maturity and credit risk. The values we report in our financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

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, 2006, the fair value of the derivative positions for our oil and gas collars for 2007 and 2008 production was a net asset of $46.7 million. The deferred income tax effect on the fair value of derivatives at December 31, 2006 totaled $17.4 million, which is recorded in current and noncurrent deferred tax liabilities.

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 routinely assess the realizability of our deferred tax assets. If we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized under accounting standards, the tax asset would be reduced by a valuation allowance. We consider future taxable income in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and natural gas prices).

Stock-based Compensation

In December 2004, the Financial Accounting Standards Board ("FASB") issued SFAS No. 123(R), which revises SFAS No. 123, *Accounting for Stock-Based Compensation*, and supersedes 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. 123(R), 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 initially 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 $3.0 million, $3.2 million, and $6.5 million in 2004, 2005 and 2006, respectively, for the management stock awards, option grants, option modifications and nonvested equity shares of common stock, 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 April 16, 2004, the date of which is defined by SFAS No. 123(R) as the date we became a public company as a result of making a filing with a regulatory agency in preparation for the sale of equity securities in a public market), we adopted SFAS No. 123(R) using the modified prospective application effective October 1, 2004, whereby as of that date we began applying the provisions of SFAS No. 123(R) 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. 123(R)), we adopted SFAS No. 123(R) 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.

Acquisitions

The establishment of our initial asset base since our founding in January 2002 has included major acquisitions of natural gas and oil properties, which 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 to date we have 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 an acquisition 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 acquisition based upon our cost of capital.

We also apply these same general principles in arriving at the fair value of unevaluated properties acquired in an acquisition. 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.

New Accounting Pronouncements

In July 2006, the FASB issued FASB Interpretation ("FIN") No. 48, *Accounting for Uncertainty in Income Taxes.* FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes.* FIN 48 also prescribes a recognition threshold and measurement standard for the financial statement recognition and measurement of an income tax position taken or expected to be taken in a tax return. In addition, FIN 48 provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. We currently recognize income tax positions based on management's estimate of whether it is reasonably possible that a liability has been incurred for unrecognized income tax benefits by applying FASB Statement No. 5, *Accounting for Contingencies.* The provisions of FIN 48 became effective for us on January 1, 2007 and are to be applied to all tax positions upon initial application of this standard. Only tax positions that meet the more-likely-than-not recognition threshold at the effective date may be recognized or continue to be recognized upon adoption. The cumulative effect of applying the provisions of FIN 48 will be reported as an adjustment to the opening balance of retained earnings for the fiscal year of adoption. The Company has not yet determined the potential financial statement impact of adopting FIN 48.

In September 2006, the SEC issued Staff Accounting Bulletin ("SAB") No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements.* SAB 108 provides guidance on the consideration of effects of the prior year misstatements in quantifying current year misstatements for the purpose of a materiality assessment. Under SAB 108, registrants must quantify errors using both a balance sheet and income statement approach and evaluate whether either approach results in quantifying a misstatement that, when all relevant quantitative and qualitative factors are considered, is material. SAB 108 was effective for us as of December 31, 2006, and the adoption did not have an impact on our financial statements.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements.* SFAS No. 157 defines fair value, establishes a framework for measuring fair value, and expands disclosure requirements regarding fair value measurement. Where applicable, SFAS No. 157 simplifies and codifies fair value related guidance previously issued within U.S. generally accepted accounting principles. Although SFAS No. 157 does not require any new fair value measurements, its application may, for some entities, change current practice. SFAS No. 157 will be effective for the Company beginning January 1, 2008. We do not expect the adoption of SFAS No. 157 to have a material impact 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 natural gas and oil 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 natural gas and oil 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 natural gas and oil 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 including volatility in the differences between product prices at sales points and the applicable index price. Based on our average daily production and our price swap and collars contracts in place in 2006, our annual income before income taxes, including hedge settlements, for the year ended December 31, 2006 would have decreased by approximately $3.1 million for each $0.10 decrease per MMBtu in natural gas prices and approximately $0.2 million for each $1.00 per barrel 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 natural gas and oil price fluctuations. We do not hold or issue derivative instruments for speculative trading purposes.

As of February 16, 2007, we had hedges in place for 39,960,000 MMBtu and 22,545,000 MMBtu of natural gas production for 2007 and 2008, respectively, and 292 MBbls and 183 MBbls of oil production for 2007, and 2008, 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 December 31, 2005, the estimated fair value of our hedge positions was an asset of $46.7 million due to us from the counterparty.

Commodity Hedges

Commodity Swaps

Through price swaps, we have fixed the price we will receive on a portion of our natural gas production in 2007 and 2008. The weighted average price we will receive in 2007 for a Colorado Interstate Gas Rocky Mountain ("CIG") price is $5.83 per MMBtu and $6.78 per MMBtu in 2008. The table presented above under

Item 2, "Management's Discussion and Analysis of Financial Condition and Results of Operations—Cash Flow from Operating Activities," provides the deliveries associated with these arrangements as of February 16, 2007.

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.

Commodity Collars

Through price collars, we have fixed the minimum and maximum price we will receive on a portion of our natural gas production in 2007 and 2008. The weighted average minimum, or floor, price we will receive in 2007 is $6.15 per MMBtu for a CIG price and $6.50 per MMBtu in 2008. The weighted average maximum, or ceiling, price we will receive in 2007 and 2008 for a CIG price is $9.75 and $10.00 per MMBtu, respectively. We have also fixed the minimum price we will receive on a portion of our oil production in 2007 and 2008, when the collars are settled, based on a weighted average floor price of $55.00 and $70.00 per Bbl for a West Texas Intermediate ("WTI") price, respectively, and a weighted average maximum price of $79.85, and $80.15 WTI, 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 deliveries and floor and ceiling prices associated with these various arrangements as of February 16, 2007.

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, 2006, we had debt outstanding of $188.0 million, which bears interest at floating rates in accordance with our revolving credit facility. The average annual interest rate incurred on this debt for the year ended December 31, 2006 was 7.1%. A one hundred basis point (1.0%) increase in each of the average LIBOR rate and federal funds rate for the year ended December 31, 2006 would result in an estimated $1.6 million increase in interest expense assuming a similar average debt level to the year ended December 31, 2006.

Interest Rate Hedges

Through interest rate derivative contracts, we have attempted to mitigate its exposure to changes in interest rates. We entered into an interest rate swap for a notional amount of $10 million for a fixed interest rate of 4.70%. We also entered into an interest rate collar for a notional amount of $10 million whereas the interest rate has a fixed minimum and maximum rate of 4.50% and 4.95%, respectively.

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 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, effective.

Management's Report on Internal Control Over Financial Reporting. Internal control over financial reporting is defined in Rules 13a-15(f) and 15d-15(f) promulgated under the Securities Exchange Act of 1934, as amended, as a process designed by, or under the supervision of, the Company's principal executive and principal financial officers, or persons performing similar functions, and effected by the Company's Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes in accordance with U.S. generally accepted accounting principles and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the Company's assets;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of the Company's management and directors; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the financial statements.

Management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Under the supervision and with the participation of management, including the principal executive officer and principal financial officer, the Company conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation under the framework in Internal Control—Integrated Framework, management concluded that its internal control over financial reporting was effective as of December 31, 2006.

Management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2006 has been audited by Deloitte & Touche, LLP, an independent registered public accounting firm, as stated in their report which is included in this Annual Report on Form 10-K.

Changes in Internal Controls. There has been no change in our internal control over financial reporting during the fourth fiscal quarter of 2006 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that Bill Barrett Corporation and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2006 of the Company and our report dated February 27, 2007 expressed an unqualified opinion on those financial statements.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 27, 2007

Item 9B. Other Information

Not applicable.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information regarding our directors and executive officers will be included in an amendment to this Form 10-K or in the "Directors and Executive Officers" section of the proxy statement for the 2007 annual meeting of stockholders, in either case, to be filed within 120 days after December 31, 2006, and is incorporated by reference to this report.

Item 11. Executive Compensation

Information regarding executive compensation will be included in an amendment to this Form 10-K or in the "Executive Compensation" section of the proxy statement for the 2007 annual meeting of stockholders and is incorporated by reference to this report.

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

Information regarding beneficial ownership will be included in an amendment to this Form 10-K or in the "Beneficial Owners of Securities" section of the proxy statement for the 2007 annual meeting of stockholders and is incorporated by reference to this report.

Item 13. Certain Relationships and Related Transactions and Director Independence

Information regarding certain relationships and related transactions will be included in an amendment to this Form 10-K or in the "Transactions Between the Company and Related Parties" section of the proxy statement for the 2007 annual meeting of stockholders and is incorporated by reference to this report.

Item 14. Principal Accounting Fees and Services

Information regarding principal accountant fees and services will be included in an amendment to this Form 10-K or in the proxy statement for the 2007 annual meeting of stockholders and is incorporated by reference to this report.

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	Restated Certificate of Incorporation of Bill Barrett Corporation. [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.]
3.2	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.]
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	Form of Rights Agreement concerning Shareholder Rights Plan, which includes as Exhibit A thereto the Certificate of Designations of Series A Junior Participating Preferred Stock of Bill Barrett Corporation, and as Exhibits B thereto the Form of Right Certificate. [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.]
4.5	Form of Certificate of Designations of Series A Junior Participating Preferred Stock of Bill Barrett Corporation, included as Exhibit A to Exhibit 4.4 above.
4.6	Form of Right Certificate, included as Exhibit B to Exhibit 4.4 above.
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(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).]
10.3(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).]
10.4*	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).]
10.5(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).]

