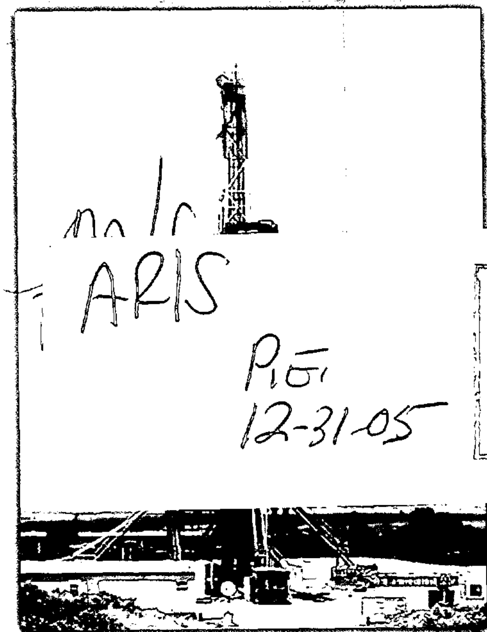
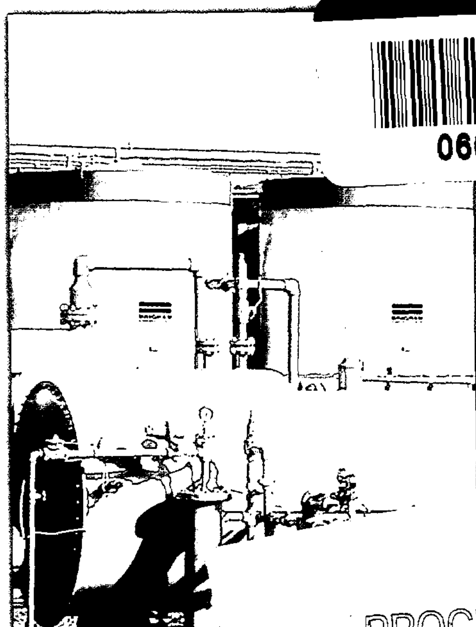
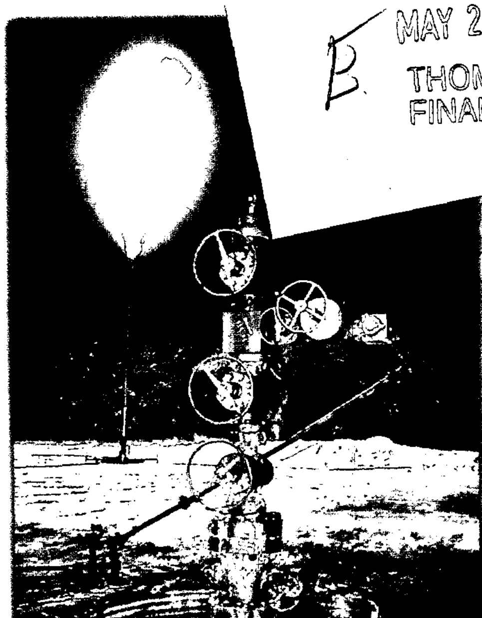






BRIGHAM
Exploration Company

2005 ANNUAL REPORT

CELEBRATING 15 YEARS OF ORGANIC GROWTH

Brigham Exploration Company

CORPORATE OVERVIEW

STRATEGY

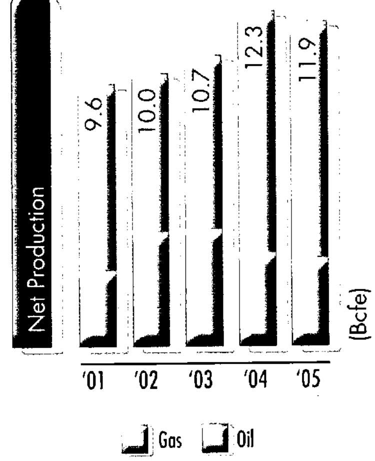
Brigham Exploration Company's strategy is to achieve superior growth in shareholder value by **applying 3-D seismic** and other advanced technologies **to reduce the risks and finding costs in drilling for oil and natural gas reserves.**

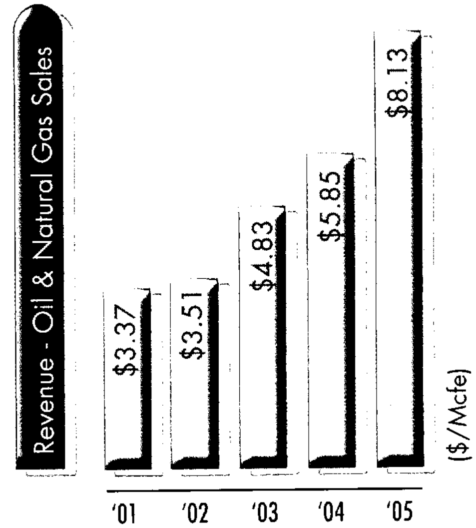
ASSETS

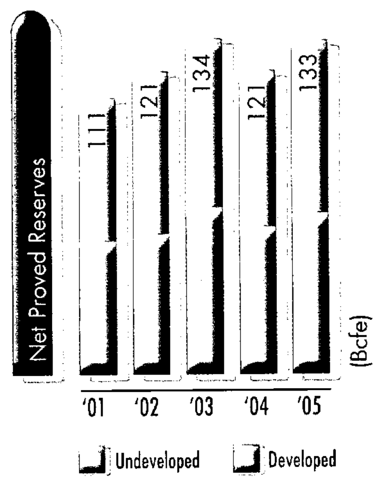
Brigham's principal assets include: (1) its **experienced technical staff**, including 15 geologists and geophysicists, (2) its **knowledge base** derived from its 15 year track record of successful 3-D exploration, including the drilling of over 680 3-D delineated wells in its 10,710 square mile inventory of 3-D seismic data, (3) its **recent field discoveries**, which provide a multi-year developmental drilling inventory to complement its large 3-D delineated exploration inventory, and (4) its **proved reserve base of 133 Bcfe** at year-end 2005 that is 85% natural gas and 51% proved developed.

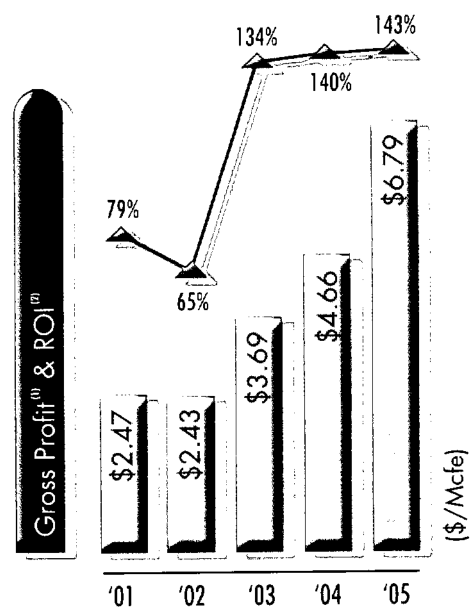
CORE PROVINCES

Brigham focuses its activity in established producing trends where 3-D technology may be effectively applied to generate large reserve discoveries, high production rates and high rates of return. Brigham's exploration and development activities are concentrated in three core onshore provinces: (1) the Onshore Gulf Coast, (2) the Anadarko Basin of western Oklahoma and the Texas Panhandle, and (3) West Texas.



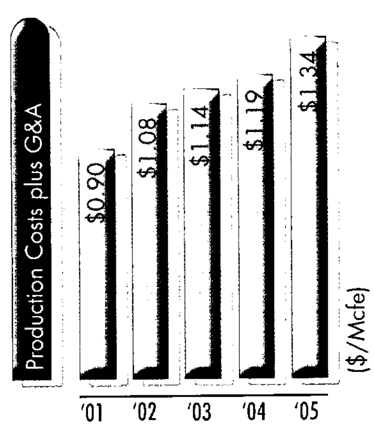






(1) Gross profit calculated as per unit revenue from oil and natural gas sales less per unit production cost and G&A.

(2) Return on investment calculated using per unit gross profit and our annual depletion rate.



Note: Production costs includes lease operating expenses, ad valorem taxes and production taxes.

CORE PROVINCES

1

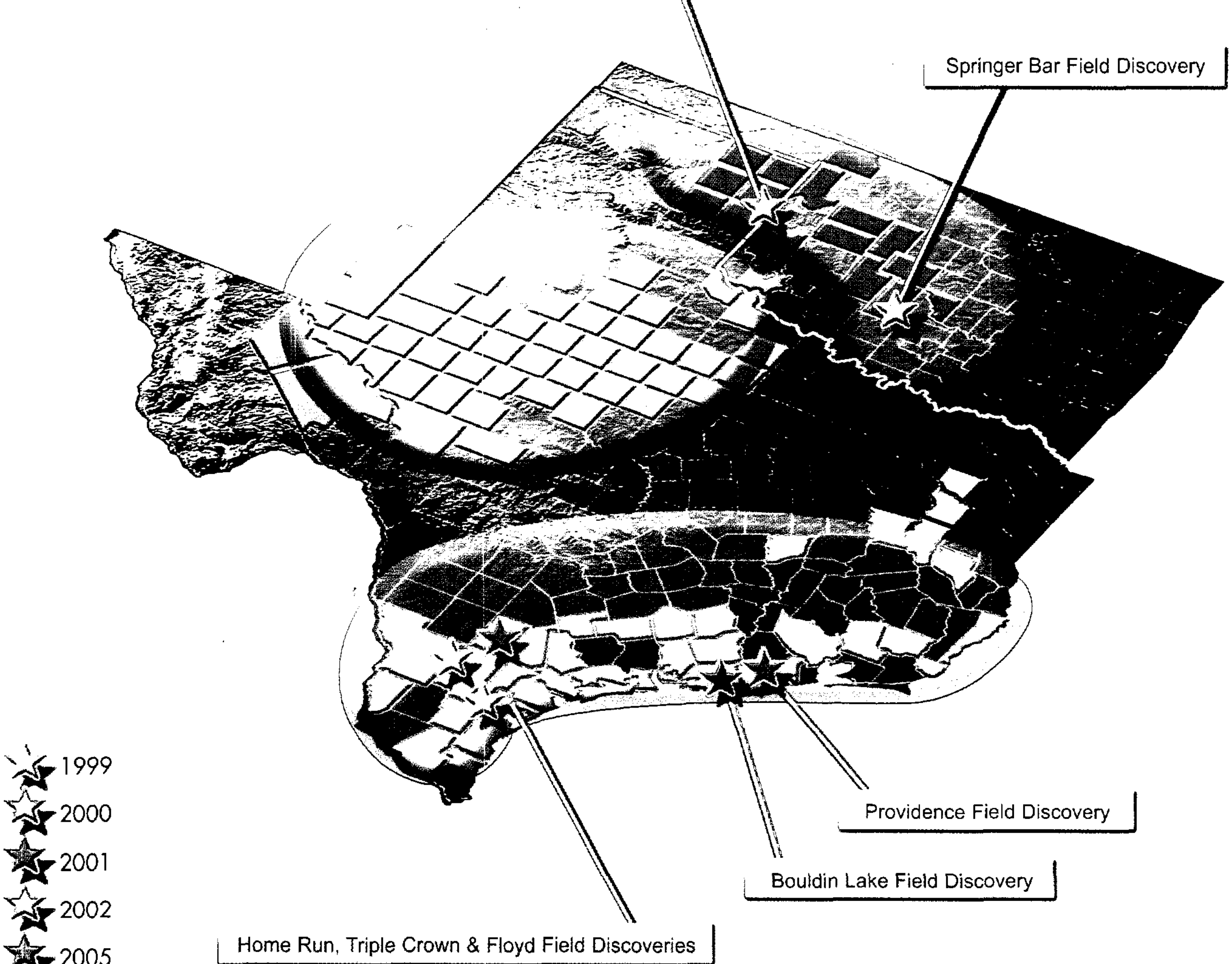
Onshore Gulf Coast

Assets at December 31, 2005	
Gross 3-D Sq. Miles	3,992
Net Proved Reserves (Bcfe)	76
Percent Gas	84%
Pre-tax PV10% Value ($MM)	$314
Three Year Results	
Wells Drilled/Completion Rate	53/89%

2

Anadarko Basin

Assets at December 31, 2005	
Gross 3-D Sq. Miles	2,204
Net Proved Reserves (Bcfe)	52
Percent Gas	93%
Pre-tax PV10% Value ($MM)	$184
Three Year Results	
Wells Drilled/Completion Rate	68/97%



3

Total Company

Assets at December 31, 2005	
Gross 3-D Sq. Miles	10,710
Net Proved Reserves (Bcfe)	133
Percent Gas	85%
Pre-tax PV10% Value ($MM)	$520
Three Year Results	
Wells Drilled/Completion Rate	131/92%

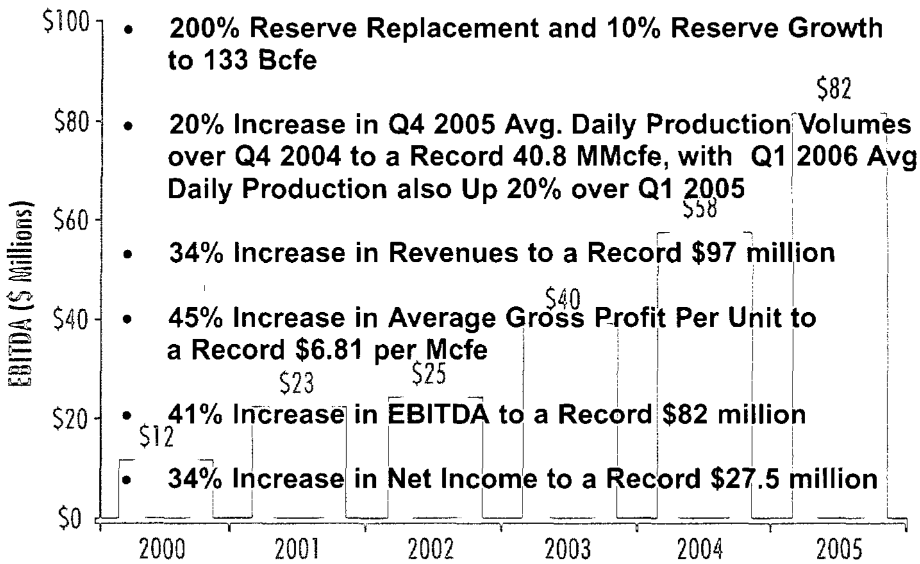
West Texas & Other

Assets at December 31, 2005	
Gross 3-D Sq. Miles	4,514
Net Proved Reserves (Bcfe)	5
Percent Gas	19%
Pre-tax PV10% Value ($MM)	$22
Three Year Results	
Wells Drilled/Completion Rate	10/70%

Ben M. "Bud" Brigham

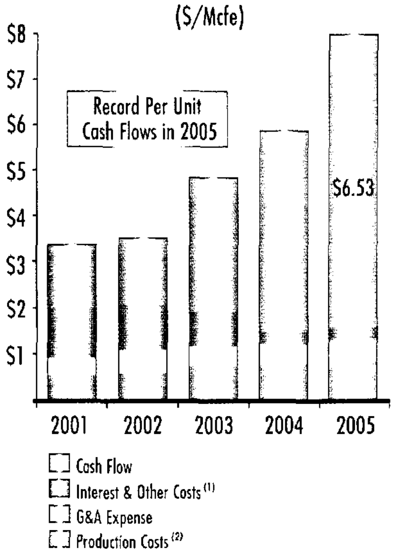
It is my pleasure to report to our shareholders on our accomplishments during 2005, a year of record financial performance for our company. During the year we achieved record revenues, margins, cash flows, and earnings, while continuing to keep our debt leverage low.

Operational highlights included outstanding results with our development drilling program, contributing to a 37% increase in average daily production in the fourth quarter relative to that of the first half of the year. We also added significant and potentially very exciting acreage positions in several unconventional plays, which should complement our successful conventional exploration and development program. Thanks to our successful drilling in 2005, we entered 2006 with production volumes at record levels, providing us with a "running start" as we enter 2006. More specifically, during 2005 we achieved:



- **200% Reserve Replacement and 10% Reserve Growth to 133 Bcfe**
- **20% Increase in Q4 2005 Avg. Daily Production Volumes over Q4 2004 to a Record 40.8 MMcfe, with Q1 2006 Avg. Daily Production also Up 20% over Q1 2005**
- **34% Increase in Revenues to a Record $97 million**
- **45% Increase in Average Gross Profit Per Unit to a Record $6.81 per Mcfe**
- **41% Increase in EBITDA to a Record $82 million**
- **34% Increase in Net Income to a Record $27.5 million**

Per Unit Costs & Cash Flow
($/Mcfe)



(1) Net interest, preferred dividend & cash settlement of non-cash flow derivatives.
(2) LOE, ad valorem taxes & production taxes.

CATALYSTS FOR GROWTH

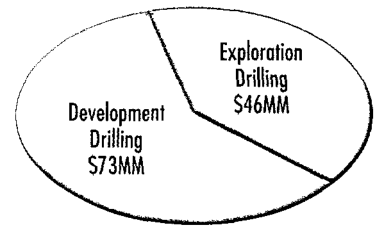
Looking forward to 2006, we see two important catalysts for growth. First, we believe that the momentum provided by our successful development drilling program provides us with excellent visibility for meaningful proved developed reserve and production growth during the year.

Second, we've made seven substantial field discoveries in seven years, and we'll be very disappointed if we don't make another meaningful discovery in 2006, further adding to our already deep inventory of developmental projects. In addition, our growing diversified inventory of unconventional plays complements our conventional projects, and like our high potential exploration program provides exciting potential for substantially accelerated growth in shareholder net asset value.

First Catalyst: Successful Development Drilling

As evidenced by our strong production ramp late in the year, our 2005 development drilling program was very efficient. Allocating the drilling capital expenditures to the 23 development wells we drilled during the year, we estimate that our proved developed drilling cost for our 2005 development wells was approximately $2.76 per Mcfe. Given the low production cost nature of our reserves, our wells generate high margins and high present values. As a result, we believe that each dollar we invested in development drilling during 2005 generated roughly $2 in proved developed PV10% value.

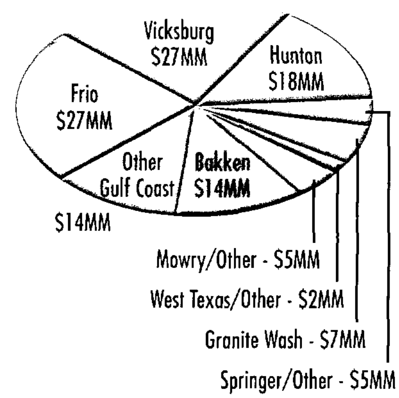
2006 Net Drilling Capex - $119MM



Given that success, during 2006 we expect to invest approximately $73 million in development drilling, up roughly 55% relative to 2005. Assuming our 2006 development drilling generates the same $2.76 per Mcfe proved developed drilling cost as 2005, we would add approximately 26 Bcfe in proved developed reserves in this year, which would be more than double our 2005 production of 11.9 Bcfe.

Our developmental drilling success was led by the Vicksburg, where we drilled five successful development wells at an estimated proved developed drilling cost of approximately $1.67 per Mcfe. Given the Vicksburg's low operating expense, and the associated high present value of Vicksburg production, we believe that each dollar we invested in drilling our 2005 Vicksburg wells generated more than $3 in proved developed PV10% value. During 2006 we intend to capitalize on this momentum, we now expect to invest over $26 million of our approximately $73 million development drilling budget in the Vicksburg, up more than 35% relative to 2005. Again, assuming last year's performance, the Vicksburg by itself provides us with the opportunity to more than replace our 2006 total company production. Fortunately, our development drilling program has delivered in our other plays as well, particularly the Hunton and the Granite Wash, where we again have a very active program underway. Given this high quality developmental program, we believe the visibility for our growth in proved developed reserves and production during 2006 is better than ever.