Exhibit Number	Description of Exhibits
10.5(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).]
10.6*	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).]
10.7*	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).]
10.8	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).]
10.9	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).]
10.10*	Form of Change in Control Severance Protection Agreement revised as of November 16, 2006 for named executive officers.
10.11*	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).]
10.12*	Revised Form of Stock Option Agreement for 2004 Stock Option Plan. [Incorporated by reference to Exhibit 10.19 to the Company's Annual Report on Form 10-K for the year ended December 31, 2005.]
10.13*	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 [Incorporated by reference to Exhibit 14 to the Company's Annual Report on Form 10-K for the year ended December 31, 2004.]
21.1	Subsidiaries of the Registrant.
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: February 27, 2007

By: /s/ FREDRICK J. BARRETT
Fredrick 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/ FREDRICK J. BARRETT **Fredrick J. Barrett**	Chairman of the Board of Directors and Chief Executive Officer (Principal Executive Officer)	February 27, 2007
/s/ FRANCIS B. BARRON **Francis B. Barron**	Chief Financial Officer (Principal Financial Officer)	February 27, 2007
/s/ JOSEPH N. JAGGERS **Joseph N. Jaggers**	Director; Chief Operating Officer and President	February 27, 2007
/s/ DAVID R. MACOSKO **David R. Macosko**	Vice President—Accounting (Principal Accounting Officer)	February 27, 2007
/s/ JAMES M. FITZGIBBONS **James M. Fitzgibbons**	Director	February 27, 2007
/s/ RANDY A. FOUTCH **Randy A. Foutch**	Director	February 27, 2007
/s/ JEFFREY A. HARRIS **Jeffrey A. Harris**	Director	February 27, 2007
/s/ ROGER L. JARVIS **Roger L. Jarvis**	Director	February 27, 2007
/s/ PHILIPPE S. E. SCHREIBER **Philippe S. E. Schreiber**	Director	February 27, 2007
/s/ RANDY STEIN **Randy Stein**	Director	February 27, 2007
/s/ MICHAEL E. WILEY **Michael E. Wiley**	Director	February 27, 2007

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, 2006 and 2005, and the related consolidated statements of operations, stockholders' equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes 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, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company 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".

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2007 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 27, 2007

BILL BARRETT CORPORATION

CONSOLIDATED BALANCE SHEETS

	As of December 31, 2005	As of December 31, 2006
	(in thousands, except share and per share data)	
Assets:		
Current Assets:		
Cash and cash equivalents	$ 68,282	$ 41,322
Accounts receivable, net of allowance for doubtful accounts of $171 and $284 as of December 31, 2005 and 2006, respectively	55,960	56,280
Prepayments and other current assets	6,598	2,697
Derivative assets	—	38,208
Deferred income taxes	10,478	—
Total current assets	141,318	138,507
Property and Equipment—At cost, successful efforts method for oil and gas properties:		
Proved oil and gas properties	804,421	1,114,536
Unevaluated oil and gas properties, excluded from amortization	168,284	202,946
Oil and gas properties held for sale, net, excluded from amortization	—	75,496
Furniture, equipment and other	11,533	14,696
	984,238	1,407,674
Accumulated depreciation, depletion, amortization and impairment	(238,290)	(369,079)
Total property and equipment, net	745,948	1,038,595
Deferred Financing Costs, Derivative Assets and Other	1,679	10,299
Total	$ 888,945	$1,187,401
Liabilities and Stockholders' Equity:		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 58,113	$ 69,519
Amounts payable to oil and gas property owners	19,697	13,933
Production taxes payable	25,930	22,348
Derivative liability and other current liabilities	29,058	34
Deferred income taxes	—	13,961
Total current liabilities	132,798	119,795
Note Payable to Bank	86,000	188,000
Asset Retirement Obligations	23,733	29,224
Liabilities Associated with Assets Held for Sale	—	3,374
Deferred Income Taxes	7,960	89,730
Other Noncurrent Liabilities	7,671	881
Stockholders' Equity:		
Common stock, $0.001 par value; authorized 150,000,000 shares; 43,695,286 and 44,141,453 shares issued and outstanding at December 31, 2005 and 2006, respectively, with 26,577 and 254,524 shares subject to restrictions, respectively	44	44
Additional paid-in capital	721,145	727,486
Accumulated deficit	(62,515)	(504)
Treasury stock, at cost: 124,024 shares at December 31, 2005 and zero shares at December 31, 2006	(5,180)	—
Accumulated other comprehensive income (loss)	(22,711)	29,371
Total stockholders' equity	630,783	756,397
Total	$ 888,945	$1,187,401

See notes to consolidated financial statements.

BILL BARRETT CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2004	2005	2006
	(in thousands, except share and per share amounts)		
Operating Revenues:			
Oil and gas production	$ 165,843	$ 284,406	$ 344,127
Other	4,137	4,353	31,202
Total operating revenues	169,980	288,759	375,329
Operating Expenses:			
Lease operating expense	14,592	19,585	29,768
Gathering and transportation expense	5,968	11,950	15,721
Production tax expense	20,087	33,465	25,886
Exploration expense	12,661	10,930	9,390
Impairment, dry hole costs and abandonment expense	24,011	55,353	12,824
Depreciation, depletion and amortization	68,202	89,499	138,549
General and administrative	21,092	27,752	34,243
Total operating expenses	166,613	248,534	266,381
Operating income	3,367	40,225	108,948
Other Income and Expense:			
Interest and other income	437	1,977	2,527
Interest expense	(9,945)	(3,175)	(10,339)
Total other income and expense	(9,508)	(1,198)	(7,812)
Income (Loss) before Income Taxes	(6,141)	39,027	101,136
Provision for (Benefit from) Income Taxes	(875)	15,222	39,125
Net Income (Loss)	(5,266)	23,805	62,011
Less deemed dividends on preferred stock	(36,343)	—	—
Less cumulative dividends on preferred stock	(18,633)	—	—
Net Income (Loss) Attributable to Common Stock	$ (60,242)	$ 23,805	$ 62,011
Net Income (Loss) Per Common Share, Basic	$ (15.40)	$ 0.55	$ 1.42
Net Income (Loss) Per Common Share, Diluted	$ (15.40)	$ 0.55	$ 1.40
Weighted Average Common Shares Outstanding, Basic	3,912,285	43,238,312	43,694,781
Weighted Average Common Shares Outstanding, Diluted	3,912,285	43,439,634	44,269,445

See notes to consolidated financial statements.

BILL BARRETT CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)

For the years ended December 31, 2004, 2005, and 2006

	Convertible Preferred Stock	Common Stock	Additional Paid-In Capital	Accumulated Deficit	Treasury Stock	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity	Comprehensive Income (Loss)
				(in thousands)				
Balance—December 31, 2003	$ 51	$ 9	$251,633	$ (8,966)	$ —	$ (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	—	—	3,031	—	—	—	3,031	—
Comprehensive loss:								
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	$709,578	$(86,320)	$ —	$ (3,569)	$619,732	
Exercise of options	—	1	7,149	—	(5,180)	—	1,970	$ —
Tax benefit from option exercises	—	—	1,227	—	—	—	1,227	—
Stock-based compensation	—	—	3,211	—	—	—	3,211	—
Other	—	—	(20)	—	—	—	(20)	—
Comprehensive income:								
Net income	—	—	—	23,805	—	—	23,805	23,805
Effect of derivative financial instruments, net of tax	—	—	—	—	—	(19,142)	(19,142)	(19,142)
Total comprehensive income								$ 4,663
Balance—December 31, 2005	$ —	$44	$721,145	$(62,515)	$ (5,180)	$(22,711)	$630,783	
Exercise of options	—	—	9,644	—	(5,059)	—	4,585	$ —
Stock-based compensation	—	—	6,944	—	—	—	6,944	—
Retirement of treasury stock	—	—	(10,239)	—	10,239	—	—	—
Other	—	—	(8)	—	—	—	(8)	—
Comprehensive income:								
Net income	—	—	—	62,011	—	—	62,011	62,011
Effect of derivative financial instruments, net of tax	—	—	—	—	—	52,082	52,082	52,082
Total comprehensive income								$114,093
Balance—December 31, 2006	$ —	$44	$727,486	$ (504)	$ —	$ 29,371	$756,397	

See notes to consolidated financial statements.

BILL BARRETT CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2004	2005	2006
		(in thousands)	
Operating Activities:			
Net Income (Loss)	$ (5,266)	$ 23,805	$ 62,011
Adjustments to reconcile to net cash provided by operations:			
Depreciation, depletion and amortization	68,202	89,499	138,549
Deferred income taxes	(875)	15,222	38,631
Impairments, dry hole costs and abandonment expense	24,011	55,353	12,824
Stock compensation and other non-cash charges	3,071	3,226	7,089
Amortization of deferred financing costs	4,409	1,175	556
Gain on sale of properties	(3,729)	(3,808)	(21,335)
Change in operating assets and liabilities:			
Accounts receivable	(15,802)	(24,811)	(320)
Prepayments and other assets	(2,037)	(1,891)	4,335
Accounts payable, accrued and other liabilities	3,664	1,700	3,904
Amounts payable to oil and gas property owners	3,450	14,307	(5,764)
Production taxes payable	7,784	10,493	(3,582)
Net cash provided by operating activities	86,882	184,270	236,898
Investing Activities:			
Additions to oil and gas properties, including acquisitions	(327,430)	(314,965)	(438,476)
Additions of furniture, equipment and other	(2,141)	(3,720)	(3,177)
Proceeds from sale of properties	8,811	13,842	78,339
Net cash used in investing activities	(320,760)	(304,843)	(363,314)
Financing Activities:			
Proceeds from debt	288,000	146,000	151,000
Principal payments on debt	(345,000)	(60,000)	(55,495)
Proceeds from sale of common and preferred stock	33,782	2,979	4,929
Proceeds from initial public offering	373,750	—	—
Offering costs	(26,384)	(84)	—
Deferred financing costs and other	(6,378)	34	(978)
Net cash provided by financing activities	317,770	88,929	99,456
Increase (Decrease) in Cash and Cash Equivalents	83,892	(31,644)	(26,960)
Beginning Cash and Cash Equivalents	16,034	99,926	68,282
Ending Cash and Cash Equivalents	$ 99,926	$ 68,282	$ 41,322

See notes to consolidated financial statements.

BILL BARRETT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
For the years ended December 31, 2004, 2005 and 2006

1. Organization

Bill Barrett Corporation (the "Company", "we" or "us"), a Delaware corporation, is an independent oil and gas company engaged in the exploration, development and production of natural gas and crude oil. Since its inception on January 7, 2002, the Company has conducted its activities principally in the Rocky Mountain region of the United States. On December 9, 2004, our Registration Statements on Form S-1 concerning our initial public offering ("IPO") were declared effective by the Securities and Exchange Commission (the "SEC"). The offering was completed on December 15, 2004.

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.

In the course of preparing the consolidated financial statements, management makes various assumptions, judgments and estimates to determine the reported amount of assets, liabilities, revenue and expenses, and in the disclosures of commitments and contingencies. Changes in these assumptions, judgments and estimates will occur as a result of the passage of time and the occurrence of future events and, accordingly, actual results could differ from amounts initially established.

The more significant areas requiring the use of assumptions, judgments and estimates relate to volumes of natural gas and oil reserves used in calculating depletion, the amount of expected future cash flows used in determining possible impairments of oil and gas properties and the amount of future capital costs used in such calculations. Assumptions, judgments and estimates also are required in determining future abandonment obligations, impairments of undeveloped properties, valuing deferred tax assets and estimating fair values of derivative instruments.

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. If an exploratory well does not find proved reserves, 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 significant exploration and development projects that require greater than six months to be readied for their intended use. Until the third quarter of 2006, the Company had not capitalized any interest expense. The weighted average interest rate used to capitalize interest for the current year was 7.1 percent, including interest and commitment fees paid on the unused portion of the credit facility and amortization of deferred financing costs. The Company capitalized interest costs of $1.0 million for the year ended December 31, 2006.

Other exploration costs, including 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.

Unevaluated properties 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 until all costs are recovered.

Materials and supplies consist primarily of tubular goods and well equipment used in future drilling operations or repair operations and are carried at the lower of cost or market, on a first-in, first-out basis.

The following table sets forth the net capitalized costs and associated accumulated depreciation, depletion and amortization, including impairments, relating to the Company's natural gas and oil producing activities (in thousands), including net capitalized costs associated with properties held for sale of $57.3 million in total proved properties, which is net of $11.0 million of accumulated depreciation, depletion, amortization and impairment, and $18.2 million in total unevaluated properties (see Note 4 for further information on properties held for sale):

	As of December 31,	
	2005	2006
Proved properties	$ 286,503	$ 346,619
Wells and related equipment and facilities	445,943	736,007
Support equipment and facilities	64,969	86,932
Materials and supplies	7,006	2,258
Total proved oil and gas properties	804,421	1,171,816
Accumulated depreciation, depletion, amortization and impairment	(234,713)	(363,587)
Total proved oil and gas properties, net	$ 569,708	$ 808,229
Unevaluated properties	$ 93,145	$ 139,689
Wells and equipment in progress	75,139	81,473
Total unevaluated oil and gas properties, excluded from amortization	$ 168,284	$ 221,162

Net changes in capitalized exploratory well costs for the years ended December 31, 2004, 2005 and 2006 are reflected in the following table (in thousands):

	Year Ended December 31,		
	2004	2005	2006
		(in thousands)	
Beginning of period	$ 310	$ 19,940	$ 61,530
Additions to capitalized exploratory well costs pending the determination of proved reserves	85,445	209,847	211,290
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(42,788)	(157,158)	(192,337)
Exploratory well costs charged to dry hole costs and abandonment expense	(23,027)	(11,099)	(10,887)
End of period	$ 19,940	$ 61,530	$ 69,596

The following table provides an aging of capitalized exploratory well costs based on the date the drilling was completed and the number of gross wells for which exploratory well costs have been capitalized for a period greater than one year since the completion of drilling (dollars expressed in thousands):

	Year Ended December 31,		
	2004	2005	2006
	(in thousands)		
Capitalized exploratory well costs that have been capitalized for a period of one year or less	$19,940	$58,113	$48,417
Capitalized exploratory well costs that have been capitalized for a period greater than one year	—	3,417	21,179
End of period balance	$19,940	$61,530	$69,596
Number of exploratory wells that have costs capitalized for a period greater than one year	—	24	173

As of December 31, 2006, exploratory well costs that have been capitalized for a period greater than one year since the completion of drilling amounted to $21.2 million. The majority of our exploratory wells that have been capitalized for a period greater than one year are located in the Powder River Basin. In this basin, we drill wells into various coal seams. In order to produce gas from the coal seams, a period of dewatering lasting from a few to twenty four months, or in some cases longer, is required prior to obtaining sufficient gas production to justify capital expenditures for compression and gathering and to classify the reserves as proved.

In addition to our wells in the Powder River Basin, the Company had one well that has been capitalized for greater than one year in the Wind River Basin. It cannot be completed until the approval of the Bureau of Land Management is granted for the right of way to build a gathering line to an existing gas pipeline.

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, recent sales prices of comparable properties, 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.

During the years ended December 31, 2004, 2005 and 2006, the Company recognized non-cash impairment charges of $0.5 million, $42.7 million and $1.2 million, respectively, included within impairment, dry hole costs and abandonment expense. The impairment expense during 2005 is comprised of a $29.5 million impairment charge in the Cooper Reservoir field, $11.3 million impairment charge in the Talon field and $1.9 million impairment charge in the East Madden field. We undertook a drilling program in Cooper Reservoir in 2003 and 2004 with the expectation of a specific economic reserve level. Actual reserve levels were less than our expectations which led to an impairment in the field in 2005. The impairments in the Talon and East Madden fields were the result of unsuccessful exploration programs. The impairment expense during 2006 is a $1.2 million impairment charge to our Cedar Camp and Tumbleweed properties within the Uinta Basin. These properties were held for sale as of September 30, 2006 and were subsequently sold during the fourth quarter of 2006. The carrying amount of these properties was adjusted to fair value, which may be determined based upon recent sales prices of comparable properties or the present value of future cash flows, net of operating and development costs, discounted at various rates consistent with current market conditions at which similar types of properties are being traded.

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, which are 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 lesser of five years or 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 of three to ten 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.

Accounts Payable and Accrued Liabilities. Accounts payable and accrued expenses are comprised of the following:

	As of December 31,	
	2005	2006
Accrued drilling and facility costs	$36,070	$39,570
Accrued lease operating and gathering and transportation expenses	3,037	4,308
Accrued general and administrative expenses	5,013	6,002
Trade payables	8,411	11,923
Other	5,582	7,716
Total accounts payable and accrued liabilities	$58,113	$69,519

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, 2005 and 2006, the Company has not accrued for nor been fined or cited for any environmental violations that 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, 2005 and 2006 were not significant.

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

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 also enters into derivative contracts to mitigate the risk of interest rate 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 (loss) 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 or interest rate fluctuations. 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 or modification of the Company's credit facility are capitalized and amortized over the life of the facility.

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 liabilities are 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.

Asset Retirement Obligations. The Company accounts for its asset retirement obligations in accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations*. 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.

Repurchases and Retirements of Capital Stock. The Company records treasury stock contributions at cost. Upon retirement of treasury shares, the excess of purchase or contribution cost over associated common stock par value is allocated to additional paid-in capital. The allocation to additional paid-in capital is based on the per-share amount of capital in excess of par value for all shares.

Stock-Based Compensation. In December 2004, the Financial Accounting Standards Board ("FASB") issued SFAS No. 123 (revised 2004) *Share-Based Payment* ("SFAS No. 123(R)"), 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. 123(R) 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. 123(R), 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, the date that is defined by SFAS No. 123(R) as the date we became a public company as a result of making a filing with a regulatory agency in preparation for the sale of equity securities in a public market), we adopted SFAS No. 123(R) using the prospective transition method. Under the prospective transition method, we continue to account for awards granted prior to becoming a public company using the minimum value method described under SFAS No. 123. Accordingly, zero compensation expense was recorded upon adoption of SFAS No. 123(R) for those awards. Additionally, the calculated fair value of those awards using the minimum value method is not comparable to those options granted subsequent to April 16, 2004, for which a fair-value-based method was used.

For awards granted after we were a public company (those granted subsequent to April 16, 2004), we adopted SFAS No. 123(R) using the modified prospective application effective October 1, 2004, whereby as of that date we began applying the provisions of SFAS No. 123(R) to new awards and to awards modified, repurchased, or cancelled on or after October 1, 2004. For awards granted after April 16, 2004 and before 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 granted and for which the requisite service had not yet been rendered.