2006 Drilling Expenditures by Play

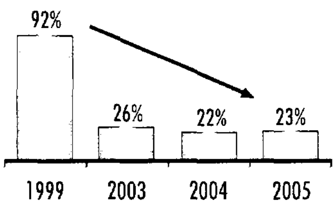


Second Catalyst: High Potential Exploration & New Unconventional Plays

The second catalyst for growth is provided both by our high reserve potential exploration program, and our relatively new inventory of exciting unconventional projects. During 2006 these projects provide our shareholders with exciting option value for a significant acceleration in our growth in net asset value.

We currently plan to drill seven high reserve potential wells in 2006, exposing our company to a net reserve potential that is more that double that of our year-end 2005 reserves. This company has a proven track record for making significant field discoveries, though we generally had smaller working interests than we're currently retaining. **Over the last seven years we've made seven substantial field discoveries that have already generated approximately 310 Bcfe in gross proved reserve additions, an average of roughly 46 Bcfe per field.** Our proved reserves in these fields has been growing over time, as they also have meaningful probable and possible associated reserves that over time have moved into the proved category. Given our historical success at making these field discoveries, and particularly given the quality

Debt to Book Capitalization



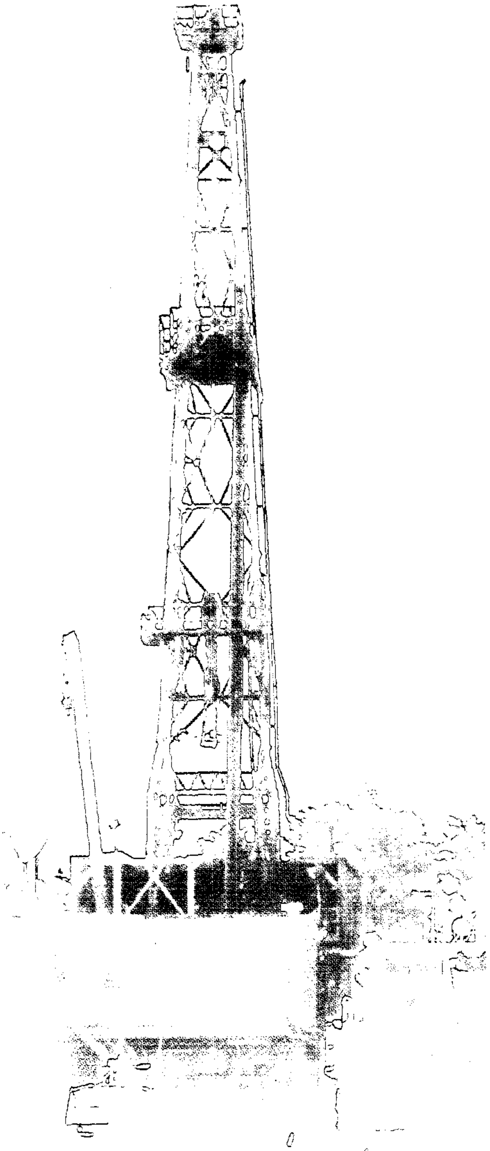
of the high potential prospects we expect to test this year, I'll be very disappointed if we don't make at least one significant field discovery in 2006. Because our working interests are generally double that of earlier years, field discoveries this year could be substantially more impactful for our shareholders.

Regarding our unconventional inventory, after commencing our initiative in early 2005 to build a complementary and diversified inventory of unconventional projects, we've now "placed our bets" on four unconventional plays, providing various levels of risk and reward. Of course we've been active in the Granite Wash of the Anadarko Basin for over ten years now, and as evidenced by our recent drilling successes it is very much a proven unconventional play. The last three wells we've completed in our Hobart Granite Wash project have commenced production at initial rates of between 4.0 and 5.1 MMcfed, providing very attractive economics at $7 per Mcf gas prices.

We also have over 5,000 acres in another relatively proven unconventional play, the Barnett Shale, where activity by other operators is apparently proving up reserve potential on our acreage. **However, the most substantial potential upside for our shareholders lies in two unconventional oil shale plays. In one of these, the Bakken of the Williston Basin, we expect to have substantially delineated the drilling economics by year-end.** Thus far we're very encouraged, given that the first horizontal well proximal to our Bakken acreage was reportedly completed at an initial rate of approximately 200 barrels of oil per day, despite some apparent operational difficulties. During the second quarter we are commencing the first of at least three Bakken wells in this same area, where we expect to have approximately 75,000 net acres by mid-year. With continued encouragement, we could grow our position further in this play. Given that we should have results from these three horizontal wells by the third quarter, and given the 15 to 25 additional horizontal wells that we expect other operators to drill during the year in the same area, we expect to be well along the way towards a "proof of concept" this year. The potential upside is very significant, with roughly 117 potential drilling locations, and over 200 Bcfe of potential net reserves, we estimate that the unrisked potential net asset value impact could range between $8 and $18 per share, obviously depending on success.

OPTIMIZING OUR PERFORMANCE

Looking back at 2005, there are things we did well, such as our successful development drilling, and the addition of new inventories of potential locations in various unconventional plays. On the other hand, our exploration finding costs in 2005 were too high, and this is an area that we've excelled in over our 15 plus year history. The Frio makes up a substantial portion of our exploration drilling, historically it's provided us with high rates of return on our drilling investments and several substantial field discoveries. Over time, as we've moved to the southwest in the Frio trend, we've begun targeting deeper, and substantially larger, Lower Frio targets. However, at the same time we've also encountered more "rock risk" - more of our wells are encountering Frio sands with lower porosities and permeabilities than those we encountered when we were drilling primarily in Matagorda and Brazoria counties to the northeast. That being said, there are a number of 100+ Bcfe Lower Frio fields in the area. Further, we've had a track record of discoveries in the trend, including Providence in 2002 and Bouldin Lake last year, and we therefore believe we have an excellent chance of finding another one. Although our high potential Frio program is outstanding, we've adjusted our program this year in order to improve the probability of delivering attractive all-sources finding costs, each and every year. Following is a summary of the various ways we've optimized our strategy in 2006:



- **First, we're capitalizing on our 2005 development drilling success by increasing our 2006 development drilling expenditures by roughly 55%.** The majority of this capital is going to the same plays that generated our fourth quarter 2005 surge in production volumes. We believe that this program provides excellent visibility for growth in proved developed reserves and production volumes during 2006.

- **Second, we've optimized our non-proved Gulf Coast drilling program by blending in lower risk and moderate reserve potential South Louisiana projects with our generally higher risk, but very high reserve potential Gulf Coast Frio program.** We believe that, in time, we are going to make a very substantial field discovery in the Lower Frio that will have a meaningful impact on our net asset value. However, the addition of the lower risk moderate reserve potential South Louisiana projects improves the probability that we will deliver solid new reserve adds in 2006 at attractive all-sources finding and development costs.

- **Third, we've "bolted on" a diversified unconventional program** that, like our high reserve potential exploration program, provides our shareholders with exciting option value on a potentially substantial acceleration of growth in shareholder net asset value.

In summary, we'll continue to be focus on efficiently converting our deep inventory of non-producing assets to production and cash flow. At the same time, we will continue to keep our inventory deep, providing plenty of fuel for future growth. As a company, we are in the "sweet spot" for organic growth, and our long-range plan for building shareholder value is very much on track. I believe that 2006 is shaping up to be possibly our most exciting year, ever.

In closing, I want to thank our dedicated employees, our loyal business partners, and our new and longstanding fellow shareholders. To all of you, I say "THANK YOU." We look forward to reporting on what should be a very memorable year for all of us.

Ben M. Brigham
Chairman of the Board
President and Chief Executive Officer
April 19, 2006

2005:	Gulf Coast	Anadarko Basin	W. Texas & Other
Drilling	**$61.6**	**$25.3**	**$4.0**
Net Land & Seismic	**9.9**	**2.1**	**7.6**
Total E&D	**$71.5**	**$27.4**	**$11.6**
Wells Drilled	18	15	3
Avg. WI%	73%	37%	100%
Avg. Daily Production	18.9	11.3	2.9
Pre-tax PV10% Value	$313.6	$184.4	$21.8
2006 Budget:			
Drilling CAPEX	**$65.7**	**$32.7**	**$22.0**
Net Land & Seismic	**12.8**	**11.3**	**4.5**
Total E&D	**$78.5**	**$44.0**	**$26.5**
Wells Planned	20	15	8
Average WI%	57%	45%	86%

* All dollar amounts in millions.

FINANCIAL HIGHLIGHTS

($000, except per share and per Mcfe data)	2001	2002	2003	2004	2005
Operating Data:					
Revenue from the sale of oil and natural gas	$32,293	$35,100	$51,545	$71,713	$96,820
Total revenue	32,548	35,176	51,677	72,228	97,040
Operating income *(loss)*	10,011	9,335	21,910	32,831	46,783
Net cash provided *(used)* by operating activities	18,922	28,973	41,691	56,381	64,379
Net income *(loss)* to common stockholders	9,224[a]	(676)	14,582	19,650	27,435
Per Diluted Share Data:					
Weighted average shares outstanding *(000)*	28,205	16,138	34,354	41,616	43,728
Net income *(loss)* per share	$0.44[a]	($0.04)	$0.51	$0.47	$0.63
Oil & Natural Gas Capital Expenditure Data:					
Net drilling	$27,200	$19,800	$35,106	$68,205	$90,873
Net land and G&G	2,559	3,048	6,074	12,993	19,641
Capitalized G&A and interest	6,050	5,656	6,081	5,714	6,789
Asset retirement obligations	-	-	269	513	1,324
Total	$35,809	$28,504	$47,530	$87,425	$118,627
Summary Balance Sheet Data:					
Cash and cash equivalents	$5,112	$15,318	$5,779	$2,281	$3,975
Oil and natural gas properties, net	153,017	166,006	198,490	261,979	347,329
Total assets	174,201	203,085	224,982	286,307	380,427
Total debt	91,721	81,797	39,000	41,000	63,100
Series A preferred stock[b]	16,614	19,540	8,794	9,520	10,101
Series B preferred stock[c]	-	4,777	-	-	-
Stockholders' equity	50,727	62,775	139,111	183,276	241,640
Per Mcfe Data:					
Revenue from the sale of oil and natural gas	$3.37	$3.51	$4.83	$5.85	$8.13
Other revenue	0.03	0.01	0.01	0.04	0.02
Total revenue	$3.40	$3.52	$4.84	$5.89	$8.15
Lease operating expenses	0.36	0.38	0.49	0.50	0.60
Production taxes	0.16	0.20	0.23	0.25	0.28
G&A expenses	0.38	0.50	0.42	0.44	0.46
Gross profit per Mcfe	$2.50	$2.44	$3.70	$4.70	$6.81

Year Ended December 31,

(a) Weighted average shares outstanding includes 11 million shares of common stock related to convertible debt and warrants related to Series A preferred stock deemed common stock equivalents under the "If-converted" method. Interest expense of $826,000 related to the convertible debt and dividends and accretion of $2.4 million related to Series A preferred stock were added back to net income to calculate diluted per share amounts. In addition, weighted average shares oustanding includes 1.2 million shares related to warrants and options that were deemed common stock equivalents under the "Treasury Method".

(b) Year end liquidation value of Series A preferred stock was $20.0 million in 2000, $32.6 million in 2001 and $35.3 million in 2002.

(c) Year end liquidation value of Series B preferred stock was $10.0 million in 2002.

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

Form 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2005

or

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

For the transition period from to

Commission file number: 000-22433

Brigham Exploration Company
(Exact name of Registrant as Specified in its Charter)

Delaware	**75-2692967**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*

6300 Bridge Point Parkway, Building 2, Suite 500, Austin, Texas 78730
(Address of principal executive offices) (Zip Code)

(512) 427-3300
(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
None	None

Securities registered pursuant to Section 12(g) of the Act:
Common Stock, $.01 par value
(Title of Class)

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 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.

Large accelerated filer ☐ Accelerated filer ☑ Non-accelerated filer ☐

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

As of June 30, 2005, the registrant had 42,538,196 shares of voting common stock outstanding. The aggregate market value of the registrants outstanding shares of voting common stock held by non-affiliates, based on the closing price of these shares on June 30, 2005 of $9.13 per share as reported on The NASDAQ Stock Market[SM], was $232 million. Shares held by each executive officer and director and by each person who owns 10% or more of the outstanding common stock are considered affiliates. The determination of affiliate status is not necessarily a conclusive determination for other purposes.

As of February 27, 2006, the registrant had 45,394,108 shares of voting common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement for the Registrant's 2006 Annual Meeting of Stockholders to be held on June 1, 2006, are incorporated by reference in Part III of this Form 10-K. Such definitive proxy statement will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2005.

BRIGHAM EXPLORATION COMPANY

TABLE OF CONTENTS

BRIGHAM EXPLORATION COMPANY

2005 ANNUAL REPORT ON FORM 10-K

PART I

Item 1. *Business*

Overview

We are an independent exploration, development and production company that utilizes 3-D seismic imaging and other advanced technologies to systematically explore for and develop domestic onshore oil and natural gas reserves. We focus our exploration and development activities in provinces where we believe technology and the knowledge of our technical staff can be used effectively to maximize our return on invested capital by reducing drilling risk and enhancing our ability to grow reserves and production volumes. Our 3-D seismic exploration and development activities are currently concentrated in three provinces: the onshore Gulf Coast, the Anadarko Basin in northwest Oklahoma and the Texas Panhandle and West Texas. We also regularly evaluate opportunities to expand our activities to other areas that may offer attractive exploration and development potential, with a particular interest in those areas with plays that complement our current exploration, development and production activities. As a result, we recently announced the acquisition of acreage in the Bakken play in North Dakota and announced joint ventures with two operators in Southern Louisiana.

At December 31, 2005, our estimated proved reserves, which had a standardized measure value of $396.3 million and a pre-tax PV10% value of $519.8 million, were 133.2 Bcfe. Approximately 85% of our proved reserves were natural gas and we operated approximately 69% of the pre-tax PV10% value. For the twelve month period ended December 31, 2005, our revenue and net income were $97 million and $27.4 million, respectively, while our average daily production was 33.1 MMcfe. Our average daily production for the fourth quarter 2005 was 40.8 MMcfe.

The following table provides information regarding our assets and operations located in our core areas.

	At December 31, 2005						2005
				Productive Wells			
Province	Proved Reserves (Bcfe)	Pre-tax PV10%(a) (Millions)	% Natural Gas	Gross	Net	3-D Seismic Data (Sq. Miles)	Average Daily Production (MMcfe)
Onshore Gulf Coast	75.8	$313.6	84%	86	36.8	3,992	18.9
Anadarko Basin	52.2	184.4	93%	189	42.0	2,204	11.3
West Texas/Other	5.2	21.8	19%	88	25.3	4,514	2.9
Total	133.2	$519.8(b)	85%	363	104.1	10,710	33.1

(a) The prices used to calculate this measure were $61.04 per barrel of oil and $9.44 per MMbtu of natural gas, both as of December 31, 2005.

(b) The standardized measure for our proved reserves at December 31, 2005 was $396.3 million. See "Item 2. Properties — Reconciliation of Standardized Measure to Pre-tax PV10%" for a definition of pre-tax PV10% and a reconciliation of our standardized measure to our pre-tax PV10% value.

Since our inception in 1990, we have evolved from a pioneering, 3-D seismic-driven exploration company to a balanced exploration and development company with technical and operational expertise and a strong production base. We have generated a multi-year inventory of exploration prospects, which due to our field discoveries, are complemented by a multi-year inventory of development locations. At December 31, 2005, we had over 190 potential exploration prospects and approximately 151 potential development drilling locations. In February 2006, we announced joint ventures with two operators in Southern Louisiana, which are expected to add nine potential exploration prospects and two potential development drilling locations. In addition, depending on the success of our initial wells, our November 2005 acreage acquisition in the Bakken play could add 63 to 126 additional drilling locations.

Since inception through December 31, 2005, we have drilled 688 wells, consisting of 482 exploration and 206 development wells with an aggregate completion rate of 73%. Over the three year period ended December 31, 2005, we drilled 131 wells, consisting of 52 exploratory and 79 development wells with an aggregate completion rate of 92%. During 2005, we spud a total of 36 wells, consisting of 12 exploration wells and 24 development wells and retained an average working interest in these wells of approximately 60%. Thirty-four of these wells have been or are currently being completed while two of these wells were not completed. Including one well that began drilling in 2004 and was completed in 2005, for 2005 our average completion rate was 94%.

We have accumulated 3-D seismic data covering approximately 10,710 square miles (6.9 million acres) in over 28 geologic trends in seven provinces and seven states. We generally focus our 3-D seismic acquisition efforts in and around existing producing fields where we can benefit from the imaging of producing analog wells. These 3-D defined analogs, combined with our experience in drilling 688 wells in our 3-D project areas, provide us with a knowledge base to evaluate other potential geologic trends, 3-D seismic projects within these trends and prospective 3-D delineated drilling locations. Over the three year period ended December 31, 2005, within our three core provinces, we spent $34.1 million on land and seismic activities and for 2006 currently plan to spend $25.5 million. In addition, in November 2005 we closed on a $4.6 million acquisition of a 100% working interest in approximately 46,000 net acres in the North Dakota portion of the Bakken play. Further, in February 2006, we announced joint ventures with two operators where we will retain average working interests between 36% and 48% in three prospect areas in Southern Louisiana. We consider our South Louisiana joint ventures to be a logical extension of our prospect generation activities in our onshore Gulf Coast province.

Combining our geologic and geophysical expertise with a sophisticated land effort, we manage a significant majority of our projects from conception through 3-D acquisition, processing and interpretation, as well as leasing. In addition, we manage the negotiation and drafting of most of our geophysical exploration agreements, resulting in reduced contract risk and more consistent deal terms. Because we generate most of our projects, we can often control the size of the working interest that we retain as well as the selection of the operator and the non-operating participants. We expect to operate the drilling operations for the majority of the wells on our new Bakken and Southern Louisiana acreage.

In 2005, we increased our level of drilling activity to further capitalize on our multi-year inventory of exploration and development prospects by spending a total of $90.9 million on drilling expenditures. This represents a 33% increase over the amounts we spent on drilling in 2004. These drilling expenditures were used to drill 12 exploratory wells and 22 development wells and for other development activities. We also had two development wells, the State Tract 266 #1 and the Mother Bear #3-28, that were in progress at December 31, 2005.

For 2006, we plan to continue with an active drilling program and will spend $120.4 million to drill 21 exploratory wells, and 22 development wells, as well as to drill and complete wells that were in progress at December 31, 2005 and for other development activities.

Business Strategy

Our business strategy is to create value for our stockholders by growing reserves, production volumes and cash flow through exploration and development drilling in areas where we believe our operations will likely result in a high return on our invested capital. Key elements of our business strategy include:

- *Focus on Core Provinces and Trends.* We have built our multi-year inventory of drilling prospects around a large and growing inventory of 3-D seismic data and our staff's strong technical knowledge base in the following geologic trends within our core provinces: the Vicksburg and Frio trends in the onshore Gulf Coast, the Springer and Hunton trends in the Anadarko Basin and the Horseshoe Atoll trend of West Texas. Further, we believe our focus on these five proven onshore trends within our three core provinces provides us with important drilling investment diversification. Since 1999, our exploration success in these trends has resulted in seven significant field discoveries and a resulting multi-year inventory of development drilling locations. We plan to focus a majority of our near term capital expenditures in these trends, where we believe our accumulated data and knowledge base provides us with a substantial competitive advantage.