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. 123(R) on October 1, 2004:

	Year Ended December 31, 2004
	(in thousands, except per share amounts)
Net loss, as reported	$ (5,266)
Add stock-based compensation included in reported net loss, net of related tax effects	3,003
Deduct stock-based compensation expense determined under fair value method, net of related tax effects	(3,016)
Pro forma net loss	(5,279)
Less cumulative and deemed dividends on preferred stock	(54,976)
Pro forma loss attributable to common stock	$(60,255)
Basic loss per share:	
As reported	$ (15.40)
Pro forma	$ (15.40)
Diluted loss per share:	
As reported	$ (15.40)
Pro forma	$ (15.40)

The Company continues to account for certain stock options under the original provisions of APB Opinion No. 25 because those options were issued prior to April 16, 2004, when we were considered a nonpublic entity as defined by SFAS No. 123(R). Because 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. 123(R).

During the year ended December 31, 2006, the Company granted options to purchase 802,370 shares of common stock with a weighted average exercise price of $31.87 per share and 286,485 nonvested equity shares of common stock. Included within general and administrative expense is non-cash stock based compensation related to option and nonvested equity share awards of $3.0 million, $3.2 million and $6.5 million for the years ended December 31, 2004, 2005 and 2006, respectively. See Note 10 for additional disclosures about stock-based compensation.

Earnings Per Share. In connection with our IPO in December 2004, a common stock reverse split of 1-for-4.658 was effected. All share and per share amounts for periods prior to December 2004 reflect the reverse split.

Basic net income (loss) per common share of stock is calculated by dividing net income (loss) attributable to common stock by the weighted-average of vested common shares outstanding during each period. Diluted net income (loss) attributable to common shareholders is calculated using the treasury stock method, which also considers the impact to net income and common shares for the potential dilution from stock options and nonvested equity shares of common stock.

Net income (loss) attributable to common stock is calculated by reducing net income (loss) by dividends earned on preferred securities. For the year ended December 31, 2004, 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 year ended December 31, 2004, as their inclusion would have been anti-dilutive. For the years ended December 31, 2005 and 2006, 118,700 and 557,585 shares, respectively, attributable to the assumed exercise of outstanding options were excluded from the calculation of diluted EPS because the effect was antidilutive.

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. 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 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. 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 income (loss) attributable to common stock because the contingency related to the conversion has been resolved due to the completion of the initial public offering.

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

	Year Ended December 31,		
	2004	2005	2006
	(in thousands except per share amounts)		
Net income (loss)	$ (5,266)	$ 23,805	$ 62,011
Less cumulative dividends on preferred stock	(18,633)	n/a	n/a
Less deemed dividends on preferred stock	(36,343)	n/a	n/a
Net income (loss) to be allocated	(60,242)	23,805	62,011
Less allocation of undistributed earnings to participating preferred stock	—	—	—
Net income (loss) attributable to common stock	(60,242)	23,805	62,011
Adjustments to net income for dilution	n/a	—	—
Net income (loss) adjusted for the effect of dilution	$(60,242)	$ 23,805	$ 62,011
Basic weighted-average common shares outstanding in period	3,912.3	43,238.3	43,694.8
Add dilutive effects of stock options and nonvested equity shares of common stock	—	201.3	574.6
Diluted weighted-average common shares outstanding in period	3,912.3	43,439.6	44,269.4
Basic income (loss) per common share	$ (15.40)	$ 0.55	$ 1.42
Diluted income (loss) per common share	$ (15.40)	$ 0.55	$ 1.40

The weighted-average number of common shares outstanding used in the income (loss) per share calculation is computed pursuant to SFAS No. 128. The weighted-average common shares outstanding for the year ended December 31, 2004 do 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 upon the completion of our initial public offering 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.

New Accounting Pronouncements. In June 2005, the FASB issued SFAS No. 154, *Accounting Changes and Error Corrections,* which replaces APB Opinion No. 20, *Accounting Changes,* and SFAS No. 3, *Reporting Accounting Changes in Interim Financial Statements.* SFAS No. 154 changes the requirements for the accounting and reporting of a change in accounting principle. APB Opinion No. 20 previously required that most voluntary changes in an accounting principle be recognized by including the cumulative effect of the new accounting principle in net income of the period of the change. SFAS No. 154 now requires retrospective application of changes in an accounting principle to prior period financial statements, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. The Statement was effective for fiscal years beginning after December 15, 2005, and its adoption did not have an impact on our financial statements.

In October 2005, the FASB issued FASB Staff Position ("FSP") Financial Accounting Standards ("FAS") No. 13-1, *Accounting for Rental Costs Incurred during a Construction Period,* which was effective for our Company as of January 1, 2006. This Position requires that rental costs associated with ground or building operating leases that are incurred during a construction period be recognized as rental expense. The adoption of this FSP did not have an impact on our financial statements.

In July 2006, the FASB issued FASB Interpretation ("FIN") No. 48, *Accounting for Uncertainty in Income Taxes.* FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes.* FIN 48 also prescribes a recognition threshold and measurement standard for the financial statement recognition and measurement of an income tax position taken or expected to be taken in a tax return. In addition, FIN 48 provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The Company presently recognizes income tax positions based on management's estimate of whether it is reasonably possible that a liability has been incurred for unrecognized income tax benefits by applying FASB Statement No. 5, Accounting for Contingencies. The provisions of FIN 48 will be effective for the Company on January 1, 2007 and are to be applied to all tax positions upon initial application of this standard. Only tax positions that meet the more-likely-than-not recognition threshold at the effective date may be recognized or continue to be recognized upon adoption. The cumulative effect of applying the provisions of FIN 48 will be reported as an adjustment to the opening balance of retained earnings for the fiscal year of adoption. The Company has not yet determined the potential financial statement impact of adopting FIN 48.

In September 2006, the SEC issued Staff Accounting Bulletin ("SAB") No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements.* SAB 108 provides guidance on the consideration of effects of the prior year misstatements in quantifying current year misstatements for the purpose of a materiality assessment. The SEC Staff believes registrants must quantify errors using both a balance sheet and income statement approach and evaluate whether either approach results in quantifying a misstatement that, when all relevant quantitative and qualitative factors are considered, is material. SAB 108 was effective for the Company as of December 31, 2006, and the adoption did not have an impact on the Company's financial statements.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements.* SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosure requirements regarding fair value measurement. Where applicable, this Statement simplifies and codifies fair value related guidance previously issued within GAAP. Although this Statement does not require any new fair value measurements, its application may, for some entities, change current practice. SFAS No. 157 will be effective for the Company beginning January 1, 2008. The adoption of SFAS No. 157 is not expected to have a material impact on our financial statements.

3. *Supplemental Disclosures of Cash Flow Information:*

Supplemental cash flow information is as follows:

	Year Ended December 31,		
	2004	2005	2006
		(in thousands)	
Cash paid for interest	$5,362	$ 1,903	$10,593
Cash paid for income taxes	—	—	500
Supplemental disclosures of noncash investing and financing activities:			
Exchange of oil and gas properties for equipment and other properties	—	—	9,304
Assumption of debt and deferred tax liability—CH4 acquisition	—	—	43,298
Preferred stock issued for payment of oil and gas properties	322	—	—
Preferred stock returned in settlement to terminate an exploration agreement	(500)	—	—
Conversion of convertible note payable into Series A convertible preferred stock	1,900	—	—
Changes in current assets and liabilities that are reflected in investing activities	2,099	17,889	6,818
Net change in asset retirement obligations	7,153	10,854	6,612
Treasury stock acquired for employee stock option exercises	—	5,180	5,059
Retirement of treasury stock	—	—	10,239

4. Acquisitions, Disposition, and Property Held for Sale

Acquisitions

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, 2004:

	Year Ended December 31, 2004	
	As Reported	**Pro Forma**
	(in thousands)	
Revenue	$169,980	$182,271
Direct operating expenses	(40,647)	(42,489)
Revenues in excess of direct operating expenses	129,333	139,782
Net Loss	$ (5,266)	$ (4,049)
Basic and Diluted Net Loss Per Common Share	$ (15.40)	$ (15.09)

On May 8, 2006, the Company acquired 100% of the outstanding stock of CH4 Corporation, a Delaware corporation ("CH4"), for $74.2 million in cash and agreed to pay $6.5 million of indebtedness of CH4. The acquisition was funded with borrowings under the Company's credit facility. The primary assets of CH4 consisted of approximately 84,300 gross (52,000 net) acres of oil and gas leasehold interests of coal bed methane properties in the Powder River Basin of Wyoming and an estimated 11.0 Bcfe of proved reserves.

The CH4 acquisition was recorded using the purchase method of accounting, and the results of operations from the acquisition are included with the results of the Company from the date of closing. The total purchase price of the transaction was allocated preliminarily to the assets acquired and the liabilities assumed based on fair values at the acquisition date. The table below summarizes the allocation, which has been revised from the initial allocation based on updated information (in thousands):

Purchase Price:	
Cash paid, net of cash received	$ 72,547
Debt assumed	6,495
Total	$ 79,042
Allocation of Purchase Price:	
Working capital	$ (412)
Proved oil and gas properties	40,582
Unevaluated oil and gas properties	76,190
Other non-current assets	122
Deferred income taxes	(36,803)
Asset retirement obligation	(637)
Total	$ 79,042

Pro forma financial information is not provided, as the CH4 acquisition was not considered a material business combination to the Company, and the results of operations from those properties are insignificant. Results of operations from the CH4 properties acquired are included in the Company's financial statements beginning May 8, 2006.

Dispositions

In August 2006, the Company completed the sale of approximately 17,000 net acres of certain coalbed methane properties that were acquired with the CH4 acquisition. Proceeds from the sale were $30.7 million and a loss of $0.1 million was recorded due to various purchase price adjustments incurred in the normal course of business.

In December 2006, the Company completed the sale of the Cedar Camp and Tumbleweed properties, within the Uinta Basin, which were previously classified as held for sale at September 30, 2006. Total proceeds from the sale were $3.8 million, which resulted in a gain of $0.1 million, which is included in other operating revenues in the Consolidated Statement of Operations.

The Company also entered into joint exploration agreements and completed other property sales in the Powder River, Paradox, Williston, Wind River, Big Horn, Montana Overthrust, DJ, and Uinta Basins resulting in gains recognized of $30.5 million for the year ended December 31, 2006, which is included in other operating revenues in the Consolidated Statement of Operations. Under EITF 03-13, *Applying the Conditions in Paragraph 42 of FASB Statement No. 144 in Determining Whether to Report Discontinued Operations*, we determined that these sales did not qualify for discontinued operations reporting.

Property Held for Sale

Assets are classified as held for sale when the Company commits to a plan to sell the assets and completion of the sale is probable and expected to occur within one year. Upon classification as held-for-sale, long-lived assets are no longer depreciated or depleted and a loss is recognized, if any, based upon the excess of carrying value over fair value less costs to sell. Previous losses may be reversed up to the original carrying value as estimates are revised; however, gains are recognized only upon disposition.

During 2006, the Board of Directors acknowledged management's plan to sell the Company's oil and gas properties in the Williston Basin. In addition, the Company also decided to divest its Tri-State exploration project in the DJ Basin. In accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, these properties are carried at the lower of historical cost or fair value less cost to sell and were reclassified to assets held for sale on the Consolidated Balance Sheet. Any liabilities related to those properties were also reclassified to liabilities associated with assets held for sale on the Consolidated Balance Sheet. Under EITF 03-13, we determined that these sales do not qualify for discontinued operations reporting.

The following table presents the assets and liabilities associated with the oil and gas properties held for sale in the Williston and DJ Basins as of December 31, 2006 (in thousands):

Proved oil and gas properties	$ 57,280
Unevaluated oil and gas properties	18,216
Noncurrent liabilities	3,374

5. Note Payable to Bank

On March 17, 2006, the Company amended its credit facility (the "Credit Facility"). The Credit Facility has a face value of $400.0 million, expandable up to $600.0 million, and had an initial borrowing base of $280.0 million. Based upon 2006 mid-year reserves, the borrowing base was increased to $310.0 million on October 6, 2006. Future borrowing bases will be computed based on proved natural gas and oil reserves. The Credit Facility matures on March 17, 2011 and bears interest, based on the borrowing base usage, at the applicable London Interbank Offered Rate, ("LIBOR") plus applicable margins ranging from 1.0% to 1.75%, 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 0.25%. The Company pays commitment fees ranging from 0.25% to 0.375% of the unused borrowing base. This facility is secured by natural gas and oil properties representing at least 80% of the value of the Company's proved reserves and the pledge of all of the stock of our subsidiaries.

As of December 31, 2006, borrowings outstanding under the Credit Facility totaled $188.0 million. The Amended Credit Facility also contains certain financial covenants. We have complied with all financial covenants for all periods.

6. Asset Retirement Obligations

The Company accounts for its asset retirement obligations in accordance with SFAS No. 143. This statement generally applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset.

A reconciliation of the Company's asset retirement obligations is as follows, which includes $3.4 million associated with assets held for sale:

	Year Ended December 31,		
	2004	2005	2006
	(in thousands)		
Beginning of period	$ 4,297	$11,806	$23,733
Liabilities incurred	6,996	2,429	3,433
Liabilities settled	(848)	(203)	(1,586)
Accretion expense	397	1,276	2,593
Revisions to estimate	964	8,425	4,425
End of period	$11,806	$23,733	$32,598

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 Credit Facility, as discussed in Note 5, approximates the fair value due to its floating rate structure. The Company's derivatives are marked to market with changes in fair value being recorded in other comprehensive income.

Oil and Gas Commodity Hedges

The Company periodically uses derivative financial instruments to achieve a more predictable cash flow from its natural gas and oil production by reducing its exposure to price fluctuations. We have entered into commodity swap and collar contracts to fix the floor and ceiling prices we receive for a portion of our natural gas and oil production. Our natural gas and oil derivative financial instruments have been designated as cash flow hedges in accordance with SFAS No. 133.

The Company was a party to various swap and collar contracts for natural gas based on Northwest Pipeline Rocky Mountains ("NORRM") and Colorado Interstate Gas Rocky Mountains ("CIGRM") indexes during the years ended December 31, 2005 and 2006. As a result, the Company recognized a reduction of natural gas production revenues related to these contracts of $20.7 million in the year ended December 31, 2005 and an increase of $22.2 million in the year ended December 31, 2006. The Company also was a party to various collar contracts for oil based on a West Texas Intermediate ("WTI") index recognizing a reduction to oil production revenues related to these contracts of $3.7 million and $4.1 million in the years ended December 31, 2005 and 2006, respectively. As the underlying prices in the Company's hedge contracts were consistent with the indices used to sell its natural gas and oil, no ineffectiveness was recognized related to its hedge contracts for the years ended December 31, 2005 and 2006.

At February 16, 2007, the Company had the following swap contracts and cashless collars (purchased put options and written call options) in order to hedge a portion of our 2007 and 2008 natural gas and oil production. The cashless collars are used to establish floor and ceiling prices on anticipated future natural gas production.

Product	Deliveries Per Day	Quantity Type	Weighted Average Floor Pricing	Weighted Average Ceiling Pricing	Weighted Average Fixed Price	Index Price (1)	Contract Period
Cashless Collars:							
Natural gas	15,000	MMBtu	$ 7.50	$12.25	n/a	CIGRM	11/1/2006 – 3/31/2007
Natural gas	64,000	MMBtu	$ 6.07	$ 9.61	n/a	CIGRM	1/1/2007 – 12/31/2007
Oil	800	Bbls	$55.00	$79.85	n/a	WTI	1/1/2007 – 12/31/2007
Natural gas	35,000	MMBtu	$ 6.50	$10.00	n/a	CIGRM	1/1/2008 – 12/31/2008
Oil	500	Bbls	$70.00	$80.15	n/a	WTI	1/1/2008 – 12/31/2008
Swap Contracts:							
Natural gas	10,000	MMBtu	n/a	n/a	$6.50	CIGRM	2/1/2007 – 2/28/2007
Natural gas	5,000	MMBtu	n/a	n/a	$5.21	CIGRM	2/1/2007 – 10/31/2007
Natural gas	20,000	MMBtu	n/a	n/a	$6.44	CIGRM	3/1/2007 – 3/31/2007
Natural gas	45,000	MMBtu	n/a	n/a	$5.47	CIGRM	4/1/2007 – 10/31/2007
Natural gas	55,000	MMBtu	n/a	n/a	$6.90	CIGRM	11/1/2007 – 3/31/2008
Natural gas	10,000	MMBtu	n/a	n/a	$6.75	CIGRM	1/1/2008 – 12/31/2008
Natural gas	5,000	MMBtu	n/a	n/a	$6.30	CIGRM	4/1/2008 – 10/31/2008

(1) CIGRM refers to Colorado Interstate Gas 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.

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 noncurrent assets in the Company's Consolidated Balance Sheets.

At December 31, 2006, the estimated fair value of contracts designated and qualifying as cash flow hedges under SFAS No. 133 was a net asset of $46.7 million. The Company will reclassify the appropriate amount to gains or losses included in natural gas and oil production operating revenues as the hedged production quantity is produced. Based on current projected market prices, the net amount of existing unrealized after-tax income as of December 31, 2006 to be reclassified from accumulated other comprehensive income to net income in the next 12 months would be approximately $19.7 million. The Company anticipates that all originally forecasted transactions will occur by the end of the originally specified time periods.

Interest Rate Derivative Contracts

In December 2006, the Company entered into two interest rate derivative contracts to manage the Company's exposure to changes in interest rates. The first contract was a floating-to-fixed interest rate swap for a notional amount of $10.0 million and the second was a floating-to-fixed interest rate collar for a notional amount of $10.0 million, both to terminate on December 12, 2009. The Company's interest rate derivative instruments have been designated as cash flow hedges in accordance with SFAS No. 133. The derivatives were structured to mirror the critical terms of the hedged debt instruments; therefore, no ineffectiveness has been recorded in earnings.

Under the swap, the Company will make payments to (or receive payments from) the contract counterparty when the variable rate of one-month LIBOR falls below or exceeds the fixed rate of 4.70%. Under the collar, the Company will make payments to (or receive payments from) the contract counterparty when the variable rate falls below the floor rate of 4.50% or exceeds the ceiling rate of 4.95%. The payment dates of both the swap and the collar match exactly with the interest payment dates of the corresponding portion of our outstanding line of credit.