- *Internally Generate Inventory of High Quality Exploratory Prospects.* Utilizing 3-D seismic data and other advanced technologies, our highly skilled staff of five geophysicists and ten geologists generates the majority of our drilling prospects. Historically, we have not relied on third party generated opportunities, which usually involve the payment of consideration over and above the costs incurred to generate and drill the prospect. We believe that our seven significant field discoveries reflect the quality and depth of our 3-D delineated prospect inventory as well our ability to continue to generate such opportunities.
- *Evaluate and Selectively Pursue New Potential Plays.* We have a 15 year track record of successfully evaluating and initiating new oil and natural gas plays. We are particularly interested in those plays with attractive exploration and development potential that complements our current exploration and production activities. After identifying such a play, we will often selectively build an acreage position in the play. Our current Frio, Vicksburg and Hunton plays are all examples of successful plays where our position in the play was identified and originated by us. We believe our recently announced acreage acquisition in the Bakken play and our recently announced joint ventures with two operators in Southern Louisiana are examples of new plays that could lead to growth in our future reserves and production. For 2006, we currently plan to spend approximately $17.7 million to drill four pilot wells within our Bakken acreage and $16.2 million to drill six wells in South Louisiana.
- *Capitalize on Exploration Successes Through Development of Field Discoveries.* From 1990 to 1999, we grew our reserves and production volumes primarily through successful 3-D delineated exploration drilling. Our exploratory drilling success over the past years has resulted in an multi-year inventory of development drilling locations, and over the three year period ended December 31, 2005, approximately 61% of our drilling expenditures were spent on development activities. We believe our ability to balance our higher risk exploratory drilling with lower risk development drilling has reduced our risk profile. For 2006, we intend to allocate approximately 61% of our planned drilling expenditures to development activities.
- *Continue to Actively Drill Our Multi-Year Prospect Inventory.* To capitalize on our multi-year inventory of exploration and development locations, for 2006 we plan to continue with our accelerated level of drilling activity. In 2005, we spent $90.9 million on drilling, representing a 33% increase over the amount we spent in 2004 and a 159% increase over the amount we spent in 2003. In 2006, we currently plan to spend $120.4 million in drilling capital. As has historically been the case, our 2006 drilling program will test several higher risk, but higher reserve potential prospects. During 2006, we plan to drill a total of seven such higher risk, but higher reserve potential tests.
- *Enhance Returns Through Operational Control.* We seek to maintain operational control of our exploration and drilling activities. As operator, we retain more control over the timing and selection of drilling prospects, which enhances our ability to optimize our finding and development costs and to maximize our return on invested capital. Since we generate most of our projects, we generally have the ability to retain operational control over all phases of our exploration and development activities. As of December 31, 2005, we operated approximately 69% of the pre-tax PV10% value of our proved reserves. Further, in 2005 we operated 69% of the wells we drilled, representing 94% of our drilling capital expenditures. We expect to operate approximately 79% of our wells planned for 2006, representing approximately 96% of our planned 2006 drilling capital expenditures.

Exploration and Development Staff

Our experienced exploration staff includes five geophysicists, ten geologists, two computer applications specialists and one geological technician. Our geologists and geophysicists have varied but complementary backgrounds, and their diversity of experience in a wide-range of geological and geophysical settings, combined with various technical specializations (from hardware and systems to software and seismic data processing), provides us with valuable technical intellectual resources. Our geophysicists and geologists have an average of more than 22 years of experience in the industry. We assembled our team to capitalize on the expertise our geophysicist and geologists encompass within producing basins where we focus our exploration and development activities. By integrating both geologic and geophysical expertise within our project teams, we believe we possess a competitive advantage in our exploration approach.

Our land department staff includes three landmen with an average of more than 25 years of experience, primarily within our core provinces, and three lease and division order analysts. Our land department contributed to pioneering many of the innovations that have facilitated exploration using large 3-D seismic projects.

Oil and Natural Gas Market and Major Customers

In 2002, in an effort to achieve better price realizations from the sale of our oil and natural gas, we decided to bring our commodities marketing activities in-house so that we could market and sell our oil and natural gas to a broader universe of potential purchasers. Due to the availability of other markets and pipeline connections, we do not believe that the loss of any single oil or natural gas customer would have a material adverse effect on our results of operations or cash flows.

Our natural gas produced in the onshore Gulf Coast is sold to various purchasers including intrastate pipeline purchasers, operators of processing plants, and marketing companies under both monthly spot market contracts and multi-year arrangements. The vast majority of our natural gas sales are based on related natural gas index pricing, and in some cases our gas is processed at a plant and we receive a percentage of the value of natural gas liquids recovered.

Our markets for natural gas produced in the Anadarko Basin are operators of processing plants and marketing companies. We sell gas under both monthly spot market contracts and multi-year contracts, which are normally based on related natural gas index pricing. Some of our natural gas is processed and we receive a percentage of the value of natural gas liquids recovered.

Most of our natural gas in West Texas is sold to purchasers who process our natural gas under multi-year contracts and pay us a percentage of the value they receive from the resale of the natural gas liquids and the remaining residue gas.

We sell our oil and condensate at the lease to a variety of purchasers at prevailing market prices under short-term contracts that normally provide for us to receive an applicable posted price plus a market-based bonus.

Since most of our oil and natural gas production is sold under price sensitive or spot market contracts, the revenues generated by our operations are highly dependent upon the prices of and demand for oil and natural gas. The price we receive for our oil and natural gas production depends upon numerous factors beyond our control, including seasonality, weather, competition, the condition of the United States economy, foreign imports, political conditions in other oil-producing and natural gas-producing countries, the actions of the Organization of Petroleum Exporting Countries, and domestic government regulation, legislation and policies. A decrease in the price of oil and natural gas could have an adverse effect on the carrying value of our proved reserves and on our revenues, profitability and cash flow. Although we are not currently experiencing any significant involuntary curtailment of our oil or natural gas production, market, economic and regulatory factors may in the future materially affect our ability to sell our oil or natural gas production. See "Item 1A. Risk Factors — Oil and natural gas prices are volatile and a substantial reduction in these prices could adversely affect our results and the price of our common stock" and "Item 1A. Risk Factors — The marketability of our oil and natural gas production depends on services and facilities that we typically do not own or control. The failure or inaccessibility of any such services or facilities could result in a curtailment of production and revenues."

Competition

The oil and natural gas industry is highly competitive in all of its phases. We encounter competition from other oil and natural gas companies in all areas of our operations, including the acquisition of seismic and leasing options on oil and natural gas properties to the exploration and development of those properties. Our competitors include major integrated oil and natural gas companies and numerous independent oil and natural gas companies, individuals and drilling and income programs. Many of our competitors are large, well established companies that have substantially larger operating staffs and greater capital resources than we do. Such companies may be able to pay more for seismic and lease options on oil and natural gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Our ability to acquire additional properties and to discover reserves in the future will depend upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. See "Item 1A. Risk Factors — We cannot control activities on properties we do not operate. Failure to fund capital expenditure requirements may result in reduction or forfeiture of our interests in some of our non-operated projects" and "Item 1A. Risk Factors — We face significant competition and many of our competitors have resources in excess of our available resources."

Operating Hazards and Uninsured Risks

Drilling activities are subject to many risks, including the risk that no commercially productive reservoirs will be encountered. There can be no assurance that the new wells we drill will be productive or that we will recover all or any portion of our investment. Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells, but also from wells that are productive, but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. The cost and timing of drilling, completing and operating wells is often uncertain. Our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, many of which are beyond our control, including title problems, weather conditions, delays by project participants, compliance with governmental requirements, shortages or delays in the delivery of equipment and services and increases in the cost for such equipment and services. Our future drilling activities may not be successful and, if unsuccessful, such failure may have a material adverse effect on our business, financial condition, results of operations and cash flows. See "Item 1A. Risk Factors — Our exploration, development and drilling efforts and the operation of our wells may not be profitable or achieve our targeted returns.", "Item 1A. Risk Factors — Exploratory drilling is a speculative activity that may not result in commercially productive reserves and may require expenditures in excess of budgeted amounts," "Item 1A. Risk Factors — Although our oil and natural gas reserve data is independently estimated, these estimates may still prove to be inaccurate" and "Item 1A. Risk Factors — The unavailability or high cost of drilling rigs, equipment, supplies, insurance, personnel and oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget."

In addition, use of 3-D seismic technology requires greater pre-drilling expenditures than traditional drilling strategies. Although we believe that our use of 3-D seismic technology will increase the probability of drilling success, some unsuccessful wells are likely, and there can be no assurance that unsuccessful drilling efforts will not have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our operations are subject to hazards and risks inherent in drilling for and producing and transporting oil and natural gas, such as fires, natural disasters, explosions, encountering formations with abnormal pressures, blowouts, cratering, pipeline ruptures and spills, any of which can result in the loss of hydrocarbons, environmental pollution, personal injury claims and other damage to our properties and those of others. We maintain insurance against some but not all of the risks described above. In particular, the insurance we maintain does not cover claims relating to failure of title to oil and natural gas leases, loss of surface equipment at well locations, trespass during 3-D survey acquisition or surface damage attributable to seismic operations, business interruption or loss of revenues due to well failure. Furthermore, in certain circumstances in which insurance is available, we may not purchase it. The occurrence of an event that is not covered, or not fully covered by insurance could have a material adverse effect on our business, financial condition, results of operations and cash flows in the period such may occur. See "Item 1A. Risk Factors — We are subject to various operating and other casualty risks that could result in liability exposure or the loss of production and revenues" and "Item 1A. Risk Factors — We may not have enough insurance to cover all of the risks we face, which could result in significant financial exposure."

Employees

On February 20, 2006, we had 62 full-time employees and two part-time employees. None of these employees are represented by any labor union and we believe relations with them are good.

Facilities

Our principal executive offices are located in Austin, Texas, where we lease approximately 34,330 square feet of office space at 6300 Bridge Point Parkway, Building 2, Suite 500, Austin, Texas 78730.

Governmental Regulation

Our oil and natural gas exploration, production, transportation and marketing activities are subject to extensive laws, rules and regulations promulgated by federal and state legislatures and agencies, including the Federal Energy Regulatory Commission (FERC), the Environmental Protection Agency (EPA), the Texas Commission on Environmental Quality (TCEQ), the Texas Railroad Commission, the Louisiana Department of Natural Resources, the Industrial Commission of North Dakota, the Oklahoma Corporation Commission and similar commissions of the other states in which we do business. Failure to comply with such laws, rules and regulations can result in substantial penalties. The legislative and regulatory burden on the oil and natural gas industry increases our cost of doing business and affects our profitability. See "Item 1A. Risk Factors — We are subject to various governmental regulations and environmental risks that may cause us to incur substantial costs."

Although we do not own or operate any pipelines or facilities that are directly regulated by FERC, its regulation of third party pipelines and facilities could indirectly affect our ability to transport or market our production. Moreover, FERC has in the past, and could in the future impose price controls on the sale of natural gas. In addition, we believe we are in substantial compliance with all applicable laws and regulations; however, we are unable to predict the future cost or impact of complying with such laws and regulations because they are frequently amended, interpreted and reinterpreted.

The states of Texas and Oklahoma, and most other states, require permits for drilling operations, drilling bonds and reports concerning operations and impose other requirements relating to the exploration and production of oil and natural gas. These states also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from wells and the regulation of spacing, plugging and abandonment of such wells.

Environmental Matters

Our operations and properties are, like the oil and natural gas industry in general, subject to extensive and changing federal, state and local laws and regulations relating to environmental protection, including the generation, storage, handling, emission, transportation and discharge of materials into the environment, and relating to safety and health. The recent trend in environmental legislation and regulation generally is toward stricter standards, and this trend will likely continue. These laws and regulations may require a permit or other authorization before construction or drilling commences and for certain other activities;

limit or prohibit access, seismic acquisition, construction, drilling and other activities on certain lands lying within wilderness and other protected areas; impose substantial liabilities for pollution resulting from our operations; and require the reclamation of certain lands.

The permits required for many of our operations are subject to revocation, modification and renewal by issuing authorities. Governmental authorities have the power to enforce compliance with their regulations, and violations are subject to fines, injunctions, or both. In the opinion of management, we are in substantial compliance with current applicable environmental laws and regulations, and we have no material commitments for capital expenditures to comply with existing environmental requirements. Nevertheless, changes in existing environmental laws and regulations or in interpretations thereof could have a significant impact on us, as well as the oil and natural gas industry in general. The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) and comparable state statutes impose strict and arguably joint and several liabilities on owners and operators of certain sites and on persons who disposed of or arranged for the disposal of "hazardous substances" found at such sites. It is not uncommon for the 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. The Resource Conservation and Recovery Act (RCRA) and comparable state statutes govern the disposal of "solid waste" and "hazardous waste" and authorize imposition of substantial fines and penalties for noncompliance. Although CERCLA currently excludes petroleum from its definition of "hazardous substance," state laws affecting our operations impose clean-up liability relating to petroleum and petroleum related products. In addition, although RCRA classifies certain oil field wastes as "non-hazardous," such exploration and production wastes could be reclassified as hazardous wastes, thereby making such wastes subject to more stringent handling and disposal requirements.

Federal regulations require certain owners or operators of facilities that store or otherwise handle oil, such as us, to prepare and implement spill prevention, control countermeasure and response plans relating to the possible discharge of oil into surface waters. The Oil Pollution Act of 1990 (OPA) contains numerous requirements relating to the prevention of and response to oil spills into waters of the United States. For onshore and offshore facilities that may affect waters of the United States, the OPA requires an operator to demonstrate financial responsibility. Regulations are currently being developed under federal and state laws concerning oil pollution prevention and other matters that may impose additional regulatory burdens on us. In addition, the Clean Water Act and analogous state laws require permits to be obtained to authorize discharge into surface waters or to construct facilities in wetland areas. The Clean Air Act of 1970 and its subsequent amendments in 1990 and 1997 also impose permit requirements and necessitate certain restrictions on point source emissions of volatile organic carbons (nitrogen oxides and sulfur dioxide) and particulates with respect to certain of our operations. We are required to maintain such permits or meet general permit requirements. The EPA and designated state agencies have in place regulations concerning discharges of storm water runoff and stationary sources of air emissions. These programs require covered facilities to obtain individual permits, participate in a group or seek coverage under an EPA general permit. Most agencies recognize the unique qualities of oil and natural gas exploration and production operations. Both the EPA and TCEQ have adopted regulatory guidance in consideration of the operational limitations on these types of facilities and their potential to emit air pollutants. We believe that we will be able to obtain, or be included under, such permits, where necessary, and to make minor modifications to existing facilities and operations that would not have a material effect on us.

Coastal Coordination. There are various federal and state programs that regulate conservation and development of coastal resources. The federal Coastal Zone Management Act, (CZMA) was passed to preserve and, where possible, restore the natural resources of the United States' coastal zone. The CZMA provides for federal grants for the state management programs that regulate land use, water use and coastal development.

The Texas Coastal Coordination Act (CCA) provides for coordination among local and state authorities to protect coastal resources through regulating land use, water, and coastal development and establishes the Texas Coastal Management Program that applies in the nineteen counties that border the

Gulf of Mexico and its tidal bays. The CCA provides for the review of state and federal agency rules and agency actions for consistency with the goals and policies of the Coastal Management Plan. This review may affect agency permitting and may add a further regulatory layer to some of our projects.

The Louisiana Coastal Zone Management Program (LCZMP) was established to protect, develop and, where feasible, restore and enhance coastal resources of the state. Under the LCZMP, coastal use permits are required for certain activities, even if the activity only partially infringes on the coastal zone. Among other things, projects involving use of state lands and water bottoms, dredge or fill activities that intersect with more than one body of water, mineral activities, including the exploration and production of oil and natural gas, and pipelines for the gathering, transportation or transmission of oil, natural gas and other minerals require such permits. General permits, which entail a reduced administrative burden, are available for a number of routine oil and gas activities. The LCZMP and its requirement to obtain coastal use permits may result in additional permitting requirements and associated project schedule constraints.

See "Item 1A. Risk Factors — We are subject to various governmental regulations and environmental risks that may cause us to incur substantial costs."

Operations and Operations Staff

In an effort to retain better control of our project timing, drilling, operational costs and production volumes, over the past several years, we have significantly increased the percentage of the wells that we operate. We operated 69% of the gross wells and 93% of the net wells that we drilled during 2005, as compared with 10% of the gross wells and 17% of the net wells we drilled during 1996. As a result of our increased operational control in recent years, wells operated by us constituted 69% of the pre-tax PV10% value of our proved reserves at year-end 2005, as compared to only 5% at year-end 1996.

Our operations staff includes six engineers who all have drilling, reservoir, environmental or operations engineering experience primarily within our three core provinces. These engineers work closely with our geologists and geophysicists and are integrally involved in all phases of the exploration and development process, including preparation of pre- and post-drill reserve estimates, well design, production management and analysis of full cycle risked drilling economics. We conduct field operations for our operated oil and natural gas properties through our field production superintendent and third party contract personnel.

Website Access to Our Reports

We make available free of charge through our website, www.bexp3d.com, 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 the Securities and Exchange Commission. Information on our website is not a part of this report.

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

You should carefully consider the following risk factors, in addition to the other information set forth in this report. Each of these risk factors could adversely affect our business, operating results and financial condition.

Oil and natural gas prices are volatile and a substantial reduction in these prices could adversely affect our results and the price of our common stock.

Our revenues, operating results and future rate of growth depend highly upon the prices we receive for our oil and natural gas production. Historically, the markets for oil and natural gas have been volatile and are likely to continue to be volatile in the future. The NYMEX daily settlement price for the prompt month natural gas contract in 2004 ranged from a high of $8.14 per MMBtu to a low of $4.40 per MMBtu. In 2005, the same index ranged from a high of $15.38 per MMBtu to a low of $5.79 per MMBtu. The NYMEX daily settlement price for the prompt month oil contract in 2004 ranged from a high of $56.17 per barrel to a low of $32.48 per barrel. In 2005, the same index ranged from a high of

$69.81 per barrel to a low of $42.12 per barrel. The markets and prices for oil and natural gas depend on factors beyond our control. These factors include demand for oil and natural gas, which fluctuate with changes in market and economic conditions and other factors, including:

- worldwide and domestic supplies of oil and natural gas;
- actions taken by foreign oil and natural gas producing nations;
- political conditions and events (including instability or armed conflict) in oil-producing or natural gas-producing regions;
- the level of global oil and natural gas inventories;
- the price and level of foreign imports;
- the level of consumer demand;
- the price and availability of alternative fuels;
- the availability of pipeline capacity;
- weather conditions;
- domestic and foreign governmental regulations and taxes; and
- the overall economic environment.

Significant declines in oil and natural gas prices for an extended period may have the following effects on our business:

- limiting our financial condition, liquidity, ability to finance planned capital expenditures and results of operations;
- reducing the amount of oil and natural gas that we can produce economically;
- causing us to delay or postpone some of our capital projects;
- reducing our revenues, operating income and cash flow;
- reducing the carrying value of our oil and natural gas properties; and
- limiting our access to sources of capital, such as equity and long-term debt.

We may have difficulty financing our planned capital expenditures, which could adversely affect our business.

We make and will continue to make substantial capital expenditures in our exploration and development projects. Without additional capital resources, our drilling and other activities may be limited and our business, financial condition and results of operations may suffer. We may not be able to secure additional financing on reasonable terms or at all and financing may not continue to be available to us under our existing or new financing arrangements. If additional capital resources are unavailable, we may curtail our drilling, development and other activities or be forced to sell some of our assets on an untimely or unfavorable basis. Any such curtailment or sale could have a material adverse effect on our business, financial condition and results of operation. In addition, we have a limited number of shares of authorized but unissued common stock available at this time. While we intend to seek approval from our stockholders to increase our authorized stock, unless and until such change is approved, we would not have sufficient number of shares of authorized common stock to raise a substantial amount of proceeds to us in any subsequent public or private equity offering.

Our exploration, development and drilling efforts and the operation of our wells may not be profitable or achieve our targeted returns.