Since the Company did not enter into interest rate derivative contracts until December 2006, there were no settlement payments received or paid for the year ending December 31, 2006. Payments and receipts in future periods will be included in interest expense. The Company anticipates that all originally forecasted transactions will occur by the end of the originally specified time periods, and based on current projected interest rates, the net amount of existing unrealized after-tax income as of December 31, 2006 to be reclassified from accumulated other comprehensive income to net income in the next 12 months would be approximately $0.1 million. At December 31, 2006, the estimated fair value of the interest rate derivatives was a net asset of $0.1 million.

8. Income Taxes

The expense (benefit) for income taxes consists of the following:

	Year Ended December 31,		
	2004	2005	2006
		(in thousands)	
Current			
Federal	$ —	$ —	$ 460
State	—	—	34
Deferred:			
Federal	$(688)	$14,629	$36,353
State	(187)	593	2,278
Total	$(875)	$15,222	$39,125

Income tax expense (benefit) differed from the amounts computed by applying the U.S. federal income tax rate of 35% to pretax income (loss) from continuing operations as a result of the following:

	Year Ended December 31,		
	2004	2005	2006
		(in thousands)	
Income tax expense (benefit) at the federal statutory rate	$(2,088)	$13,659	$35,392
State income taxes, net of federal tax effect	(187)	593	2,278
Non-deductible stock-based compensation	1,392	797	942
Other, net	8	173	513
Income tax expense (benefit)	$ (875)	$15,222	$39,125

Income tax expense (benefit) for the years ended December 31, 2004, 2005 and 2006 differs from the amounts that would be provided by applying the U.S. federal income tax rate to income (loss) before income taxes principally due to stock-based compensation not deductible for income tax purposes and other permanent differences.

The tax effects of temporary differences that give rise to significant components of the deferred tax assets and deferred tax liabilities at December 31, 2005 and 2006 are presented below:

	December 31,	
	2005	2006
	(in thousands)	
Current:		
Deferred tax assets (liabilities):		
Derivative instruments	$ 10,751	$ (14,233)
Other accrued expenses	—	589
Prepaid expenses	(273)	(317)
Total current deferred tax assets (liabilities)	$ 10,478	$ (13,961)
Long-term:		
Deferred tax assets:		
Net operating loss carryforward	$ 30,323	$ 28,434
Start-up/organization costs, net	229	33
Long-term derivative instruments	2,587	—
Stock-based compensation	324	1,395
Deferred rent	248	328
Minimum tax credit carryforward	—	459
Other	56	100
Less valuation allowance	—	(1,635)
Total long-term deferred tax assets	33,767	29,114
Deferred tax liabilities:		
Oil and gas properties	(41,534)	(115,641)
Long-term derivative instruments	—	(3,203)
Other	(193)	—
Total long-term deferred tax liabilities	(41,727)	(118,844)
Net long-term deferred tax liabilities	$ (7,960)	$ (89,730)

At December 31, 2006, the Company had approximately $77.0 million of federal tax net operating loss carryforwards which expire through 2025. The Company has placed a valuation allowance on the net operating loss carryforward acquired in the CH4 acquisition. This loss carryforward will expire in 2024. The Company has a federal alternative minimum tax ("AMT") credit carryforward of $0.5 million, which has no expiration date.

At December 31, 2006, the Company's balance sheet reflected net deferred tax liabilities of $103.7 million, of which $17.4 million pertains to the tax effects of derivative instruments reflected in other comprehensive income.

9. Stockholders' Equity

On December 9, 2004, the Company priced its shares to be issued in its initial public offering and began trading on the New York Stock Exchange the following day under the ticker symbol "BBG". Immediately prior to the initial public offering, 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 initial public offering, 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 initial public offering. The Company received

$347.3 million in net proceeds after deducting underwriters' fees and related offering expenses. The proceeds received from the initial public offering 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, 2005, 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 initial public offering, 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 initial public offering.

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. The Series A Junior Participating Preferred Stock will be issued pursuant to our shareholder rights plan if a stockholder acquires shares in excess of the thresholds set forth in the plan. The Series A Junior Participating Preferred Stock 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 initial public offering, Series A convertible preferred stock was eliminated. Prior to the Company's initial public offering, 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 initial public offering, 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 initial public offering.

Series B Preferred Stock. Following the Company's initial public offering, Series B convertible preferred stock was eliminated. Prior to the Company's initial public offering, 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 initial public offering, 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 in the 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 $19.3 million and $11.3 million related to the 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 initial public offering 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 initial public offering price related to the liquidation preference being converted less the underwriters' fees. Total deemed dividends recorded at the initial public offering 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.

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 initial public offering 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 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, 100% of the shares were dollar vested and 1,778,710 were time vested as of December 31, 2005. As of December 31, 2006 all shares were dollar and time vested.

Treasury Stock. The Company may occasionally acquire treasury stock in connection with the vesting and exercise of share-based awards, which is recorded at cost. As of December 31, 2006, all treasury stock held by the Company was retired.

The following table reflects the activity in the Company's common, preferred, and treasury stock. All common stock amounts reflect the reverse split that occurred in conjunction with our initial public offering.

	Year Ended December 31,		
	2004	2005	2006
Series A Preferred Stock Outstanding:			
Shares at beginning of period	6,258,994	—	—
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 initial public offering	(6,594,725)	—	—
Shares at end of period	—	—	—
Series B Preferred Stock Outstanding:			
Shares at beginning of period	45,145,700	—	—
Shares issued under Stock Purchase Agreement dated March 28, 2002	6,600,000	—	—
Shares issued for cash under Bill Barrett Corporation Employee Restricted Stock Purchase Plan	145,918	—	—
Shares issued for mineral leasehold interests	59,800	—	—
Shares converted into common stock immediately prior to initial public offering	(51,951,418)	—	—
Shares at end of period	—	—	—
Common Stock Outstanding:			
Shares at beginning of period	1,857,477	43,323,270	43,695,286
Exercise of common stock options	128,135	366,664	462,227
Shares issued for 401(k) plan	—	—	16,883
Shares issued for nonvested equity shares of common stock	—	5,352	252,817
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 initial public offering	14,950,000	—	—
Shares retired	—	—	(285,760)
Shares at end of period	43,323,270	43,695,286	44,141,453
Treasury Stock:			
Shares at beginning of period	—	—	124,024
Treasury stock acquired	—	124,024	161,736
Treasury stock retired	—	—	(285,760)
Shares at end of period	—	124,024	—

Accumulated Other Comprehensive Income (Loss). The Company follows the provisions of SFAS No. 130, *Reporting Comprehensive Income*, which establishes standards for reporting comprehensive income (loss). The components of accumulated other comprehensive income (loss) and related tax effects for the years ended December 31, 2004, 2005 and 2006 were as follows:

	Gross	Tax Effect	Net of Tax
		(in thousands)	
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 income	6,986	(2,585)	4,401
Accumulated other comprehensive loss—December 31, 2004	(5,665)	2,096	(3,569)
Change in fair value of hedges	(53,490)	19,792	(33,698)
Reclassification adjustment for realized losses on hedges included in net income	23,105	(8,549)	14,556
Accumulated other comprehensive loss—December 31, 2005	$(36,050)	$ 13,339	$(22,711)
Change in fair value of hedges	96,882	(35,999)	60,883
Reclassification adjustment for realized gains on hedges included in net income	(14,025)	5,224	(8,801)
Accumulated other comprehensive income—December 31, 2006	$ 46,807	$(17,436)	$ 29,371

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 is included in 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.

In accordance with FIN No. 28, the remaining stock-based compensation expense was recognized ratably over the remaining time vesting service period, January 31, 2006, at which time the shares were fully vested. Based on the fair value vested for these common stock issuances, the Company recorded $2.0 million, $0.5 million, and $0.04 million of stock-based compensation expense in the years ended December 31, 2004, 2005, and 2006 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.

A summary of activity for the restricted common stock as of December 31, 2006, and changes during the year then ended, is presented below:

	Shares	Weighted Average Fair Value
Nonvested at January 1, 2006	21,837	$1.75
Granted	—	N/A
Vested	(21,837)	$1.75
Forfeited or expired	—	N/A
Nonvested at December 31, 2006	—	N/A

Stock Options & Nonvested Equity Shares. 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 initial public offering, 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 initial public offering 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 initial public offering 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 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 four 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 granted thus far under the 2004 Incentive Plan generally expire seven years from the date of grant and vest 25% on the first four anniversaries of the date of grant. 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 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 or issue treasury shares to settle any such exercises. For years ended December 31, 2004, 2005 and 2006, we used no cash to repurchase any stock related to any option exercises.

In accordance with SFAS No. 123(R), the fair value of each share-based award under all our plans is estimated on the date of grant using a Black-Scholes 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 2.7 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.

	Year Ended December 31,		
	2004	**2005**	**2006**
Weighted Average Volatility	37%	39%	36%
Expected Dividend Yield	0%	0%	0%
Weighted Average Expected Term (in years)	3.0	2.9	2.7
Weighted Average Risk-free Rate	3.1%	3.7%	4.3%

A summary of share-based option activity under all our plans as of December 31, 2006, 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, 2006	2,334,598	$23.51		
Granted	802,370	31.87		
Exercised	(462,227)	20.86		
Forfeited or expired	(245,672)	28.10		
Outstanding at December 31, 2006	2,429,069	$26.31	5.29	$6,587,344
Vested, or expected to vest, at December 31, 2006	2,376,982	$26.25	5.27	6,519,423
Exercisable at December 31, 2006	1,126,906	$23.14	4.57	$4,889,325

The per share weighted-average grant-date fair value of awards granted for the years ended December 31, 2004, 2005 and 2006 was $7.11, $9.54 and $7.26, respectively, and the total intrinsic value of awards exercised during the same periods was $1.5 million, $8.6 million and $4.5 million, respectively. Related to stock option exercises, we received less than $0.1 million for the year ended December 31, 2004 and $3.0 and $4.9 million for the years ended December 31, 2005 and 2006, respectively. In addition, no cash was used to settle stock option exercises for the years ended December 31, 2004, 2005 and 2006.

A summary of the Company's nonvested equity shares of common stock as of December 31, 2006, and changes during the year then ended, is presented below:

	Shares	Weighted-average Grant Date Fair Value
Outstanding at January 1, 2006	4,740	$32.70
Granted	286,485	34.37
Vested	(3,033)	34.27
Forfeited or expired	(33,668)	35.23
Outstanding at December 31, 2006	254,524	$34.22
Vested, or expected to vest, at December 31, 2006	244,343	$34.22
Exercisable at December 31, 2006	—	$ —

We recorded non-cash stock-based compensation related to awards of $3.0 million, $3.2 million, and $6.4 million for the years ended December 31, 2004, 2005 and 2006, respectively. Included in the $3.2 million and $6.4 million of stock-based compensation for the year ended December 31, 2005 and 2006, respectively, is $0.3 and $0.9 million related to the modification of equity awards for certain employees in which their vesting terms were accelerated. None of the stock-based compensation has been capitalized, and the related tax benefit recognized was less than $0.1 million for the year ended December 31, 2004. For the year ended December 31, 2005, the Company recognized a tax benefit of $1.2 million that was charged to stockholder's equity for the exercise of stock options. For the year ended December 31, 2006, the Company did not recognize an excess tax benefit related to the exercise of stock options in accordance with SFAS No. 123(R). As of December 31, 2006, there was $16.8 million of total compensation costs related to nonvested stock option and nonvested equity shares of common stock grants that is expected to be recognized over a weighted-average period of 3.1 years.

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. Through December 31, 2005, the Company matched 100% of the employee contribution, up to 4% of the employee's pretax income.

Beginning on January 1, 2006, the Company amended the 401(k) Plan to match 100% of the employee contribution, up to 6% of the employee's pretax income, with 50% of the match made with the Company's common stock. The Company's cash contributions and shares of common stock are fully vested upon the date of match. The Company made matching cash contributions of $0.4 million, $0.6 million, and $0.5 million for the years ended December 31, 2004, 2005 and 2006, respectively, and common stock contributions of $0.5 million for the year ended December 31, 2006.

11. Transactions with Related Parties

A director of the Company until May 2006 is a managing director of a company affiliated with the company which wholly owns the counterparty to a portion of 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 initial public offering.

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 2004, ONEOK Inc. accounted for 37.5% of the Company's oil and gas production revenues. During 2005, ONEOK Inc., Xcel Energy Inc., and OGE Energy Resources Inc. accounted for 20.3%, 10.3%, and 10.0%, respectively, of the Company's oil and gas production revenues. During 2006, Sempra Energy Trading Corporation, Xcel Energy Inc., and ONEOK Inc. accounted for 21.3%, 10.0%, and 9.7%, respectively, 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 and interest rate levels 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

Transportation Demand and Firm Processing Charges. The Company has entered into contracts which provide firm transportation capacity and processing rights on pipeline systems. The remaining terms on these contracts range from 1 to 13 years and require the Company to pay transportation demand and processing charges regardless of the amount of pipeline capacity utilized by the Company. The Company paid $1.7 million and $3.7 million of transportation demand charges for the years ended December 31, 2005 and 2006, respectively. The Company paid $0.7 million of firm processing charges in 2006; there were no firm processing charges paid in 2005. All transportation costs including demand charges and processing charges are included in gathering and transportation expense in the Consolidated Statement of Operations.

Future minimum transportation demand and firm processing charges as of and subsequent to December 31, 2006 are as follows (in thousands):

2007	$ 5,801
2008	15,027
2009	17,353
2010	17,764
2011	23,700
Thereafter	104,420
Total	$184,065

Lease Obligations and Other Commitments. The Company leases office space and certain equipment under non-cancelable operating leases. Office lease expense for the years ended December 31, 2004, 2005 and 2006 was $0.8 million, $0.9 million and $1.4 million, respectively. Additionally, the Company has entered into various long-term agreements for telecommunication service. The Company also has commitments for developing oil and gas properties of $25.6 million and $2.7 million for 2007 and 2008, respectively, which are included in the minimum payment schedule below.

Future minimum annual payments under such leases and agreements as of and subsequent to December 31, 2006 are as follows (in thousands):

	Other Commitments	Office & Equipment Leases
2007	$25,640	$1,625
2008	2,705	1,504
2009	—	1,540
2010	—	1,593
2011	—	450
Thereafter	—	—
Total	$28,345	$6,712

In addition to the commitments above, the Company has commitments for the purchase of facilities and office equipment as of and subsequent to December 31, 2006 for a total of $14.1 million.

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:

	Year Ended December 31,		
	2004	2005	2006
	(in thousands, except amortization data)		
Acquisition costs:			
Unproved properties	$ 73,469	$ 25,689	$126,091
Proved properties	79,440	1,288	33,138
Exploration costs	98,751	218,586	224,189
Development costs	93,304	95,236	114,593
Asset retirement obligation	7,153	10,650	6,272
Total costs incurred	$352,117	$351,449	$504,283
Amortization per Mcfe of production	$ 2.12	$ 2.20	$ 2.60

Supplemental Oil and Gas Reserve Information. The reserve information presented below is based on estimates of net proved reserves as of December 31, 2004, 2005, and 2006 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, including 6,618 MBbls of oil, 2,001 MMcf of gas, and 41,709 MMcfe relating to properties held for sale in the Williston Basin and 18 MMcf of gas and gas equivalent units relating to properties held for sale in the DJ Basin:

	Oil (MBbls)	Gas (MMcf)	Equivalent Units (MMcfe)
Proved reserves:			
Balance, December 31, 2003	3,886	180,874	204,190
Purchases of oil and gas reserves in place	201	48,949	50,155
Extension, discoveries and other additions	1,846	87,098	98,174
Revisions of previous estimates	440	(28,490)	(25,850)
Sales of reserves	(161)	(1,691)	(2,657)
Production	(474)	(28,864)	(31,708)
Balance, December 31, 2004	5,738	257,876	292,304
Purchases of oil and gas reserves in place	5	3,274	3,304
Extension, discoveries and other additions (1)	1,130	96,223	103,004
Revisions of previous estimates (1)	(414)	(14,598)	(17,082)
Sales of reserves (1)	(102)	(517)	(1,130)
Production	(523)	(36,286)	(39,424)
Balance, December 31, 2005	5,834	305,972	340,976
Purchases of oil and gas reserves in place	—	19,529	19,529
Extension, discoveries and other additions	3,063	129,309	147,687
Revisions of previous estimates	252	(23,000)	(21,488)
Sales of reserves	—	(6,152)	(6,152)
Production	(696)	(47,932)	(52,108)
Balance, December 31, 2006	8,453	377,726	428,444
Proved developed reserves:			
December 31, 2004	4,249	153,118	178,612
December 31, 2005	4,283	182,777	208,475
December 31, 2006	5,006	218,902	248,938

(1) In 2006, the Company reclassified 14,362 MMcfe and 601 MMcfe of 2005 proved reserves from "Revisions of previous estimates" to "Extension, discoveries and other additions" and "Sales of Reserves," respectively. "Revisions of previous estimates" decreased by 3,262 MBbls of oil and increased by 4,609 MMcf of gas. "Extension, discoveries and other additions" increased by 3,162 MBbls of oil and decreased by 4,609 MMcf of gas. "Sales of reserves" increased by 100 MBbls of oil. As this is a reclassification between categories within proved reserves, there is no change to ending reserves as of December 31, 2005.

At year end 2004, we revised our proved reserves downward by 32 Bcfe, excluding pricing revisions. The revision was primarily the result of encountering unexpected pressure depletion during infill drilling in the Wind River Basin and greater pressure depletion than expected in two areas in the Powder River Basin. The downward revision in the Wind River Basin in 2004 was 27.6 Bcfe. In this basin, 47.6% of the proved wells forecast in the Wind River basin at year-end 2003 were 25% below forecast at year-end 2004. The reserve variance between the independent reserve engineers and the Company at year-end 2004 for this basin was 6.6 Bcfe with the independent engineers at the lower estimate. The downward revision in the Powder River Basin in 2004 was 7.2 Bcfe. In this basin, 29% of the proved wells forecast at year-end 2003 were 25% below forecast at year-end 2004. The reserve variance between the independent reserve engineers and the Company at year-end 2003 for this basin was 1.7 Bcfe with the independent engineers at the lower estimate.