We require significant amounts of undeveloped leasehold acreage in order to further our development efforts. Exploration, development, drilling and production activities are subject to many risks, including the risk that commercially productive reservoirs will not be discovered. We invest in property, including undeveloped leasehold acreage, which we believe will result in projects that will add value over time. However, we cannot guarantee that all of our prospects will result in viable projects or that we will not abandon our initial investments. Additionally, we cannot guarantee that the leasehold acreage we acquire will be profitably developed, that new wells drilled by us in provinces that we pursue will be productive or that we will recover all or any portion of our investment in such leasehold acreage or wells. Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient net reserves to return a profit after deducting operating and other costs. In addition, wells that are profitable may not achieve our targeted rate of return. Our ability to achieve our target results is dependent upon the current and future market prices for oil and natural gas, costs associated with producing oil and natural gas and our ability to add reserves at an acceptable cost. We rely to a significant extent on 3-D seismic data and other advanced technologies in identifying leasehold acreage prospects and in conducting our exploration activities. The 3-D seismic data and other technologies we use do not allow us to know conclusively prior to the acquisition of leasehold acreage or the drilling of a well whether oil or natural gas is present or may be produced economically. The use of 3-D seismic data and other technologies also requires greater pre-drilling expenditures than traditional drilling strategies.

In addition, we may not be successful in implementing our business strategy of controlling and reducing our drilling and production costs in order to improve our overall return. The cost of drilling, completing and operating a well is often uncertain and cost factors can adversely affect the economics of a project. We cannot predict the cost of drilling, and we may be forced to limit, delay or cancel drilling operations as a result of a variety of factors, including:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs and the delivery of equipment.

Exploratory drilling is a speculative activity that may not result in commercially productive reserves and may require expenditures in excess of budgeted amounts.

Our future rate of growth greatly depends on the success of our exploratory drilling program. Exploratory drilling involves a higher degree of risk that we will not encounter commercially productive oil or natural gas reservoirs than developmental drilling. We may not be successful in our future drilling activities because even with the use of 3-D seismic and other advanced technologies, exploratory drilling is a speculative activity.

Although our oil and natural gas reserve data is independently estimated, these estimates may still prove to be inaccurate.

Our proved reserve estimates are generated each year by Cawley, Gillespie & Associates, Inc., an independent petroleum consulting firm. In conducting its evaluation, the engineers and geologists of Cawley, Gillespie & Associates, Inc. evaluate our properties and independently develop proved reserve estimates. There are numerous uncertainties and risks that are inherent in estimating quantities of oil and natural gas reserves and projecting future rates of production and timing of development expenditures as many factors are beyond our control. We incorporate many factors and assumptions into our estimates including:

- expected reservoir characteristics based on geological, geophysical and engineering assessments;
- future production rates based on historical performance and expected future operating and investment activities;
- future oil and gas prices and quality and location differentials; and
- future development and operating costs.

Although we believe the Cawley, Gillespie & Associates, Inc. reserve estimates are reasonable based on the information available to them at the time they prepare their estimates, our actual results could vary materially from these estimated quantities of proved oil and natural gas reserves (in the aggregate and for a particular location), production, revenues, taxes and development and operating expenditures. In addition, these estimates of proved reserves may be subject to downward or upward revision based upon production history, results of future exploration and development, prevailing oil and natural gas prices, operating and development costs and other factors.

Finally, recovery of proved undeveloped reserves generally requires significant capital expenditures and successful drilling operations. At December 31, 2005, approximately 49% of our estimated proved reserves were classified as undeveloped. At December 31, 2005, we estimated that it would require additional capital expenditures of approximately $122 million to develop these reserves. Our reserve estimates assume that we can and will make these expenditures and conduct these operations successfully, which may not occur.

We need to replace our reserves at a faster rate than companies whose reserves have longer production periods. Our failure to replace our reserves would result in decreasing reserves and production over time.

In general, production from oil and natural gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Except to the extent we conduct successful exploration and development activities or acquire properties containing proved reserves, or both, our proved reserves and production will decline as reserves are produced.

We may not be able to find, develop or acquire additional reserves to replace our current and future production. Accordingly, our future oil and natural gas reserves and production and therefore our future cash flow and income, are dependent upon our success in economically finding or acquiring new reserves and efficiently developing our existing reserves.

Our reserves in the Gulf Coast have high initial production rates followed by steep declines in production, resulting in a reserve life for wells in this area that is shorter than the industry average. This production volatility has impacted and, in the future, may continue to impact our quarterly and annual production levels.

We generally must locate and develop or acquire new oil and natural gas reserves to replace those being depleted by production. Without successful drilling and exploration or acquisition activities, our reserves and revenues will decline rapidly. We may not be successful in extending the reserve life of our properties generally and our Gulf Coast properties in particular. Our current strategy includes increasing our reserve base through drilling activities on our existing Gulf Coast properties and properties located in our other core areas, which have historically had longer-lived reserves. Our existing and future exploration and development projects may not result in significant additional reserves and we may not be able to drill productive wells at economically viable costs.

Our future cash flows are subject to a number of variables, such as the level of production from existing wells, prices of oil and natural gas and our success in finding and producing new reserves. If our revenues were to decrease as a result of lower oil and natural gas prices, decreased production or otherwise, and our access to capital were limited, we would have a reduced ability to replace our reserves or to maintain production at current levels, potentially resulting in a decrease in production and revenue over time.

Drilling locations that we decide to drill may not yield oil or natural gas in commercially viable quantities or quantities sufficient to meet our targeted rate of return.

Our drilling locations are in various stages of evaluation, ranging from locations that are ready to be drilled to locations that will require substantial additional evaluation and interpretation. There is no way to predict in advance of drilling and testing whether any particular drilling location will yield oil or natural gas in sufficient quantities to recover our drilling or completion costs or to be economically viable. Our 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 whether oil and natural gas will be present or, if present, whether oil and natural gas will be present in commercial quantities. The analysis that we perform using data from other wells, more fully explored prospects and/or producing fields may not be useful in predicting the characteristics and potential reserves associated with our drilling locations. As a result, we may not find commercially viable quantities of oil and natural gas and, therefore, we may not achieve a targeted rate of return or have a positive return on investment.

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

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies, insurance or qualified personnel. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, the demand for, and wage rates of, qualified drilling rig crews rise as the number of active rigs in service increases. As a result of increasing levels of exploration and production in response to strong prices of oil and natural gas, the demand for oilfield services has risen, and the costs of these services are increasing, while the quality of these services may suffer. If the unavailability or high cost of drilling rigs, equipment, supplies, insurance or qualified personnel were particularly severe in Texas and Oklahoma, we could be materially and adversely affected because our operations and properties are concentrated in those areas.

The marketability of our oil and natural gas production depends on services and facilities that we typically do not own or control. The failure or inaccessibility of any such services or facilities could result in a curtailment of production and revenues.

The marketability of our production depends in part upon the availability, proximity and capacity of natural gas gathering systems, pipelines and processing facilities. We generally deliver natural gas through gas gathering systems and gas pipelines that we do not own under interruptible or short term transportation agreements. Under the interruptible transportation agreements, the transportation of our natural gas may be interrupted due to capacity constraints on the applicable system, for maintenance or repair of the system, or for other reasons as dictated by the particular agreements. If any of the pipelines or other facilities become unavailable, we would be required to find a suitable alternative to transport and process the natural gas, which could increase our costs and reduce the revenues we might obtain from the sale of the natural gas. For example, Hurricane Rita disrupted the operations of natural gas pipelines and fractionators and required the evacuation of personnel required to oversee some of our facilities in the Gulf Coast area. As a result of these disruptions, we were forced temporarily to curtail some of our production in our onshore Gulf Coast province for approximately six days.

Our level of indebtedness may adversely affect our cash available for operations, which would limit our growth, our ability to make interest and principal payments on our indebtedness as they become due and our flexibility to respond to market changes.

At December 31, 2005, we had indebtedness of $33.1 million outstanding under our senior credit agreement and $30 million outstanding under our subordinated credit agreement. Our level of indebtedness will have several important effects on our operations, including those listed below.

- We will dedicate a portion of our cash flow from operations to the payment of interest on our indebtedness and to the payment of our other current obligations and will not have these cash flows available for other purposes.
- The covenants of our credit agreements limit our ability to borrow additional funds or dispose of assets and may affect our flexibility in planning for, and reacting to, changes in business conditions.
- Our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate purposes or other purposes may be impaired.
- We may be more vulnerable to economic downturns and our ability to withstand sustained declines in oil and natural gas prices may be impaired.
- Since our indebtedness is subject to variable interest rates, we are vulnerable to increases in interest rates.
- Our flexibility in planning for or reacting to changes in market conditions may be limited.

We may incur additional debt in order to fund our exploration and development activities. A higher level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and reduce our level of indebtedness depends on future performance. General economic conditions, oil and natural gas prices and financial, business and other factors will affect our operations and our future performance. Many of these factors are beyond our control and we may not be able to generate sufficient cash flow to pay the interest on our debt, and future working capital, borrowings and equity financing may not be available to pay or refinance such debt.

In addition, under the terms of our senior credit agreement, our borrowing base is subject to semi-annual redeterminations based in part on prevailing oil and natural gas prices. In the event the amount outstanding exceeds the redetermined borrowing base, we could be forced to repay a portion of our borrowings. We may not have sufficient funds to make such payments. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell assets at unfavorable prices.

Lower oil and natural gas prices may cause us to record ceiling limitation write-downs, which would reduce our stockholders' equity.

We use the full cost method of accounting to account for our oil and natural gas investments. Accordingly, we capitalize the cost to acquire, explore for and develop oil and natural gas properties. Under full cost accounting rules, the net capitalized cost of oil and natural gas properties may not exceed a "ceiling limit" that is based upon the present value of estimated future net revenues from proved reserves, discounted at 10%, plus the lower of the cost or fair market value of unproved properties. If net capitalized costs of oil and natural gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a "ceiling limitation write-down." The risk that we will be required to write down the carrying value of our oil and natural gas properties increases when oil and natural gas prices are low or volatile. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves. Once incurred, a write-down of oil and gas properties is not reversible at a later date. Write-downs required by these rules do not impact our cash flow from operating activities, but do reduce net income and stockholders' equity.

We are subject to various operating and other casualty risks that could result in liability exposure or the loss of production and revenues.

Our operations are subject to hazards and risks inherent in drilling for and producing and transporting oil and natural gas, such as:

- fires;
- natural disasters;
- formations with abnormal pressures;
- blowouts, cratering and explosions; and
- pipeline ruptures and spills.

Any of these hazards and risks can result in the loss of hydrocarbons, environmental pollution, personal injury claims and other damage to our properties and the property of others.

We may not have enough insurance to cover all of the risks we face, which could result in significant financial exposure.

We maintain insurance coverage against some, but not all, potential losses in order to protect against the risks we face. We may elect not to carry insurance if our management believes that the cost of insurance is excessive relative to the risks presented. If an event occurs that is not covered, or not fully covered, by insurance, it could harm our financial condition, results of operations and cash flows. In addition, we cannot fully insure against pollution and environmental risks.

We cannot control activities on properties we do not operate. Failure to fund capital expenditure requirements may result in reduction or forfeiture of our interests in some of our non-operated projects.

We do not operate some of the properties in which we have an interest and we have limited ability to exercise influence over operations for these properties or their associated costs. As of December 31, 2005, approximately 31% of our oil and natural gas properties, based on pre-tax PV10% value, were operated by other companies. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence operations and associated costs could materially adversely affect the realization of our targeted return on capital in drilling or acquisition activities and our targeted production growth rate. The success and timing of drilling, development and exploitation activities on properties operated by others depend on a number of factors that are beyond our control, including the operator's expertise and financial resources, approval of other participants for drilling wells and utilization of technology.

When we are not the majority owner or operator of a particular oil or natural gas project, we may have no control over the timing or amount of capital expenditures associated with such project. If we are not willing or able to fund our capital expenditures relating to such projects when required by the majority owner or operator, our interests in these projects may be reduced or forfeited.

Our future operating results may fluctuate and significant declines in them would limit our ability to invest in projects.

Our future operating results may fluctuate significantly depending upon a number of factors, including:

- industry conditions;
- prices of oil and natural gas;
- rates of drilling success;
- capital availability;

- rates of production from completed wells; and
- the timing and amount of capital expenditures.

This variability could cause our business, financial condition and results of operations to suffer. In addition, any failure or delay in the realization of expected cash flows from operating activities could limit our ability to invest and participate in economically attractive projects.

Our hedging activities may prevent us from benefiting from price increases and may expose us to other risks.

In an attempt to reduce our sensitivity to energy price volatility, we enter into hedging arrangements with respect to a portion of expected production, such as the use of derivative contracts that generally result in a fixed price or a range of minimum and maximum price limits over a specified time period.

Our hedging activities expose us to the risk of financial loss in certain circumstances. For example, if we do not produce our oil and natural gas reserves at rates equivalent to our derivative position, we would be required to satisfy our obligations under those derivative contracts on potentially unfavorable terms without the ability to offset that risk through sales of comparable quantities of our own production. This situation occurred during portions of 2000, due in part to our sale of certain producing reserves in mid-1999 and reduced our cash flow in 2000 by approximately $1.0 million. Additionally, because the terms of our derivative contracts are based on assumptions and estimates of numerous factors such as cost of production and pipeline and other transportation and marketing costs to delivery points, substantial differences between the prices we receive pursuant to our derivative contracts and our actual results could harm our anticipated profit margins and our ability to manage the risk associated with fluctuations in oil and natural gas prices. We also could be financially harmed if the counter parties to our derivative contracts prove unable or unwilling to perform their obligations under such contracts. Additionally, in the past, some of our derivative contracts required us to deliver cash collateral or other assurances of performance to the counter parties if our payment obligations exceeded certain levels. Future collateral requirements are uncertain but will depend on arrangements with our counter parties and highly volatile oil and natural gas prices.

We face significant competition and many of our competitors have resources in excess of our available resources.

We operate in the highly competitive areas of oil and natural gas exploration, exploitation, acquisition and production. We face intense competition from a large number of independent, technology-driven companies as well as both major and other independent oil and natural gas companies in a number of areas such as:

- seeking to acquire desirable producing properties or new leases for future exploration;
- marketing our oil and natural gas production; and
- seeking to acquire the equipment and expertise necessary to operate and develop those properties.

Many of our competitors have financial and other resources substantially in excess of those available to us. This highly competitive environment could harm our business.

We are subject to various governmental regulations and environmental risks that may cause us to incur substantial costs.

From time to time, in varying degrees, political developments and federal and state laws and regulations affect our operations. In particular, price controls, taxes and other laws relating to the oil and natural gas industry, changes in these laws and changes in administrative regulations have affected and in the future could affect oil and natural gas production, operations and economics. We cannot predict how agencies or courts will interpret existing laws and regulations or the effect of these adoptions and interpretations may have on our business or financial condition.

Our business is subject to laws and regulations promulgated by federal, state and local authorities, including the FERC, the EPA, the Texas Railroad Commission, the TCEQ and the Oklahoma Corporation Commission, relating to the exploration for, and the development, production and marketing of, oil and natural gas, as well as safety matters. Legal requirements are frequently changed and subject to interpretation and we are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations. We may be required to make significant expenditures to comply with governmental laws and regulations.

Our operations are subject to complex federal, state and local environmental laws and regulations, including CERCLA, RCRA, OPA and the Clean Water Act. Environmental laws and regulations change frequently, and the implementation of new, or the modification of existing, laws or regulations could harm us. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to significant liabilities on our part to the government and third parties and may require us to incur substantial costs of remediation.

We depend on our key management personnel and technical experts and the loss any of these individuals could adversely affect our business.

If we lose the services of our key management personnel or technical experts or are unable to attract additional qualified personnel, our business, financial condition, results of operations, development efforts and ability to grow could suffer. We have assembled a team of geologists, geophysicists and engineers who have considerable experience in applying 3-D seismic imaging technology to explore for and to develop oil and natural gas. We depend upon the knowledge, skill and experience of these experts to provide 3-D seismic imaging and to assist us in reducing the risks associated with our participation in oil and natural gas exploration and development projects. In addition, the success of our business depends, to a significant extent, upon the abilities and continued efforts of our management, particularly Ben M. Brigham, our Chief Executive Officer, President and Chairman of the Board. We have an employment agreement with Mr. Brigham, but do not have an employment agreement with any of our other employees.

The market price of our stock is volatile.

The trading price of our common stock and the price at which we may sell securities in the future are subject to large fluctuations in response to any of the following:

- limited trading volume in our stock;
- changes in government regulations;
- quarterly variations in operating results;
- our involvement in litigation;
- general market conditions;
- the prices of oil and natural gas;
- announcements by us and our competitors;
- our liquidity;
- our ability to raise additional funds; and
- other events.

Our stock price may decline when our financial results decline or when events occur that are adverse to us or our industry.

You can expect the market price of our common stock to decline when our financial results decline or otherwise fail to meet the expectations of the financial community or the investing public or at any other time when events actually or potentially adverse to us or the oil and natural gas industry occur. Our common stock price may decline to a price below the price you paid to purchase your shares of common stock.

We do not intend to pay any dividends on our common stock.

We anticipate that we will retain all future earnings and other cash resources for the future operation and development of our business. Accordingly, we do not intend to declare or pay any cash dividends on our common stock in the foreseeable future. Payment of any future dividends will be at the discretion of our board of directors after taking into account many factors, including our operating results, financial condition, current and anticipated cash needs and plans for expansion.

Our shares that are eligible for future sale may have an adverse effect on the price of our common stock.

Sales of substantial amounts of common stock, or a perception that such sales could occur, could adversely affect the market price of our common stock and could impair our ability to raise capital through the sale of our equity securities. At December 31, 2005, one of our stockholders, together with its affiliates, owned 16.6% of our outstanding common stock.

Certain of our affiliates control a substantial portion of our outstanding common stock, which may affect your vote as a stockholder.

Our directors, executive officers and 10% or greater stockholders, and certain of their affiliates, beneficially own a substantial portion of our outstanding common stock. Accordingly, these stockholders, as a group, 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. The existence of these levels of ownership concentrated in a few persons makes it unlikely that any other holder of our common stock may be able to affect our management or direction. These factors may also have the effect of delaying or preventing a change in our management or voting control.

Certain anti-takeover provisions may adversely affect your rights as a stockholder.

Our certificate of incorporation authorizes our Board of Directors to issue up to 10 million shares of preferred stock without stockholder approval and to set the rights, preferences and other designations, including voting rights, of those shares as the Board of Directors may determine. In addition, our Series A preferred stock, our senior credit agreement and our subordinated credit agreement contain terms restricting our ability to enter into change of control transactions, including requirements to redeem or repay our outstanding Series A preferred stock, the amounts borrowed under our senior credit agreement and the amounts borrowed under our subordinated credit agreement upon a change in control. These provisions, alone or in combination with the other matters described in the preceding paragraph may discourage transactions involving actual or potential changes in our control, including transactions that otherwise could involve payment of a premium over prevailing market prices to holders of our common stock. We are also subject to provisions of the Delaware General Corporation Law that may make some business combinations more difficult.

Forward-Looking Statements

This report and the documents incorporated by reference in this annual report on Form 10-K contain forward-looking statements within the meaning of the federal securities laws.

These forward-looking statements include, among others, the following:

- our growth strategies;
- our ability to successfully and economically explore for and develop oil and gas resources;
- anticipated trends in our business;

- our future results of operations;
- our liquidity and ability to finance our exploration and development activities;
- market conditions in the oil and gas industry;
- our ability to make and integrate acquisitions; and
- the impact of governmental regulation.

Forward-looking statements are typically identified by use of terms such as "may," "will," "expect," "anticipate," "estimate" and similar words, although some forward-looking statements may be expressed differently.

You should be aware that our actual results could differ materially from those contained in the forward-looking statements. You should consider carefully the statements in this "Item 1A. Risk Factors" and other sections of this report, which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements.

Item 1B. *Unresolved Staff Comments*

None.

Item 2. *Properties*

Historically, our exploration and development activities have been focused primarily in the onshore Gulf Coast, the Anadarko Basin in northwest Oklahoma and the Texas Panhandle, and West Texas. We focus our activity in provinces where we believe technology and the knowledge of our technical staff can be effectively used to maximize our return on invested capital by reducing drilling risk and enhancing our ability to grow reserves and production volumes. We also regularly evaluate opportunities to expand our activities to areas that may offer attractive exploration and development potential, with a particular interest in those plays that complement our current exploration, development and production activities. As a result, we recently announced the acquisition of acreage in the Bakken play in North Dakota and announced joint ventures with two operators in Southern Louisiana.

For the three-year period ended December 31, 2005, we completed 120 gross wells (56.4 net) in 131 attempts for a completion rate of 92%. We also had two development wells (1.0 net) that were in progress at December 31, 2005. For 2006, we plan to spend approximately $120.4 million to drill 21 exploration wells and 22 development wells, to drill and complete wells that were in progress at December 31, 2005 and for other development activities. We also plan to spend $28.6 million on land and seismic, $7.3 million for capitalized costs and $559,000 for other assets. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Capital Commitments — Capital Expenditures." The following is a summary of our properties by major province as of December 31, 2005, unless otherwise noted.

	Onshore Gulf Coast	Anadarko Basin	West Texas & Other(a)	Total
Capital expenditures for drilling, land and seismic in 2005 (in millions)	$ 71.5	$ 27.4	$11.6	$110.5
Proved Reserves at December 31, 2005				
Pre-tax PV10% (in millions)	$313.6	$184.4	$21.8	$519.8(b)
Oil (MMBbls)	2.0	0.6	0.7	3.3
Natural gas (Bcf)	63.5	48.8	1.0	113.3
Natural gas equivalents (Bcfe)	75.8	52.2	5.2	133.2
% Natural gas	84%	93%	19%	85%
Average daily production (MMcfe/d)	18.9	11.3	2.9	33.1
Productive wells at December 31, 2005				
Gross	86	189	88	363
Net	42.0	36.8	25.3	104.1
3-D Seismic Data (square miles)	3,992	2,204	4,514	10,710

(a) Includes capital expenditures associated with Williston Basin activities.

(b) The standardized measure for our proved reserves at December 31, 2005, was $396.3 million. See "— Reconciliation of Standardized Measure to Pre-tax PV10%" for a definition of pre-tax PV10% and a reconciliation of our standardized measure to our pre-tax PV10% value.

Onshore Gulf Coast

The onshore Gulf Coast region is a high potential, multi-pay province that lends itself to 3-D seismic exploration due to its substantial structural and stratigraphic complexity. In addition, certain sand reservoirs display seismic "bright spots," which can be direct hydrocarbon indicators and can result in greatly reduced drilling risk. However, "bright spots" are not always reliable as direct hydrocarbon indicators and do not generally assess reservoir productivity. We believe our established 3-D seismic exploration approach, combined with our exploration staff's extensive experience and accumulated knowledge base in this province, particularly given our historical drilling successes in this province, provides us with significant competitive advantages. We recently announced joint ventures with two operators to explore for oil and gas in Southern Louisiana. We view Southern Louisiana as a logical extension of our current activities in the upper Texas Gulf Coast that target the Frio trend.

Over the three year period ended December 31, 2005, approximately 63% of our total capital expenditures for drilling, land and seismic were allocated to our onshore Gulf Coast province where we completed 47 gross wells (30.2 net) in 53 attempts for a completion rate of 89%.

During 2005, we completed 16 gross wells (11.7 net) in 17 attempts for a completion rate of 94% in this province. We also had one well (0.8 net) that was in progress at December 31, 2005. Six of these wells were exploration, 12 were development and we operated all of the wells that we drilled in this province during 2005. For 2005, we spent $71.5 million on drilling, land and seismic in our onshore Gulf Coast province. Approximately 32% of the drilling capital spent in our onshore Gulf Coast province during 2005 was allocated to the Vicksburg trend and 68% was allocated to the Frio trend.

For 2006, we currently plan to spend a total of $78.5 million in our onshore Gulf Coast province. Approximately $65.7 million of this spending has been allocated to drilling, with the remaining $12.8 million allocated to capital spending for land and seismic activities.

Approximately $41.7 million of the drilling capital allocated to our onshore Gulf Coast province in 2006 is expected to be spent to drill 11 development wells with an average working interest of 60% and for other development activities. As of February 27, 2006, the development well that was in progress at December 31, 2005 is completing and of the 11 development wells planned for our onshore Gulf Coast province in 2006, one was completing and one well was drilling. The nine remaining development wells that we plan to drill in this province in 2006 will commence later this year.

The remaining $24 million of the total $65.7 million in drilling capital we plan to spend in our onshore Gulf Coast province in 2006 is expected to be allocated to drill nine exploration wells with an average working interest of 54%. The nine exploration wells that we plan to spud in this province in 2006 will commence drilling during the remaining three quarters of 2006.

Five of the wells we plan to drill in our Gulf Coast province are higher risk but high reserve potential wells.

Vicksburg Trend

Our Vicksburg activity is focused principally in Brooks County, Texas, in our Home Run, Triple Crown, and Floyd Fields. We discovered these fields in 1999, 2001 and 2002, respectively. In 2005, our development drilling targeting the Vicksburg was focused in our Home Run and Triple Crown Fields. During the year we completed three wells in our Triple Crown Field and two wells in our Home Run Field, at initial rates ranging from 3.3 to 10.1 MMcfe per day.

The working interests we retained in the Vicksburg wells we drilled during 2005 were higher than our historical average working interest in our Vicksburg wells. A contributing factor to this increase was our joint venture with an industry participant, where we increased our working interest to 58% from our previous 34% in the 780 acre area of mutual interest by paying the promoted drilling cost on the first well, the D.J. Sullivan C #30 during 2004. Much of our exploratory activity in the Vicksburg trend has been driven by similar joint ventures with our industry participant, which has substantial acreage holdings in the area. In addition, we continue to have discussions with our industry participant about other exploratory joint venture opportunities in the area, and expect to continue to expand our activities in the trend.

For 2006, we currently plan to spend $22 million to drill five development wells, to drill and complete wells that were in progress at December 31, 2005 and for other development activities. We expect to retain an average working interest of 65% in these development wells. As of February 27, 2006, one of these five wells was completing. The remaining four Vicksburg development wells planned for 2006 will commence drilling later in the year.

Since 1999, we have drilled twenty-nine Vicksburg wells, and we have completed 27 of those tests. We believe we have a multi-year inventory of drilling locations in our Home Run, Triple Crown and Floyd Fault Block Fields, and we expect to add to this inventory.

Frio Trend

During 2005, we drilled 12 wells that targeted the Frio, including five exploratory and seven development wells. For 2006, we currently plan to spend $25.9 million to drill four exploration wells with an average working interest of 75% and four development wells with an average working interest of 63%, to drill and complete wells that were in progress at December 31, 2005 and for other development activities. Through February 27, 2006, one of these eight wells had started drilling. The seven remaining Frio wells that we plan to drill in 2006 will commence drilling later this year.

Early in 2005, we made an apparently significant discovery with our Wyse #1, the discovery well for the Bouldin Lake Field. We operated the drilling of the Wyse #1 with a 50% working interest, with another operator participating with a 50% working interest. The Wyse #1 produced at an early rate of approximately 6.7 MMcfe per day from the Lower Frio. Approximately 90 feet of additional potential Lower Frio pay remains behind pipe for future completion. During the third quarter of 2005, the Wyse #1 was fracture stimulated, and began producing water and approximately 0.7 MMcfe per day of natural gas and condensate. We continue to evaluate various options, including but not limited to attempting to squeeze off the water producing zone or to setting a plug above the current pay intervals in order to complete the apparent pay in a shallower Lower Frio interval.

During the fourth quarter, we completed the Grisham #1, our first development well in the Bouldin Lake Field. We operated the drilling of the Grisham #1 with a 50% working interest. Subsequent to fracture stimulation of the lowest 64 feet of apparent pay, the Grisham #1 commenced production at an initial rate of approximately 7.1 MMcfe per day. An additional 30 feet of apparent pay remains behind pipe for future completion. In early February, while we were attempting to commingle the upper pay interval we discovered a problem with the casing. Operations are underway to determine the severity of the problem and we expect to reestablish production sometime in March 2006.

We currently plan to commence the drilling of the Wyse #2, in March 2006, our third well in the Bouldin Lake Field. We will operate the Wyse #2 with a 50% working interest and expect to encounter the pay intervals approximately 250 feet high to those we found in the Wyse #1 discovery well. Results for the Wyse #2 are expected in May. We currently expect to commence our fourth Bouldin Lake Field well, the Grisham #2, late in the third quarter of 2006. We will also operate the drilling of the Grisham #2 with a 50% working interest. Depending on success of the Wyse #2 and the Grisham #2, two additional wells could be drilled to fully develop the field.

Another potentially significant discovery during 2005 was our State Tract 254 #1, which generated an early production rate of approximately 6.4 MMcfe per day from a Lower Frio Anomalina interval with strong flowing casing pressures. In the same area, but in a different fault block, the Bayou Bengal B #13, after stimulation and commingling, began producing at a rate of approximately 1.5 MMcfe per day. The Bayou Bengal B #13 also encountered approximately 35 feet of apparent net pay in the shallower "F" series Frio sands, while the State Tract 254 #1 encountered comparable "F" series Frio sands with approximately 21 feet of apparent net pay. These shallower zones are currently behind pipe for future completion. In December, we commenced the State Tract 266 #1, the first offset to the Bayou Bengal B #13 and State Tract 254 #1 discoveries. The State Tract 266 #1 is the first well we have drilled to develop the shallower apparent "F" series Frio pay sands encountered in both the Bayou Bengal B #13 and the State Tract 254 #1. With success, other wells would be required to fully develop the estimated 500 acre structure.

During 2005, we drilled our first two wells in our Alamo Project, a 3-D project acquired during late 2004 and early 2005. The Imhoff #1, which encountered approximately 24 feet of apparent Lower Frio pay, and the B.K. Dillard #1, which encountered only 4 feet of apparent Lower Frio pay, both produced non-commercial oil and natural gas volumes and are currently not producing. We operated both wells with

75% working interests. We have a number of prospects identified under lease in our Alamo project and we may drill one of these during the second half of 2006.

During 2006, we currently plan to drill four wells in our General Lee Project. We acquired approximately 120 square miles of 3-D seismic data over our General Lee Project in late 2004. Three of these wells will test the largest Lower Frio structures we have mapped in the trend to date. We will operate all three tests with a 75% working interest. Two of these wells will test the Green Ranch structural complex, which covers approximately 3,000 acres. We expect to commence these wells, the Green Ranch #1 and the Green Ranch Deep #1, during the third and fourth quarters, respectively.

During the third quarter, we expect to commence drilling the Sunset Reef #1, another well in our General Lee project. This prospect covers approximately 1,500 acres and a structure that to date has produced approximately 42 Bcfe from the shallower Miocene interval. None of the wells that are productive in the shallower Miocene interval have penetrated the deeper Frio objectives.

As was the case in 2005, in 2006 we will continue to assemble new 3-D projects that add to our inventory of drilling projects in the Frio. During 2006, we expect to acquire a new proprietary 3-D seismic project in the trend, which is expected to cover approximately 50 to 100 square miles. We expect to retain a 50% working interest in this project.

Gulf Coast Louisiana Miocene and Upper Oligocene Trends

In February 2006, we announced two new joint ventures with two operators to explore and develop 3-D delineated projects that target the Miocene and upper Oligocene trends located in South Louisiana. We view these projects as a logical extension of our activities in the upper Texas Gulf Coast that target the Frio trend. In this area, we will utilize our geophysical, geological and operational expertise to explore for and develop potential reservoirs directly on trend to that of the Frio. As part of the joint ventures, we have committed to drill a minimum of three wells, at least two of which will be drilled in 2006.

In our Bayou Postillion Project located in Iberia Parish, Louisiana, we will operate the drilling of the first of these wells, the Cotten Land Corp. #1, with a 41% after casing point working interest. We expect to commence drilling the well early in the second quarter of 2006. The Cotten Land Corp. #1 directly offsets and is expected to encounter a Miocene objective, approximately 300 feet high to a recent discovery. The offsetting producer was completed in August 2005 at an initial rate of 10 MMcfe per day, and at last report continued to produce at approximately the same rate. In addition, seven wells in an adjacent fault block have produced approximately 112 Bcfe to date and are still actively producing.

In the same area, but in a different fault block, we will operate the drilling of the Cotten Land Corp. #2 with a 34% working interest. We expect to commence drilling this well in May, immediately following the Cotten Land Corp. #1. With success, two additional wells could be drilled to fully develop the area.

In our Mystic Bayou project located in St. Martin Parish, Louisiana, we will also operate the drilling of the Williams Land Company #1 well. We have identified at least three apparent fault blocks to test, all three of which are expected to encounter a Miocene objective structurally high to two wells that have combined to produce over 50 Bcfe to date. We will retain a 48% working interest in the Williams Land Company #1, which is expected to commence drilling during the third quarter of 2006.

Anadarko Basin

The Anadarko Basin is located in northwest Oklahoma and the Texas Panhandle. We believe this prolific natural gas producing province offers a combination of relatively lower risk exploration and development opportunities in shallower horizons, as well as higher risk, but higher reserve potential opportunities in the deeper sections that have been relatively under explored.

We believe our drilling programs in the Anadarko Basin and West Texas generally provide us with longer life reserves and help to balance our drilling program in the prolific, but generally shorter reserve life, onshore Gulf Coast province.

The stratigraphic and structural objectives in the Anadarko Basin can provide excellent targets for 3-D seismic imaging. In addition, drilling economics in the Anadarko Basin are enhanced by the multi-pay nature of many of these prospects, with secondary or tertiary targets serving as either incremental value or as alternatives if the primary target zone is not productive. Our recent activity has been focused primarily in the Hunton, Springer Channel and Springer Bar trends.

Over the past three years, approximately 33% of our total capital expenditures for drilling, land and seismic have been allocated to our Anadarko Basin province where we have completed 66 gross wells (22.0 net) in 68 attempts for a completion rate of 97%.

During 2005, we completed 14 gross wells (5.4 net) in 14 attempts for a completion rate of 100%. One development well (0.2 net), which commenced drilling operations prior to December 31, 2005, is currently completing. Of the wells we drilled and completed wells in 2005, four were exploration wells and ten were development wells. We operated four of the 14 wells that we drilled and completed in the Anadarko Basin in 2005.

For 2006, we currently plan to spend $44 million in our Anadarko Basin province. Approximately $32.7 million of this spending is currently allocated to drilling with the remaining $11.3 million allocated to land and seismic activities.

Approximately $29.8 million of the drilling capital allocated to our Anadarko Basin province is expected to be spent to drill ten development wells with an average working interest of 48% and for other development activities. As of February 27, 2006, of the ten development wells that we plan to drill in our Anadarko Basin province in 2006, one well was drilling. The nine remaining development wells planned for this province will commence drilling later in 2006.

The remaining $2.9 million of the total $32.7 million in drilling capital allocated to our Anadarko Basin province is expected to be spent to drill five exploration wells with an average working interest of 38%. As of February 27, 2006, none of the five exploration wells that we currently plan to drill in this province during 2006 had commenced drilling.

Of the drilling capital that we spent in our Anadarko Basin province in 2005, approximately 47% was allocated to the Hunton trend, 23% was allocated to the Springer trends and 27% was allocated to the Granite Wash trend. For 2006, approximately $19.1 million of our planned 2006 drilling expenditures that we plan to spend in our Anadarko Basin province is allocated to the Hunton trend, $5.6 million is allocated to the Springer trends and $7 million is allocated to the Granite Wash trend.

Hunton Trend

During 2005, we completed a significant development well, offsetting our late 2000 discovery well in the Mills Ranch Field. We operated the Mills Ranch #2-98 with a 100% working interest, which commenced production during the third quarter at 7.5 MMcfe per day, and subsequently produced at rates as high as 8.5 MMcfe per day. We expect to drill at least three more wells to fully develop the field, two of which are planned for 2006.

During the first quarter of 2006, we commenced operations on a reentry and sidetrack of the previously drilled Mills Ranch 99 #1S. After completing the Mills Ranch 99 #1S in the Hunton at an initial rate of approximately 8.7 MMcfe per day, production from the well declined sharply, indicating that the well was probably in a fault block that had very limited aerial extent. The Mills Ranch 99 #1S2 is an attempt to reenter this well and sidetrack out of the Mills Ranch #1-99S borehole at a depth of approximately 17,000 feet. We plan to subsequently directionally drill to a depth of approximately 21,200 feet to test the Hunton in what we expect to be an adjacent, and potentially much larger, fault block. Results are expected in the second quarter of 2006. We will retain an average working interest of 93% in the Mills Ranch 99 #1S2.

In February, we will also commence the drilling of the Mills Ranch #1-96, a development well on the westernmost end of the field. This well will offset our Mills Ranch #1-97 well, which to date has produced approximately 6 Bcfe, since coming on line in late December 2000. We expect to retain a working interest of between 63% and 80% in this well, which will target the Hunton formation at a depth of approximately 24,100 feet. Results for the Mills Ranch #1-96 are expected late in the third quarter of 2006.

Granite Wash

In the Texas panhandle of the Anadarko Basin, we drilled seven Granite Wash wells during 2005. Four of these wells were very low working interest non-operated completions. However, three of these were higher working interest operated wells that were drilled to evaluate the economics of our approximately 4,000 contiguous gross acres in Hemphill County. Adjacent acreage to this contiguous block continues to experience extensive drilling by other operators, most of which has been developed on 40 acre spacing, although some acreage is being developed on 20 acre spacing.

Our two most recent Granite Wash completions in this contiguous block, the Hobart 59-1 and the Hobart 60-3, commenced production at rates of 4.4 and 5.2 MMcfe per day subsequent to fracture stimulation, the highest rates achieved in this area by us to date. Late in 2005, we commenced the Hobart 60-4, which encountered approximately 174 feet of apparent Granite Wash pay, comparable to our two most recent completions. Production to sales for the Hobart 60-4 is expected in late February.

In February, we commenced the Hobart 59-2 with a 99% working interest. Results for this well are expected in late March. Although no additional wells in our 4,000 acre contiguous acreage block are currently planned for 2006, with continued drilling success and strong commodity prices, we could accelerate our Granite Wash drilling program in 2006. Assuming 40 acre spacing, approximately 82 additional locations could be drilled to fully develop the acreage.

West Texas

The Permian Basin of West Texas and Eastern New Mexico is a predominantly oil producing province with generally longer life reserves than that of the onshore Gulf Coast. Our drilling activity in our West Texas province has been focused primarily in various carbonate reservoirs, including the Canyon Reef and Fusselman formations of the Horseshoe Atoll trend, the Canyon Reef of the Eastern Shelf, the Wolfcamp and Devonian section of New Mexico, and the Mississippian Reef of the Hardeman Basin, at depths ranging from 7,000 to 13,000 feet.

Over the past three years, approximately 4% of our total capital expenditures for drilling, land and seismic have been allocated to our West Texas province where we have completed seven gross wells (4.2 net) in ten attempts for a completion rate of 70%.

During 2005, we completed two gross wells (2.0 net) in three attempts for a completion rate of 67%. Two of these wells were exploration, one was development and we operated all of these wells.

In total, we spent $7 million on drilling, land and seismic during 2005 in our West Texas province. For 2006, we currently plan to spend approximately $5.7 million on drilling, land and seismic. Approximately $1.4 million of this is allocated to land and seismic expenditures, $2.4 million is allocated to drill three exploration wells with an average working interest of 67% working interest and the remainder is allocated to drill one development well with an 88% working interest and for other development activities. As of February 27, 2006, of the four wells we plan to drill in our West Texas province in 2006, one had been drilled and not completed and one was currently drilling. The remaining two wells planned for our West Texas province will commence drilling later in 2006.