At year end 2005, we revised our proved reserves downward by 24.7 Bcfe, excluding pricing revisions, primarily as a result of a reduction in proved undeveloped reserves in the Piceance Basin due to the use of completion techniques performed from January through September 2005 that yielded results lower than our expectations at year-end 2004. Completion techniques used in subsequent periods have yielded more favorable results, which are reflected in upward revisions in 2006 reserve estimates in this area. The downward revision in the Piceance Basin in 2005 was 25.6 Bcfe. In this basin, 31% of the proved wells forecast at year-end 2004 were 25% below forecast at year-end 2005. The reserve variance between the independent reserve engineers and the Company at year-end 2004 for this basin was 13 Bcfe with the independent engineer at the lower estimate. The downward revision in the Powder River Basin in 2005 was 9.6 Bcfe. In this basin, 36% of the proved wells forecast at year-end 2004 were 25% below forecast at year-end 2005. The reserve variance between the independent reserve engineers and BBC at year-end 2004 for this basin was 3.8 Bcfe with the independent engineer at the lower estimate. An upward revision of 8.1 Bcfe occurred in the Uinta Basin in the West Tavaputs Field in 2005. In this basin, 31% of the proved wells forecast at year-end 2004 were 25% above forecast at year-end 2005. The reserve variance between the independent reserve engineers and BBC at year-end 2004 was 2.1 Bcfe with the independent engineer at the lower estimate.

During 2005, reviews of proved oil and gas properties in the Wind River Basin indicated a decline in the recoverability of their carrying value and the need for an impairment in the Cooper Reservoir, Talon and East Madden fields in the total amount of $42.7 million. We undertook a drilling program in Cooper Reservoir in 2003 and 2004 with the expectation of a specific economic reserve level. Actual reserve levels were less than our expectations which led to an impairment in the field in 2005. The impairments in the Talon and East Madden fields were the result of unsuccessful exploration programs.

At year-end 2006, we revised our proved reserves upward by 12.4 Bcfe, excluding pricing revisions. This revision was primarily the result of increased performance of wells drilled during the last half of 2005 and the first half of 2006. The pricing revision at year-end 2006 at prices of $4.46 per MMBtu of gas and $61.06 per barrel of oil, relative to year-end 2005 prices of $7.72 per MMBtu and $61.04 per barrel of oil, was downward 33.8 Bcfe. These prices were adjusted by lease for quality, transportation fees and regional price differences.

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 $43.46, $61.04 and $61.06 per Bbl for oil and $5.52, $7.72, and $4.46 per Mmbtu for gas for 2004, 2005, and 2006, respectively. These prices are adjusted for transportation and quality and basis differentials. 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,		
	2004	2005	2006
		(in thousands)	
Future cash inflows	$1,722,369	$2,882,165	$2,201,106
Future production costs	(502,269)	(638,004)	(601,502)
Future development costs	(211,464)	(362,424)	(418,126)
Future income taxes	(223,884)	(487,992)	(168,959)
Future net cash flows	784,752	1,393,745	1,012,519
10% annual discount	(318,643)	(611,267)	(483,233)
Standardized measure of discounted future net cash flows	$ 466,109	$ 782,478	$ 529,286

The present value (at a 10% annual discount) 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% annual 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.

A summary of changes in the standardized measure of discounted future net cash flows is as follows:

	Year Ended December 31,		
	2004	2005	2006
		(in thousands)	
Standardized measure of discounted future net cash flows, beginning of period	$ 404,820	$ 466,109	$ 782,478
Sales of oil and gas, net of production costs and taxes	(137,606)	(243,717)	(253,645)
Extensions, discoveries and improved recovery, less related costs	237,683	303,751	178,726
Quantity revisions	(70,074)	(130,275)	(43,902)
Price revisions	(22,382)	396,299	(474,739)
Net changes in estimated future development costs	9,316	(25,191)	62,574
Accretion of discount	52,082	59,206	104,960
Purchases of reserves in place	83,171	11,260	33,518
Sales of reserves	(4,535)	(1,138)	(9,671)
Changes in production rates (timing) and other	(76,425)	87,349	(44,614)
Net changes in future income taxes	(9,941)	(141,175)	193,601
Standardized measure of discounted future net cash flows, end of period	$ 466,109	$ 782,478	$ 529,286

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, 2005 and 2006.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share data)			
Year ended December 31, 2005:				
Total revenues	$51,906	$ 54,449	$71,237	$111,167
Less: costs and expenses	46,634	79,220	50,291	72,389
Operating income	5,272	(24,771)	20,946	38,778
Income (loss) before income taxes	5,305	(24,765)	20,555	37,932
Net income (loss)	3,054	(15,871)	13,297	23,325
Net income (loss) per common share, basic	0.07	(0.37)	0.31	0.54
Net income (loss) per common share, diluted	0.07	(0.37)	0.30	0.53

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share data)			
Year ended December 31, 2006:				
Total revenues	$97,774	$82,611	$104,412	$90,532
Less: costs and expenses	61,716	67,005	68,835	68,825
Operating income	36,058	15,606	35,577	21,707
Income before income taxes	35,236	13,311	33,074	19,515
Net income	22,134	8,210	20,701	10,966
Net income per common share, basic	0.51	0.19	0.47	0.25
Net income per common share, diluted	0.50	0.19	0.47	0.25

corporate information

CORPORATE OFFICE
1099 Eighteenth Street, Suite 2300
Denver, Colorado 80202
Telephone: 303-293-9100
Fax: 303-291-0420
Internet: www.billbarrettcorp.com

ANNUAL STOCKHOLDERS' MEETING
Our annual stockholders' meeting will be held at 9:30 a.m. (MST) on Wednesday, May 9, 2007 at the Westin Tabor Center Auditorium
1672 Lawrence Street
Denver, Colorado 80202

TRANSFER AGENT
Mellon Investor Services LLC
Ridgefield Park, New Jersey

INDEPENDENT AUDITORS
Deloitte & Touche LLP
Denver, Colorado

INDEPENDENT AND OUTSIDE RESERVOIR ENGINEERS
Ryder Scott Company, L.P.
Denver, Colorado
Netherland Sewell & Associates, Inc.
Dallas, Texas

NON-GAAP MEASURES

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.

The Company calculates organic finding and development cost, or F&D cost, per Mcfe, by dividing (x) costs incurred less asset retirement obligation and less material acquisitions and less certain non-cash capital items less proceeds received for divesting and joint exploration agreement, by (y) reserve additions for the year less reserves acquired for cash, netted against reserves disposed. Consistent with industry practice, future capital expenditures to develop proved undeveloped reserves or capital associated with furniture, fixtures and equipment are not included in costs incurred. The methods the Company uses to calculate its F&D cost may differ significantly from methods used by other companies to compute similar measures. As a result, the Company's F&D cost may not be comparable to similar measures provided by other companies. The Company believes that providing a non-GAAP measure of F&D cost is useful to investors in evaluating the cost, on a per thousand cubic feet of natural gas equivalent basis, to add proved reserves. However, this measure is provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in its financial statements prepared in accordance with GAAP. Due to various factors, including timing differences in the addition of proved reserves and the related costs to develop those reserves, F&D cost do not necessarily reflect precisely the costs associated with particular reserves. As a result of various factors that could materially affect the timing and amounts of future increases in reserves and the timing and amounts of future costs, the Company cannot assure you that its future F&D cost will not differ material from those presented.

For a reconciliation of these non-GAAP measures to financial information prepared in accordance with GAAP, refer to our Current Reports on Form 8-K filed with the Securities and Exchange Commission (SEC).

FORWARD LOOKING STATEMENTS AND OTHER NOTICES

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 Annual Report on Form 10-K for the year ended December 31, 2006.

The SEC permits oil and gas companies, in their filings with the SEC, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. Bill Barrett Corporation may use certain terms in this report and other communications relating to reserves, resources, and production that the SEC's guidelines strictly prohibit the Company from including in filings with the SEC. It is recommended that U.S. investors closely consider the Company's disclosures in the accompanying Annual Report on Form 10-K for the year ended December 31, 2006 filed with the SEC. This document is available through the SEC by calling 1-800-SEC-0330 (U.S.) and on the SEC website at www.sec.gov.

The New York Stock Exchange's Rule 303A.12(a) requires chief executive officers of listed companies to certify that they are not aware of any violations by their company of the exchange's corporate governance listing standards. This annual certification by the chief executive officer of Bill Barrett Corporation has been filed with the New York Stock Exchange. In addition, Bill Barrett Corporation has filed, as exhibits to its most recently filed Form 10-K, the SEC certifications required for the chief executive officer and chief financial officer under Section 302 of the Sarbanes-Oxley Act.

officers

Standing (left to right): **Kevin M. Finnegan**, Vice President–Information Systems, **Duane J. Zavadil**, Vice President–Government and Regulatory Affairs, **Huntington T. Walker**, Senior Vice President–Land, **Joseph N. Jaggers**, Chief Operating Officer, President and Director, **Fredrick J. Barrett**, Chief Executive Officer and Chairman, **Terry R. Barrett**, Senior Vice President Exploration–Northern Division, **Francis B. Barron**, Senior Vice President and General Counsel, **Lynn Boone Henry**, Vice President–Planning and Reserves, **David R. Macosko**, Vice President–Accounting
Sitting: **Wilfred R. (Roy) Roux**, Senior Vice President–Geophysics, **Kurt M. Reinecke**, Senior Vice President Exploration–Southern Division; Not pictured: **Robert W. Howard**, Chief Financial Officer

directors

Fredrick J. Barrett
Chief Executive Officer and Chairman

James M. Fitzgibbons
Director

Randy A. Foutch
Director

Jeffrey A. Harris
Director

Joseph N. Jaggers
Chief Operating Officer and Director

Philippe S.E. Schreiber
Director

Randy Stein
Director

Michael E. Wiley
Director

Design by EnerCom Inc; Photography by: Bill Barrett Corporation employees except where noted

Bill Barrett Corporation

OUR 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

BBG
LISTED
NYSE

END