Given our large inventory of 3-D seismic data in West Texas and New Mexico, our strong historical results in the province and currently strong oil prices, we have begun to focus more of our resources on exploiting this asset base.

Williston Basin

Bakken

On November 1, 2005, we made a $4.6 million acquisition of approximately 46,000 net acres in the Bakken play located in 126 sections in northwestern North Dakota. We acquired a 100% working interest in the Bakken formation within the applicable oil and natural gas leases. With success, between 63 and 126 wells could be required to fully develop the acreage. Given our working interest in the sections, we expect to operate the majority of the drilling and completion operations on our acreage. The Bakken play objective in this area is an unconventional oil play at a depth of approximately 11,000 feet. We plan to drill vertical wells in this area with lateral extensions ranging from 4,000 to 9,000 feet at an estimated completed well cost of $3.5 to $4 million. This is a potential extension of ongoing Bakken activity in Richland County, Montana, located approximately 20 to 40 miles to the west. Within a 324 square mile area of Richland County, Montana, approximately 227 Bakken wells have generated average initial production rates of approximately 345 barrels of oil per day, average cumulative production to date of approximately 112,000 barrels of oil per well, and estimated ultimate recoveries of approximately 376,000 barrels of oil per well based on data compiled from external sources.

For 2006, we currently plan to spend $20.8 million on drilling, land, and seismic in our Williston Basin province. Approximately $17.7 million of this capital is allocated to drilling four pilot wells with a 100% average working interest. We will operate these four wells and currently plan to commence drilling and operate the first of these wells in the second quarter. With drilling success, the Bakken play could become a new focus trend for us.

3-D Seismic Exploration

We have accumulated 3-D seismic data covering approximately 10,710 square miles (6.9 million acres) in over 28 geologic trends in seven basins and seven states. We typically acquire 3-D seismic data in and around existing producing fields where we can benefit from the imaging of producing analog wells. These 3-D defined analogs, combined with our experience in drilling 688 wells in our 3-D project areas, provide us with a knowledge base to evaluate other potential geologic trends, 3-D seismic projects within these trends and prospective 3-D delineated drilling locations. Through our experience in the early and mid 1990's, we developed an expertise in the selection of geologic trends that we believe are best suited for 3-D seismic exploration. In 1997 and 1998 we invested approximately $64 million in 3-D seismic and land in plays that we believed were providing optimal 3-D delineated drilling economics. Since 1998, we have continued to add to our 3-D seismic database within our core trends on a more conservative pace. We have used the experience that we have gained within our core trends to enhance the quality of subsequent projects in the same trend and other analogous trends, to lower finding and development costs, to compress project cycle times and to enhance our return on capital.

Over the last 15 years, we have accumulated substantial experience exploring with 3-D seismic in a wide range of reservoir types and geologic trapping mechanisms. In addition, we typically acquire digital databases for integration on our computer-aided exploration workstations, including digital land grids, well information, log curves, production information, geologic studies, geologic top databases and existing 2-D seismic data. We use our knowledge base, local geological expertise and digital databases integrated with 3-D seismic data to create maps of producing and potentially productive reservoirs. As such, we believe our 3-D generated maps are more accurate than previous reservoir maps (which generally are based on subsurface geological information and 2-D seismic surveys), enabling us to more precisely evaluate recoverable reserves and the economic feasibility of projects and drilling locations.

Historically, we have acquired most of our raw 3-D seismic data using seismic acquisition vendors on either a proprietary basis or through alliances affording the alliance members the exclusive right to interpret and use data for extended periods of time. In addition, we have participated in non-proprietary group shoots of 3-D seismic data (commonly referred to as "spec data") when we believe the expected full cycle project economics were justified, and we have exchanged certain interests in some of our non-core proprietary seismic data to gain access to additional 3-D seismic data. In most of our proprietary 3-D data acquisitions and alliances, we have selected the sites of projects, primarily guided by our knowledge and experience in the core provinces we explore, established and monitored the seismic parameters of each project for which data was shot, and typically selected the equipment that was used.

Combining our geologic and geophysical expertise with a sophisticated land effort, we manage the majority of our projects from conception through 3-D acquisition, processing and interpretation and leasing. In addition, we manage the negotiation and drafting of virtually all of our geophysical exploration agreements, resulting in reduced contract risk and more consistent deal terms. Because we generate most of our projects, we can often control the size of the working interest that we retain as well as the selection of the operator and the non-operating participants. Consistent with our business strategy, we have increased the working interest we retain in our projects, based upon capital availability and perceived risk. Our average working interest in our 3-D seismic projects acquired during 1996, 1997 and 1998 was 37%, 67% and 80%, respectively. The 3-D seismic we acquired during 1999, 2000, 2001 and 2002 was primarily through the exchange of certain rights in some of our non-core 3-D seismic projects. Most of these exchanges did not include an industry participant, therefore we retained potentially all interest in any prospects generated from the newly acquired 3-D seismic data.

In early 2003, we acquired approximately 84 square miles of new proprietary 3-D seismic data in our General Patton Project located in the Frio trend of the Upper Texas Gulf Coast. We sold a working interest in this project to an industry participant on a promoted basis and retained a 50% working interest in the project. In 2002 and early 2003, we acquired approximately 53 square miles of non-proprietary and 56 square miles of new proprietary 3-D seismic data and purchased an ownership interest in 22 square miles of pre-existing proprietary 3-D seismic data in our Bayou Bengal project, also located in the Frio trend of the Upper Texas Gulf Coast. We sold a working interest in Bayou Bengal to an industry participant on a promoted basis and retained a 75% working interest.

During 2004, we added approximately 655 square miles of 3-D seismic data to our corporate database. Of this total, we acquired approximately 57 square miles of non-proprietary and 101 square miles of new proprietary 3-D seismic data in our Alamo project located in the Frio trend of the Upper Texas Gulf Coast. We sold a working interest in Alamo to an industry participant on a promoted basis and retained a 75% working interest in the project. Also included in the 3-D seismic data that we added to our corporate database in 2004 were approximately 120 square miles of new proprietary data we acquired in our General Lee project, which is located in the Frio trend of the Upper Texas Gulf Coast. We sold a working interest in General Lee to an industry participant on a promoted basis and retained a 75% working interest.

During 2005, we added approximately 247 square miles of 3-D seismic data to our corporate database. All 247 square miles of 3-D seismic data acquired were non-proprietary to us. Included in the 3-D seismic data that we added to our corporate database in 2005 was approximately 80 square miles of data in our Mudflats Project located in the Frio trend along the Lower Texas Gulf Coast. We retained a 100% working interest in our Mudflats project.

See "— Onshore Gulf Coast," "— Anadarko Basin," "— West Texas," and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Capital Commitments — Capital Expenditures" for additional discussion regarding our seismic capital expenditures planned for 2006.

Title to Properties

We believe we have satisfactory title, in all material respects, to substantially all of our producing properties in accordance with standards generally accepted in the oil and natural gas industry. Our properties are subject to royalty interests, standard liens incident to operating agreements, liens for current taxes and other burdens, which we believe do not materially interfere with the use of or affect the value of such properties. Substantially all of our proved oil and natural gas properties are pledged as collateral under first and second liens for borrowings under our senior credit agreement and subordinated credit agreement, respectively. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Senior Credit Agreement" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Senior Subordinated Notes."

Oil and Natural Gas Reserves

Our estimated total net proved reserves of oil and natural gas as of December 31, 2005, 2004 and 2003, pre-tax PV10% value, standardized measure and the estimated future development cost attributable to these reserves as of those dates were as follows.

	At December 31,		
	2005	2004	2003
Estimated Net Proved Reserves:			
Oil (MBbls)	3,326	3,236	4,130
Natural gas (MMcf)	113,264	101,875	109,403
Natural gas equivalent (MMcfe)	133,223	121,290	134,182
Proved developed reserves as a percentage of net proved reserves	51%	50%	50%
Pre-tax PV10% (in millions)(a)	$ 519.8	$ 294.5	$ 343.8
Standardized measure (in millions)	396.3	239.7	261.6
Estimated future development cost (in millions)	122.4	79.9	59.0
Base price used to calculate reserves(b):			
Natural gas (per MMbtu)	$ 9.44	$ 6.19	$ 5.83
Oil (per Bbl)	61.04	43.46	32.55

(a) See "— Reconciliation of Standardized Measure to Pre-tax PV10%" for a definition of pre-tax PV10% and a reconciliation of our standardized measure to our pre-tax PV10% value.

(b) These base prices were adjusted to reflect applicable transportation and quality differentials on a well-by-well basis to arrive at realized sales prices used to estimate our reserves at these dates.

The reserve estimates reflected above were prepared by Cawley, Gillespie & Associates, Inc., our independent petroleum consultants, and are part of reports on our oil and natural gas properties prepared by them.

In accordance with applicable requirements of the Securities and Exchange Commission (SEC), estimates of our net proved reserves and future net revenues are made using sales prices estimated to be in effect as of the date of such reserve estimates and are held constant throughout the life of the properties (except to the extent a contract specifically provides for escalation). Estimated quantities of net proved reserves and future net revenues there from are affected by oil and natural gas prices, which have fluctuated widely in recent years. There are numerous uncertainties inherent in estimating oil and natural gas reserves and their estimated values, including many factors beyond our control. The reserve data set forth in the Cawley, Gillespie & Associates, Inc. report represents only estimates. Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geologic interpretation and judgment. As a result, estimates of different engineers, including those used by us, may vary. In addition, estimates of reserves are subject to revision based upon actual production, results of future development and exploration activities, prevailing oil and natural gas prices, operating costs and other factors. The revisions may be material. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered and are highly dependent upon the accuracy of the assumptions upon which they are based. Our estimated net proved reserves, included in our Security and Exchange Commission filings, have not been filed with or included in reports to any other federal agency. See "Item 1A. Risk Factors — Although our oil and gas reserve data is independently estimated, these estimates may still prove to be inaccurate."

Estimates with respect to net proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations in the estimated reserves that may be substantial.

Reconciliation of Standardized Measure to Pre-tax PV10%

Pre-tax PV10% is the estimated present value of the future net revenues from our proved oil and natural gas reserves before income taxes discounted using a 10% discount rate. Pre-tax PV10% is considered a non-GAAP financial measure under SEC regulations because it does not include the effects of future income taxes, as is required in computing the standardized measure of discounted future net cash flows. We believe that Pre-tax PV10% is an important measure that can be used to evaluate the relative significance of our oil and natural gas properties and that Pre-tax PV10% is widely used by security analysts and investors when evaluating oil and natural gas companies. Because many factors that are unique to each individual company impact the amount of future income taxes to be paid, the use of a pre-tax measure provides greater comparability of assets when evaluating companies. We believe that most other companies in the oil and natural gas industry calculate Pre-tax PV10% on the same basis. Pre-tax PV10% is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting income taxes. The table below provides a reconciliation of our standardized measure of discounted future net cash flows to our Pre-tax PV10% value.

	At December 31,		
	2005	2004	2003
Standardized measure of discounted future net cash flows	$396.3	$239.7	$261.6
Add present value of future income tax discounted at 10%	123.5	54.8	82.2
Pre-tax PV10%	$519.8	$294.5	$343.8

Drilling Activities

We drilled, or participated in the drilling of, the following number of wells during the periods indicated.

	Year Ended December 31,					
	2005(a)		2004(b)		2003	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Natural gas	8	4.5	10	5.4	14	6.8
Oil	0	0.0	1	0.9	4	1.3
Non-productive	4	3.5	7	5.2	4	1.8
Total	12	8.0	18	11.5	22	9.9
Development wells:						
Natural gas	17	9.4	35	13.9	11	3.9
Oil	2	1.1	2	0.3	1	0.4
Non-productive	3	2.2	5	1.5	3	1.8
Total	22	12.7	42	15.7	15	6.1

(a) Excludes two (1.0 net) development wells that are currently completing.

(b) Includes one (1.0 net) exploratory well that commenced drilling in 2004 and was completed productive in 2005.

We do not own drilling rigs and all of our drilling activities have been conducted by independent contractors or by industry participant operators under standard drilling contracts.

Productive Wells and Acreage

Productive Wells

The following table sets forth our ownership interest at December 31, 2005 in productive oil and natural gas wells in the areas indicated. Wells are classified as oil or natural gas according to their predominant production stream. Gross wells are the total number of producing wells in which we have an interest, and net wells are determined by multiplying gross wells by our average working interest.

	Natural Gas		Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
Onshore Gulf Coast	63	30.7	23	6.1	86	36.8
Anadarko Basin	167	37.7	22	4.3	189	42.0
West Texas and other	14	1.9	74	23.4	88	25.3
Total	244	70.3	119	33.8	363	104.1

Productive wells consist of producing wells and wells capable of production, including wells waiting on pipeline connection. Wells that are completed in more than one producing horizon are counted as one well. Of the gross wells reported above, three had multiple completions.

Acreage

Undeveloped acreage includes leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether or not such acreage contains proved reserves. The following table sets forth the approximate developed and undeveloped acreage that we held a leasehold interest in at December 31, 2005.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Onshore Gulf Coast	17,172	8,091	32,162	22,389	49,334	30,480
Anadarko Basin	56,707	23,138	23,374	15,134	80,081	38,272
West Texas	15,834	5,052	8,682	7,957	24,516	13,009
Other	3,041	1,284	48,417	48,030	51,458	49,314
Total	92,754	37,565	112,635	93,510	205,389	131,075

In addition, as of December 31, 2005, we owned 2,421 gross and 1,837 net mineral acres.

All of our leases for undeveloped acreage summarized in the preceding table will expire at the end of their respective primary terms unless we renew the existing leases, we establish production from the acreage, or some other "savings clause" is implicated. The following table sets forth the minimum remaining leases terms for our gross and net undeveloped acreage.

	Acres Expiring	
Twelve Months Ending:	Gross	Net
December 31, 2006	17,491	10,296
December 31, 2007	15,958	11,005
December 31, 2008	27,560	23,565
Thereafter	51,626	48,644
Total	112,635	93,510

In addition, as of December 31, 2005, we had lease options and rights of first refusal to acquire additional acres. The following table sets forth the expiration year of our options and right of first refusal agreements and our gross and net acres associated with those options and agreements.

	Acres Expiring	
Twelve Months Ending:	Gross	Net
December 31, 2006	53,446	50,505

Volumes, Prices and Production Costs

The following table sets forth our production volumes, the average prices we received before hedging, the average prices we received after hedging and average production costs associated with our sale of oil and natural gas for the periods indicated.

	Year Ended December 31, 2005	2004	2003
Production:			
Oil (MBbls)	450	573	720
Natural gas (MMcf)	9,213	8,830	6,356
Natural gas equivalent (MMcfe)	11,913	12,265	10,674
Average sales price per unit:			
Oil revenues (per Bbl)	$ 54.73	$ 40.13	$ 30.79
Effects of hedging activities (per Bbl)	(2.78)	(4.96)	(2.62)
Average price (per Bbl)	$ 51.95	$ 35.17	$ 28.17
Natural gas revenues (per Mcf)	$ 8.29	$ 6.05	$ 5.68
Effects of hedging activities (per Mcf)	(0.32)	(0.21)	(0.76)
Average price (per Mcf)	$ 7.97	$ 5.84	$ 4.92
Total oil and natural gas revenues (per Mcfe)	$ 8.48	$ 6.23	$ 5.46
Effects of hedging activities (per Mcfe)	(0.35)	(0.38)	(0.63)
Average price (per Mcfe)	$ 8.13	$ 5.85	$ 4.83
Average production costs (per Mcfe):			
Lease operating expenses (includes costs for operating and maintenance and expensed workovers)	$ 0.51	$ 0.43	$ 0.43
Ad valorem taxes	0.09	0.07	0.06
Production taxes	0.28	0.25	0.23

Item 3. ***Legal Proceedings***

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

As of December 31, 2005, there are no known environmental or other regulatory matters related to our operations that are reasonably expected to result in a material liability to us. Compliance with environmental laws and regulations has not had, and is not expected to have, a material adverse effect on our capital expenditures.

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

No matter was submitted to a vote of our security holders during the fourth quarter of 2005.

Executive Officers of the Registrant

Pursuant to Instruction 3 to Item 401(b) of the Regulation S-K and General Instruction G(3) to Form 10-K, the following information is included in Part I of this report. The following are our executive officers as of February 27, 2006.

Name	Age	Position
Ben M. Brigham	46	Chief Executive Officer, President and Chairman
Eugene B. Shepherd, Jr.	47	Executive Vice President and Chief Financial Officer
David T. Brigham	45	Executive Vice President — Land and Administration and Director
A. Lance Langford	43	Executive Vice President — Operations
Jeffery E. Larson	47	Executive Vice President — Exploration

Ben M. "Bud" Brigham has served as our Chief Executive Officer, President and Chairman of the Board since we were founded in 1990. From 1984 to 1990, Mr. Brigham served as an exploration geophysicist with Rosewood Resources, an independent oil and gas exploration and production company. Mr. Brigham began his career in Houston as a seismic data processing geophysicist for Western Geophysical, Inc. a provider of 3-D seismic services, after earning his B.S. in Geophysics from the University of Texas at Austin. Mr. Brigham is the brother of David T. Brigham, Executive Vice President — Land and Administration.

Eugene B. Shepherd, Jr. has served as Executive Vice President and Chief Financial Officer since October 2003, and previously served as Chief Financial Officer from June 2002 to October 2003. Mr. Shepherd has approximately 23 years of financial and operational experience in the energy industry. Prior to joining us, Mr. Shepherd served as Integrated Energy Managing Director for the investment banking division of ABN AMRO Bank, where he executed merger and acquisition advisory, capital markets and syndicated loan transactions for energy companies. Prior to joining ABN AMRO, Mr. Shepherd spent fourteen years as an investment banker for Prudential Securities Incorporated, Stephens Inc. and Merrill Lynch Capital Markets. Mr. Shepherd worked as a petroleum engineer for over four years for both Amoco Production Company and the Railroad Commission of Texas. He holds a B.S. in Petroleum Engineering and an MBA, both from the University of Texas at Austin.

David T. Brigham joined us in 1992 and has served as a Director since May 2003 and as Executive Vice President — Land and Administration since June 2002. Mr. Brigham served as Senior Vice President — Land and Administration from March 2001 to June 2002, Vice President — Land and Administration from February 1998 to March 2001, as Vice President — Land and Legal from 1994 until February 1998 and as Corporate Secretary from February 1998 to September 2002. From 1987 to 1992, Mr. Brigham was an oil and gas attorney with Worsham, Forsythe, Sampels & Wooldridge. Before attending law school, Mr. Brigham was a landman for Wagner & Brown Oil and Gas Producers, an independent oil and gas exploration and production company. Mr. Brigham holds a B.B.A. in Petroleum Land Management from the University of Texas and a J.D. from Texas Tech School of Law. Mr. Brigham is the brother of Ben M. Brigham, Chief Executive Officer, President and Chairman of the Board.

A. Lance Langford joined us in 1995 as Manager of Operations and served as Vice President — Operations from January 1997 to March 2001, served as Senior Vice President — Operations from March 2001 to September 2003 and has served as Executive Vice President — Operations since September 2003. From 1987 to 1995, Mr. Langford served in various engineering capacities with Meridian Oil Inc., handling a variety of reservoir, production and drilling responsibilities. Mr. Langford holds a B.S. in Petroleum Engineering from Texas Tech University.

Jeffery E. Larson joined us in 1997 and was Vice President — Exploration from August 1999 to March 2001, Senior Vice President — Exploration from March 2001 to September 2003 and has served as Executive Vice President — Exploration since September 2003. Prior to joining us, Mr. Larson was an explorationist in the Offshore Department of Burlington Resources, a large independent exploration company, where he was responsible for generating exploration and development drilling opportunities. Mr. Larson worked at Burlington from 1990 to 1997 in various roles of responsibility. Prior to Burlington, Mr. Larson spent five years at Exxon as a Production Geologist and Research Scientist. He holds a B.S. in Earth Science from St. Cloud State University in Minnesota and a M.S. in Geology from the University of Montana.

PART II

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

Price Range of Common Stock and Dividend Policy

Our common stock commenced trading on the NASDAQ National Market on May 8, 1997 under the symbol "BEXP." The following table sets forth the high and low intra-day sales prices per share of our common stock for the periods indicated on the Nasdaq National Market for the periods indicated. The sales information below reflects inter-dealer prices, without retail mark-ups, mark-downs or commissions and may not necessarily represent actual transactions.

	High	Low
2004:		
First Quarter	$ 8.63	$ 6.60
Second Quarter	10.04	7.34
Third Quarter	9.89	7.56
Fourth Quarter	10.05	7.72
2005:		
First Quarter	$ 9.83	$ 7.60
Second Quarter	9.65	7.10
Third Quarter	13.42	7.80
Fourth Quarter	14.68	11.35

The closing market price of our common stock on February 27, 2006 was $8.70 per share. As of February 27, 2006, there were an estimated 172 record owners of our common stock.

No dividends have been declared or paid on our common stock to date. We intend to retain all future earnings for the development of our business. Our senior credit agreement, subordinated credit agreement and Series A preferred stock restrict our ability to pay dividends on our common stock.

We are obligated to pay dividends on our Series A preferred stock. At our option, these dividends were paid in kind through the issuance of additional shares of preferred stock in lieu of cash at a rate of 8% per annum through September 2005. Starting in October 2005, all dividends related to our series A preferred stock are required to be paid in cash at a rate of 6% per annum. "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Capital Commitments — Mandatorily Redeemable Preferred Stock."

Securities Authorized for Issuance under Equity Compensation Plans

The following table includes information regarding our equity compensation plans as of the year ended December 31, 2005.

Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options	Weighted-Average Price of Outstanding Options	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans
Equity compensation plans approved by security holders(a)	2,946,333	$6.96	1,344,000
Equity compensation plans not approved by security holders	—	—	—
Total	2,946,333	$6.96	1,344,000

(a) Does not include 397,650 shares of restricted stock at December 31, 2005.

Issuer Purchases of Equity Securities

In 2005, 2004 and 2003 we elected to allow employees to deliver shares of vested restricted stock with a fair market value equal to their federal, state and local tax withholding amounts on the date of issue in lieu of cash payment. Furthermore, in November and December 2005, pursuant to a stock purchase agreement, we used the net proceeds from a sale of our common stock to purchase 6,125,000 shares of our common stock held by merchant banking funds managed by affiliates of CSFB Private Equity.

Period	Total Number of Shares Purchased	Average Price Paid per Share
December 2005	1,125,000	$11.460
November 2005	5,000,000	11.460
January 2005	21,229	8.930
October 2004	15,790	9.205
January 2004	19,596	7.970
October 2003	16,351	6.705

Recent Issuance of Unregistered Securities

Common Stock

All shares of common stock issued in the following transactions were exempted from registration under section 4(2) of the Securities Act of 1933.

In February 2003, we issued 248,028 unregistered shares of our common stock. The common stock was issued in connection with a cashless exercise of warrants to purchase 487,805 shares of our common stock for $2.5625 per share. We received no proceeds from the warrant exercise. The warrants exercised represented a portion of the warrants that were issued in connection with our sale of 731,707 shares of our common stock in February 2000 to a group of institutional investors. This group of investors was led by affiliates of two members of our then current Board of Directors. At the time the warrants were exercised, one of these two board members was no longer a member of our board.

In June 2003, we issued 408,928 unregistered shares of our common stock to the Bank of Montreal. The common stock was issued to the Bank of Montreal in connection with its cashless exercise of warrants to purchase 661,538 shares of our common stock for $2.02 per share. We received no proceeds from the warrant exercise. The warrants were issued as consideration for an amendment to a previous senior credit agreement in July 1999. The original warrant exercise price of $2.25 per share was reset to $2.02 in February 2000 in connection with an amendment to a previous senior credit agreement. The Bank of Montreal subsequently sold these shares in our common stock sale in September 2003. We received no proceeds from the subsequent sale of the common stock.

In June 2003, we issued 206,982 unregistered shares of our common stock to Société Générale. The common stock was issued to Société Générale in connection with its cashless exercise of warrants to purchase 338,462 shares of our common stock for $2.02 per share. We received no proceeds from the warrant exercise. The warrants were issued as consideration for an amendment to a previous senior credit agreement in July 1999. The original warrant exercise price of $2.25 per share was reset to $2.02 in February 2000 in connection with an amendment to a previous senior credit agreement. Société Générale subsequently sold these shares in our common stock sale in September 2003. We received no proceeds from the subsequent sale of the common stock.

In November 2003, we issued 6,666,667 unregistered shares of our common stock to CSFB Private Equity. The common stock was issued to CSFB Private Equity in connection with its exercise of warrants to purchase 6,666,667 shares of our common stock for $3.00 per share. Pursuant to the warrant agreement, we required CSFB Private Equity to exercise the warrants as the average price of our common stock closed above $5.00 per share each day for 60 consecutive days. CSFB Private Equity elected to use 1,000,002 shares of Series A preferred stock to pay the $20 million exercise price. The warrants were issued in connection with our sale of $20 million of Series A — Tranche 1 preferred stock to CSFB Private Equity in November 2000.

In December 2003, we issued 2,105,263 unregistered shares of our common stock to CSFB Private Equity. The common stock was issued to CSFB Private Equity in connection with its exercise of warrants to purchase 2,105,263 shares of our common stock for $4.35 per share. The original exercise price for the warrants was $4.75, but was reset in December 2002, in connection with the issuance of our Series B preferred stock. Pursuant to the warrant agreement, we required CSFB Private Equity to exercise the warrants as our stock price averaged at least $6.525 (150% of the exercise price of the warrants) for 60 consecutive trading days. CSFB Private Equity elected to use 457,898 shares of Series A preferred stock to pay the $9.2 million exercise price and we received no proceeds from the warrant exercise. The warrants were issued in connection with our sale of $10 million of Series A — Tranche 2 preferred stock to CSFB Private Equity in March 2001.

In December 2003, we issued 2,298,850 unregistered shares of our common stock to CSFB Private Equity. The common stock was issued to CSFB Private Equity in connection with its exercise of warrants to purchase 2,298,850 shares of our common stock for $4.35 per share. Pursuant to the warrant agreement, we required CSFB Private Equity to exercise the warrants as our stock price averaged at least $6.525 (150% of the exercise price of the warrants) for 60 consecutive trading days. CSFB Private Equity elected to use 500,002 shares of Series B preferred stock to pay the $10 million exercise price and we received no proceeds from the warrant exercise. The warrants were issued in connection with our sale of $10 million of Series B preferred stock to CSFB Private Equity in December 2002. See "— Mandatorily Redeemable Preferred Stock."

Mandatorily Redeemable Preferred Stock

All shares of manditorily redeemable preferred stock issued in the following transactions were exempted from registration under Section 4(2) of the Securities Act of 1933.

As of December 31, 2005, we had 505,051 shares of mandatorily redeemable Series A preferred stock outstanding, that was held by merchant banking funds managed by affiliates of CSFB Private Equity. From issuance through September 2005, we paid the dividends on our Series A preferred stock in kind through the issuance of additional shares of preferred stock at a rate of 8% per annum. Beginning in October 2005, we paid all dividend obligations related to our Series A preferred stock in cash at a rate of 6% per annum. We are required to pay cash dividends on our preferred stock until it matures in October 2010 or until it is redeemed. Our Series A preferred stock is redeemable at our option at 100% or 101% of the stated value per share (depending upon certain conditions) at anytime prior to maturity.

In December 2002, we issued to CSFB Private Equity 500,000 shares of our Series B preferred stock with a stated value of $20.00 per share. Net proceeds from the offering were $9.4 million and were used to reduce borrowings under our senior credit agreement and to fund our drilling program and working capital requirements. The Series B preferred stock had terms similar to our previously issued Series A preferred stock. We were required to pay dividends on our Series B preferred stock at a rate of 6% per annum if paid in cash or 8% per annum if paid in kind through the issuance of additional shares of preferred stock in lieu of cash. Our option to pay dividends in kind would have expired in December 2007. In connection with the issuance of the Series B preferred stock, we issued to CSFB Private Equity warrants to purchase 2,298,851 shares of our common stock at an exercise price of $4.35 per share. To exercise the warrants, CSFB Private Equity had the option to use either cash or shares of our Series B preferred stock with an aggregate value equal to the exercise price. In December 2003, CSFB Private Equity elected to use 500,002 shares of Series B preferred stock to pay the $10 million warrant exercise price. See "— Common Stock." In addition, pursuant to the terms of the Series B preferred stock we paid CSFB Private Equity approximately $704,000 to redeem the shares of Series B preferred stock that remained outstanding after the exercise. In June 2004, we filed a Certificate of Elimination to eliminate our Series B preferred stock.

Item 6. *Selected Consolidated Financial Data*

This section presents our selected consolidated financial data and should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements and related notes included in "Item 8. Financial Statements and Supplementary Data." The selected consolidated financial data in this section is not intended to replace our consolidated financial statements.

We derived the statement of operations data and statement of cash flows data for the years ended December 31, 2005, 2004 and 2003, and balance sheet data as of December 31, 2005 and 2004 from the audited consolidated financial statements included in this report. We derived the statement of operations data and statement of cash flows data for the years ended December 31, 2002 and 2001 and the balance sheet data as of December 31, 2003, 2002 and 2001, from our accounting books and records.

	Year Ended December 31,				
	2005	2004	2003	2002	2001
	(In thousands, except per share information)				
Statement of Operations Data:					
Oil and natural gas sales	$ 96,820	$ 71,713	$51,545	$35,100	$32,293
Other revenues	220	515	132	76	255
Total revenues	97,040	72,228	51,677	35,176	32,548
Lease operating expenses	7,161	6,173	5,200	3,759	3,486
Production taxes	3,353	3,107	2,477	1,977	1,511
General and administrative expenses	5,533	5,392	4,500	4,971	3,638
Depletion of oil and natural gas properties	33,268	23,844	16,819	14,694	13,225
Depreciation and amortization	762	722	629	440	677
Accretion of discount on asset retirement obligations	180	159	142	—	—
Total costs and expenses	50,257	39,397	29,767	25,841	22,537
Operating income	46,783	32,831	21,910	9,335	10,011
Other income (expense)					
Interest expense, net	(3,980)	(3,144)	(4,815)	(6,238)	(6,681)
Interest income	245	84	45	119	264
Other income (expense)	(576)	742	(601)	(310)	8,080
Debt conversion expense	—	—	—	(630)	—
Total other income (expense)	(4,311)	(2,318)	(5,371)	(7,059)	1,663
Income before income taxes and cumulative effect of change in accounting principle	$ 42,472	$ 30,513	$16,539	$ 2,276	$11,674
Income tax benefit (expense)	(15,037)	(10,863)	1,223	—	—
Income before cumulative effect of change in accounting principle	27,435	19,650	17,762	2,276	11,674
Cumulative effect of change in accounting principle	—	—	268	—	—
Net income	27,435	19,650	18,030	2,276	11,674
Preferred dividend and accretion	—	—	3,448	2,952	2,450
Net income (loss) available to common stockholders	$ 27,435	$ 19,650	$14,582	$ (676)	$ 9,224
Earnings (loss) per share before cumulative effect of change in accounting principle					
Basic	$ 0.65	$ 0.49	$ 0.62	$ (0.04)	$ 0.58
Diluted	0.63	0.47	0.51	(0.04)	0.44
Earnings (loss) per share					
Basic	$ 0.65	$ 0.49	$ 0.63	$ (0.04)	$ 0.58
Diluted	0.63	0.47	0.52	(0.04)	0.44
Weighted average shares outstanding					
Basic	42,481	40,445	23,363	16,138	15,988
Diluted	43,728	41,616	34,354	16,138	28,205

	At December 31,				
	2005	2004	2003	2002	2001
	(In thousands)				
Statement of Cash Flows Data:					
Net cash provided (used) by:					
Operating activities	$ 64,379	$56,381	$41,691	$28,973	$18,922
Investing activities	(113,220)	(84,645)	(46,089)	(27,206)	(33,571)
Financing activities	50,535	24,766	(5,141)	8,439	18,924
Balance Sheet Data:					
Cash and cash equivalents	$ 3,975	$ 2,281	$ 5,779	$15,318	$ 5,112
Oil and natural gas properties, using the full cost method of accounting, net	347,329	261,979	198,490	166,006	153,017
Total assets	380,427	286,307	224,982	203,085	174,201
Long-term debt	63,100	41,000	39,000	81,797	91,721
Series A preferred stock, mandatorily redeemable	10,101	9,520	8,794	19,540	16,614
Series B preferred stock, mandatorily redeemable	—	—	—	4,777	—
Total stockholders' equity	241,640	183,276	139,111	62,775	50,727

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

Statements in the following discussion may be forward-looking and involve risk and uncertainty. The following discussion should be read in conjunction with our Consolidated Financial Statements and Notes hereto.

Overview of Our Business

We are an independent exploration and production company that applies 3-D seismic imaging and other advanced technologies to systematically explore for and develop onshore oil and natural gas reserves in the United States. Our activities are concentrated in the onshore Gulf Coast, the Anadarko Basin and West Texas, which are areas with known hydrocarbon resources and are conducive to multi-well, repeatable drilling programs and the skills of our technical staff. We also regularly evaluate opportunities to expand our activities to other areas that may offer attractive exploration and development potential, with a particular interest in those plays that complement our current exploration, development and production activities. As a result, we recently announced the acquisition of acreage in the Bakken play in North Dakota and announced joint ventures with two operators in Southern Louisiana.

Our principal business is the generation of drilling prospects in our core provinces, the drilling of those prospects and, if successful, the subsequent completion and production of the resulting oil or natural gas well. We do not have a history of aggressively competing for acquisition opportunities, although we regularly review such opportunities. We believe that we can achieve a better and more predictable rate of return by focusing our activities on prospect generation, drilling and producing activities.

Critical Accounting Policies

The establishment and consistent application of accounting policies is a vital component of accurately and fairly presenting our consolidated financial statements in accordance with generally accepted accounting principles (GAAP), as well as ensuring compliance with applicable laws and regulations governing financial reporting. While there are rarely alternative methods or rules from which to select in establishing accounting and financial reporting policies, proper application often involves significant judgment regarding a given set of facts and circumstances and a complex series of decisions.

Use of Estimates

The preparation of financial statements in accordance with GAAP in the United States of America requires us to make estimates and assumptions that affect our reported assets, liabilities, revenues, expenses, and some narrative disclosures. Our estimates of our proved oil and natural gas reserves, future development costs, production expense, revenue and deferred income taxes are the most critical to our financial statements.

Oil and Natural Gas Reserves

The determination of depreciation, depletion and amortization expense as well as impairments that are recognized on our oil and natural gas properties are highly dependent on the estimates of the proved oil and natural gas reserves attributable to our properties. Our estimate of proved reserves is based on the quantities of oil and natural gas which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in the future years from known reservoirs under existing economic and operating conditions. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation, and judgment. For example, we must estimate the amount and timing of future operating costs, severance taxes and development costs, all of which may in fact vary considerably from actual results. In addition, as the prices of oil and natural gas and cost levels change from year to year, the economics of producing our reserves may change and therefore the estimate of proved reserves may also change. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves.

The information regarding present value of the future net cash flows attributable to our proved oil and natural gas reserves are estimates only and should not be construed as the current market value of the estimated oil and natural gas reserves attributable to our properties. Thus, such information includes revisions of certain reserve estimates attributable to our properties included in the prior year's estimates. Such revisions reflect additional information from subsequent activities, production history of the properties involved and any adjustments in the projected economic life of such properties resulting from changes in oil and natural gas prices. Any future downward revisions could adversely affect our financial condition, our borrowing ability, our future prospects and the value of our common stock.

The estimates of our proved oil and natural gas reserves used in the preparation of our consolidated financial statements were prepared by Cawley, Gillespie & Associates, Inc., our independent petroleum consultants, and were prepared in accordance with the rules promulgated by the SEC.

Oil and Natural Gas Property

The method of accounting we use to account for our oil and natural gas investments determines what costs are capitalized and how these costs are ultimately matched with revenues and expensed.

We utilize the full cost method of accounting to account for our oil and natural gas investments instead of the successful efforts method because we believe it more accurately reflects the underlying economics of our programs to explore and develop oil and natural gas reserves. The full cost method embraces the concept that dry holes and other expenditures that fail to add reserves are intrinsic to the oil and natural gas exploration business. Thus, under the full cost method, all costs incurred in connection with the acquisition, development and exploration of oil and natural gas reserves are capitalized. These capitalized amounts include the costs of unproved properties, internal costs directly related to acquisitions, development and exploration activities, asset retirement costs, geological and geophysical costs and capitalized interest. Although some of these costs will ultimately result in no additional reserves, they are part of a program from which we expect the benefits of successful wells to more than offset the costs of any unsuccessful ones. The full cost method differs from the successful efforts method of accounting for oil and natural gas investments. The primary differences between these two methods are the treatment of exploratory dry hole costs. These costs are generally expensed under the successful efforts method when it is determined that measurable reserves do not exist. Geological and geophysical costs are also expensed under the successful efforts method. Under the full cost method, both dry hole costs and geological and geophysical costs are initially capitalized and classified as unevaluated properties pending determination of proved reserves. If no proved reserves are discovered, these costs are then amortized with all the costs in the full cost pool.

Capitalized amounts except unevaluated costs are depleted using the units of production method. The depletion expense per unit of production is the ratio of the sum of our unamortized historical costs and estimated future development costs to our proved reserve volumes. Estimation of hydrocarbon reserves relies on professional judgment and use of factors that cannot be precisely determined. Subsequent reserve estimates materially different from those reported would change the depletion expense recognized during the future reporting periods. For the year ended December 31, 2005, our weighted average depletion expense per unit of production was $2.79 per Mcfe. A 10% decrease in our estimated net proved reserves at December 31, 2005, would result in a $0.35 per Mcfe increase in our per unit depletion expense and a $4.2 million decrease in our pre-tax net income.

To the extent the capitalized costs in our full cost pool (net of depreciation, depletion and amortization and related deferred taxes) exceed the sum of the present value (using a 10% discount rate and based on period-end hedge adjusted oil and natural gas prices) of the estimated future net cash flows from our proved oil and natural gas reserves and the capitalized cost associated with our unproved properties, we would have a capitalized ceiling impairment. Such costs would be charged to operations as a reduction of the carrying value of oil and natural gas properties. The risk that we will be required to write down the carrying value of our oil and natural gas properties increases when oil and natural gas prices are depressed, even if the low prices are temporary. In addition, capitalized ceiling impairment charges may occur if we experience poor drilling results or estimations of our proved reserves are substantially reduced.

A capitalized ceiling impairment is a reduction in earnings that does not impact cash flows, but does impact operating income and stockholders' equity. Once recognized, a capitalized ceiling impairment charge to oil and natural gas properties cannot be reversed at a later date. No assurance can be given that we will not experience a capitalized ceiling impairment charge in future periods. In addition, capitalized ceiling impairment charges may occur if estimates of proved hydrocarbon reserves are substantially reduced or estimates of future development costs increase significantly. See "Item 1A. Risk Factors — Exploratory Drilling is a speculative activity that may not result in commercially productive reserves and may require expenditures in excess of budgeted amounts," "Item 1A. Risk Factors — We need to replace our reserves at a faster rate than companies whose reserves have longer production periods. Our failure to replace our reserves would result in decreasing reserves and production over time" and "Item 1A. Risk Factors — Lower oil and natural gas prices may cause us to record ceiling limitation write-downs, which would reduce our stockholders' equity."

Asset Retirement Obligations

We have significant obligations to plug and abandon our oil and natural gas wells and related equipment. Liabilities for asset retirement obligations are recorded at fair value in the period incurred. The related asset value is increased by the same amount. Asset retirement costs included in the carrying amount of the related asset are subsequently allocated to expense as part of our depletion calculation. See "— Oil and Natural Gas Property." Additionally, increases in the discounted asset retirement liability resulting from the passage of time are reported as accretion of discount on asset retirement obligations expense on our Consolidated Statement of Income.

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

Income Taxes

Deferred tax assets are recognized for temporary differences in financial statement and tax basis amounts that will result in deductible amounts and carry-forwards in future years. Deferred tax liabilities are recognized for temporary differences that will result in taxable amounts in future years. Deferred tax assets and liabilities are measured using enacted tax law and tax rate(s) for the year in which we expect the temporary differences to be deducted or settled. The effect of a change in tax law or rates on the valuation of deferred tax assets and liabilities is recognized in income in the period of enactment. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

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

We have a significant deferred tax asset associated with net operating loss carryforwards (NOLs). It is more likely than not that we will use these NOLs to offset current tax liabilities in future years. Our NOLs are more fully described in "Item 8. Financial Statements and Supplementary Data — Note 7."

Revenue Recognition

We derive revenue primarily from the sale of the oil and natural gas we produce, hence our revenue recognition policy for these sales is significant.

We recognize revenue from the sale of oil using the sales method of accounting. Under this method, we recognize revenue when we deliver oil and title transfers.

We recognize revenue from the sale of natural gas using the entitlements method of accounting. Under this method, we recognize revenue based on our entitled ownership percentage of sales of natural gas delivered to purchasers. Gas imbalances occur when we sell more or less than our entitled ownership percentage of total natural gas production. When we receive less than our entitled share, a receivable is recorded. When we receive more than our entitled share, a liability is recorded.

Settlements for hydrocarbon sales can occur up to two months after the end of the month in which the oil, natural gas or other hydrocarbon products were produced. We estimate and accrue for the value of these sales using information available to us at the time our financial statements are generated. Differences are reflected in the accounting period that payments are received from the purchaser.

Derivative Instruments and Hedging Activities

We use derivative instruments to manage our market risks associated with fluctuations in oil and natural gas prices. We periodically enter into derivative contracts, including price swaps, caps and floors, which require payments to (or receipts from) counterparties based on the differential between a fixed price and a variable price for a fixed quantity of oil and natural gas without the exchange of underlying volumes. The notional amounts of these financial instruments are based on expected production from existing wells.

We similarly use derivative contracts to manage our risks associated with interest rate fluctuations on long term debt. During 2003, we entered into an interest rate swap to convert the floating interest rate on our senior subordinated notes to a fixed interest rate to reduce our exposure to potentially higher interest rates in the future. The notional amount of this contract is $20 million, and is more fully described in "Item 8. Financial Statements and Supplementary Data — Note 10."

In accordance with FASB requirements SFAS 133, as amended, all our derivative contracts are reported on our balance sheet at fair value and period to period changes in the fair value of the contracts are reported each period in current earnings or other comprehensive income, depending on whether a contract has been designated as a hedge transaction, and depending on the type of hedge transaction. Our derivative contracts, designated as hedge transaction, are cash flow hedge transactions in which we are hedging the variability of cash flow related to a forecasted transaction. Period to period changes in the fair value of these derivative contracts are reported as other comprehensive income and are reclassified as earnings in the period(s) in which earnings are impacted by the variability of the cash flow of the hedged item. We assess the effectiveness of hedging transactions every three months, consistent with our documented risk management strategy for the particular hedging relationship. Changes in the fair value of the ineffective portion of cash flow hedges are included in earnings.

New Accounting Pronouncement

In December 2004, the FASB issued Statement of Financial Accounting Standards No. 123R (SFAS 123R) "Share-Based Payment." SFAS 123R is a revision of SFAS 123, "Accounting for Stock Based Compensation," and supersedes APB 25. Among other items, SFAS 123R eliminates the use of APB 25 and the intrinsic value method of accounting, and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments, based on the grant date fair value of those awards, in the financial statements. Pro forma disclosure is no longer an alternative under the new standard. We adopted SFAS 123R January 1, 2006, using the modified prospective method.

SFAS 123R permits companies to adopt its requirements using either a "modified prospective" method, or a "modified retrospective" method. Under the "modified prospective" method, compensation cost is recognized in the financial statements beginning with the effective date, based on the requirements of SFAS 123R for all share-based payments granted after that date, and based on the requirements of SFAS 123 for all unvested awards granted prior to the effective date of SFAS 123R. Under the "modified retrospective" method, the requirements are the same as under the "modified prospective" method, but also permit entities to restate financial statements of previous periods based on proforma disclosures made in accordance with SFAS 123.

We currently utilize the Black-Scholes option pricing model to measure the fair value of stock options granted to employees and directors. While SFAS 123R permits entities to continue to use such a model, the standard also permits the use of a more complex binomial, or "lattice" model. Based upon the type and number of stock options expected to be issued in the future, we have determined that we will continue to use the Black-Scholes model for option valuation as of the current time.

SFAS 123R includes several modifications to the way that income taxes are recorded in the financial statements. The expense for certain types of option grants is only deductible for tax purposes at the time that the taxable event takes place, which could cause variability in our effective tax rates recorded throughout the year. SFAS 123R does not allow companies to "predict" when these taxable events will take place. Furthermore, it requires that the benefits associated with the tax deductions in excess of recognized compensation cost be reported as a financing cash flow. These future amounts cannot be estimated, because they depend on, among other things, when the stock options are exercised.

Subject to a complete review of the requirements of SFAS 123R, based on stock options granted through December 31, 2005, we expect that the adoption of SFAS 123R on January 1, 2006, will reduce first quarter net earnings by approximately $212,000 ($0.005 per share, diluted). See Note 13 for further information on our stock-based compensation plans.

In March 2005, the FASB issued FASB Interpretation No. 47 (FIN 47) "Accounting for Conditional Asset Retirement Obligations," which clarifies the impact that uncertainty surrounding the timing or method of settling an obligation should have on accounting for that obligation under SFAS 143. As the term is used in SFAS 143, a contingent asset retirement obligation refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. For example, a company may have an obligation to retire an offshore facility, where neither the life of the facility nor the method of retirement is known. We do not currently have any assets with a contingent asset retirement obligation. Accordingly, this interpretation has not had any impact on our financial statements. FIN 47 is effective no later than the end of the fiscal year ending after December 15, 2005, or December 31, 2005 for calendar year companies.

In May 2005, the FASB issued Statement of Financial Accounting Standards No. 154 (SFAS 154) "Accounting Changes and Error Corrections — a replacement of APB Opinion No. 20 and FASB Statement No. 3." SFAS 154 establishes retrospective application as the required method for reporting a change in accounting principle, unless it is impracticable in which the changes should be applied to the latest practicable date presented for voluntary accounting changes and in the absence of specific guidance provided for in a new pronouncement issued by an authoritative body. SFAS 154 also requires that a correction of an error be reported as a prior period adjustment by restating prior period financial statements. SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005.

In February 2006, the FASB issued Statement of Financial Accounting Standards No. 155 (SFAS 155) "Accounting for Certain Hybrid Instruments — an amendment of FASB Statements No. 133 and 140." SFAS 155 amends SFAS 133 to permit fair value measurement for certain hybrid financial instruments that contain an embedded derivative, provides additional guidance on the applicability of SFAS 133 and SFAS 140 to certain financial instruments and subordinated concentrations of credit risk. SFAS 155 is effective for the first fiscal year that begins after September 15, 2006 (January 1, 2007 for us). We are currently evaluating the impact SFAS 155 will have on our consolidated financial statements.

Source of Our Revenues

We derive our revenues from the sale of oil and natural gas that is produced from our oil and natural gas properties. Revenues are a function of the volume produced and the prevailing market prices at the time of sale.

To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we utilize derivative instruments to hedge future sales prices on a portion of our oil and natural gas production. Our current strategy is to have between 25% and 40% of our current monthly-annualized production volumes hedged over the next twelve months. For example, if our production volumes for any given month was 1 Bcfe, then our annualized production would be 12 Bcfe and using our strategy, we could have between 3 Bcfe and 4.8 Bcfe of our production over the next twelve months hedged. The use of certain types of derivative instruments may prevent us from realizing the benefit of upward price movements. "See Item 1A. Risk Factors — Our hedging activities may prevent us from benefiting from price increases and may expose us to other risks."

Components of Our Cost Structure

- *Production Costs* are the day-to-day costs we incur to bring hydrocarbons out of the ground and to the market combined with the daily costs we incur to maintain our producing properties. This includes lease operating expenses and production taxes.
  - — Lease operating expenses are generally comprised of several components including the cost of labor and supervision to operate our wells and related equipment; repairs and maintenance; related materials, supplies, fuel, and supplies utilized in operating our wells and related equipment and facilities; insurance applicable to our wells and related facilities and equipment. Lease operating expenses also include the cost for expensed workovers. Lease operating expenses are driven in part by the type of commodity produced, the level of workover activity and the geographical location of the properties. Oil is inherently more expensive to produce than natural gas.
  - — Lease operating expenses also include ad valorem taxes, which are imposed by local taxing authorities such as school districts, cities, and counties or boroughs. The amount of tax we pay is based on a percent of value of the property assessed or determined by the taxing authority on an annual basis. When oil and natural gas prices rise, the value of our underlying property interests increase, and result in higher valorem taxes.
  - — In the U.S. there are a variety of state and federal taxes levied on the production of oil and natural gas. These are commonly grouped together and referred to as production taxes. The majority of our production tax expense is based on a percent of gross value realized at the wellhead at the time the production is sold or removed from the lease. As a result, our production tax expense increases when oil and gas prices rise.
  - — Historically, taxing authorities have occasionally encouraged the oil and natural gas industry to explore for new oil and natural gas reserves, or to develop high cost reserves, through reduced tax rates or tax credits. These incentives have been narrow in scope and short-lived. A small number of our wells currently qualify for reduced production taxes because they were discoveries based on the use of 3-D seismic or they are high cost wells.
- *Depreciation, Depletion and Amortization* is the systematic expensing of the capital costs incurred to acquire, explore and develop oil and natural gas. As a full cost company, we capitalize all direct costs associated with our exploration and development efforts, including a portion of our interest and certain general and administrative costs, and apportion these costs to each unit of production sold through depletion expense. Generally, if reserve quantities are revised up or down, our depletion rate per unit of production will change inversely. When the depreciable base increases or decreases, the depletion rate will move in the same direction.

- *Asset Retirement Accretion Expense* is the systematic, monthly accretion of future abandonment costs of tangible assets such as wells, service assets, pipelines, and other facilities.

- *General and Administrative* is our overhead, and includes payroll and benefits for our corporate staff, costs of maintaining our headquarters, managing our production and development operations and legal compliance. We capitalize general and administrative costs directly related to our exploration and development activities.

- *Interest.* We rely on our senior credit agreement to fund our short-term liquidity (working capital) and a portion of our long-term financing needs. As a result, we incur interest expense that correlates to both fluctuations in interest rates and to the extent that our cash flows from operations do not exceed our spending. We expect to continue to incur interest expense as we continue to grow. We capitalize interest directly related to our unevaluated properties and certain properties under development, which are not being amortized.

- *Income Taxes.* We are generally subject to a 35% federal income tax rate. For income tax purposes, we are allowed deductions for accelerated depreciation, depletion and intangible drilling costs that reduce our current tax liability. Through 2005, all of our income taxes were deferred.

Capital Commitments

Our primary needs for cash are to fund our capital expenditure program, our working capital obligations and for the repayment of contractual obligations. In the future, cash will be required to fund our capital expenditures for the exploration and development properties necessary to offset the inherent declines in production and proven reserves that are typical in an extractive industry like ours. Future success in growing reserves and production will be highly dependent on our access to cost effective capital resources and our success in economically finding and producing additional oil and natural gas reserves. Funding for our exploration and development of oil and natural gas activities and the repayment of our contractual obligations may be provided by any combination of cash flow from operations, cash on our balance sheet, the unused committed borrowing capacity under both our senior and subordinated credit agreements, reimbursements of prior land and seismic costs by third parties who participate in our projects, and the sale of interests in projects and properties or alternative financing sources as discussed in "— Contractual Obligations" and "— Capital Resources." Cash flows from operations and the unused committed borrowing capacity under our senior credit agreement fund our working capital obligations. We believe that cash on hand, net cash provided by operating activities, and the unused committed borrowing capacity under both our senior and subordinated credit agreements will be adequate to satisfy our future financial obligations and liquidity.

In the current environment of higher commodity prices, there may be increased demand for drilling equipment and services, leases and economically attractive prospects, which then may result in less availability and higher costs to us for those resources.

Capital Expenditures

The timing of most of our capital expenditures is discretionary because we have no material long-term capital expenditure commitments. Consequently, we have a significant degree of flexibility to adjust the level of our capital expenditures as circumstances warrant. Our capital expenditure program includes the following:

- cost of acquiring and maintaining our lease acreage position and our seismic resources;

- cost of drilling and completing new oil and natural gas wells;

- cost of installing new production infrastructure;

- cost of maintaining, repairing and enhancing existing oil and natural gas wells;

- cost related to plugging and abandoning unproductive or uneconomic wells; and,
- indirect costs related to our exploration activities, including payroll and other expenses attributable our exploration professional staff.

Our budgeted capital expenditures for 2006 are as follows.

	2006
	(In million)
Drilling	$120.4
Net land and seismic	28.6
Capitalized interest and G&A	7.3
Other assets	0.6
Total	$156.9

The capital that funds our drilling activities is allocated to individual prospects based on the value potential of a prospect, as measured by a risked net present value analysis. We start each year with a budget and re-evaluate this budget monthly. The primary factors that impact this value creation measure include forecasted commodity prices, drilling and completion costs, and a prospect's risked reserve size and risked initial producing rate. Other factors that are also monitored throughout the year that influence the amount and timing of all our planned expenditures include the level of production from our existing oil and natural gas properties, the availability of drilling and completion services, and the success and resulting production of our newly drilled wells. The outcome of our monthly analysis results in a reprioritization of our exploration and development drilling schedule to ensure that we are optimizing our capital expenditure plan.

Over the past three years, we have spent approximately $194.2 million to drill 52 exploratory wells and 81 developments wells. Two of these development wells were in progress at December 31, 2005.

For 2006, we currently plan to spend approximately $47 million, or 30% of our total planned capital expenditures to drill 21 exploratory wells with an average working interest of 61% and to drill and complete wells that were in progress at December 31, 2005. We believe that we possess a multi-year inventory of exploratory drilling prospects, the majority of which have been internally generated by our staff. As a consequence and considering the results that we have achieved in recent years, we expect that we will continue to emphasize our prospect generation and drilling strategy as our primary means of creating value for our stockholders.

Due to our exploratory drilling success, over the last five years, a growing percentage of our capital expenditures have been allocated to the development of past field discoveries. For 2006, we currently plan to spend approximately $73.4 million, or 47% of our total planned capital expenditures on development drilling activities, which will include the drilling of 22 development wells with an average working interest of 56% and completing wells that were in progress at December 31, 2005. We currently plan to allocate approximately $56.4 million of this capital to develop our proved undeveloped reserves at December 31, 2005.

To support our prospect generation activities, we allocate a portion of our capital expenditures to land and seismic. Over the past three years we have spent $38.5 million on land and seismic activities. For 2006, we expect to spend approximately $28.6 million or 18% of our planned capital expenditures on land and seismic activities.

Additionally, we currently plan to capitalize approximately $7.3 million of our forecasted general and administrative cost and forecasted interest in 2006.

The final determination with respect to our 2006 budgeted expenditures will depend on a number of factors, including:

- commodity prices;
- production from our existing producing wells;
- the results of our current exploration and development drilling efforts;
- economic and industry conditions at the time of drilling, including the availability of drilling and completion equipment; and
- the availability of more economically attractive prospects.

There can be no assurance that the budgeted wells will, if drilled, encounter commercial quantities of oil or natural gas.

For a more in depth discussion of our 2006 capital expenditure plan see "Item 2. Properties."

Contractual Obligations

The following schedule summarizes our known contractual cash obligations at December 31, 2005 and the effect these obligations are expected to have on our future cash flow and liquidity.

	Payments Due by Year				
	Total	2006	2007	2008-2009	2010 and Thereafter
	(In thousands)				
Debt:					
Senior credit agreement	$33,100	$ —	$ —	$ —	$33,100
Subordinated credit agreement	30,000	—	—	—	30,000
Mandatorily redeemable, Series A preferred stock	10,101	—	—	—	10,101
Total	$73,201	$ —	$ —	$ —	$73,201
Other commitments:					
Interest, senior credit agreement(a)	$ 8,401	$1,868	$1,868	$ 3,736	$ 929
Interest, subordinated credit agreement(b)	10,640	2,366	2,366	4,732	1,176
Dividend Mandatorily redeemable, Series A preferred stock(c)	2,928	606	606	1,212	504
Non-cancelable operating leases(d)	4,634	709	698	1,390	1,837
Total	$26,603	$5,549	$5,538	$11,070	$ 4,446

(a) Calculated assuming $33.1 million outstanding under our senior credit agreement, an interest rate of 5.64% and the agreement matures in June 2010. This interest rate assumes that we utilize approximately 37% of the available borrowing base during the period and a Eurodollar rate of 4.39% plus a margin of 1.25%. The Eurodollar rate used for the calculation is the one month Eurodollar rate on December 30, 2005. The amount of interest that we pay on amounts borrowed under our senior credit agreement will fluctuate over time as borrowings increase or decrease, as the applicable Eurodollar rate increases and decreases and as the applicable interest rate increases or decreases. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk — Interest Rate Risk."

(b) Calculated assuming $30 million of notes outstanding under our subordinated credit agreement, an interest rate of 7.89% and the agreement matures in June 2010. The interest rate on $20 million of our subordinated notes is fixed at 7.61% using an interest rate swap. The interest on the remaining $10 million of subordinated notes outstanding was calculated assuming a Eurodollar rate of 4.54% and a margin of 3.9% for a total interest rate of 8.44%. The Eurodollar rate used for the calculation is the three month Eurodollar rate on December 30, 2005. The amount of interest that we pay on amounts borrowed under our subordinated credit agreement will fluctuate over time as borrowings under our subordinated credit agreement increase and the applicable Eurodollar rate increases or decreases. In addition, the margin that we pay on amounts borrowed under our subordinated credit agreement will increase if the amounts we borrow under our senior credit agreement equals or exceeds 75% of the available borrowing base. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk — Interest Rate Risk."

(c) Calculated assuming $10.1 million of Series A preferred stock outstanding, a cash dividend of 6% per annum and a maturity of October 31, 2010.

(d) Not reduced by rental payments that we will receive from a non-cancelable sublease of approximately $44,000 due in 2006.

We also have liabilities of $4.4 million related to asset retirement obligations on our Consolidated Balance Sheet as of December 31, 2005. Due to the nature of these obligations, we cannot determine precisely when payments will be made to settle these obligations. See "Item 8. Financial Statements and Supplementary Data — Note 6."

Senior Credit Agreement

As of December 31, 2005, we had $33.1 million in borrowings outstanding under our senior credit agreement. In June 2005, we amended and restated our $100 million senior credit agreement to provide for revolving credit borrowings up to $200 million and to extend the maturity of the agreement from March 2009 to June 2010. Borrowings under our senior credit agreement are limited by a borrowing base which at December 31, 2005 was $90 million.

The borrowing base for our senior credit agreement is subject to redetermination at least semi-annually using the administrative agent and lenders' usual and customary criteria for oil and natural gas reserve valuation. While we do not expect the amount that we have borrowed under our senior credit agreement to exceed the borrowing base, in the event the borrowing base is adjusted below the amount that we have borrowed, we will have a borrowing base deficiency and will be required to remedy this deficiency. To remedy a borrowing base deficiency we have the option to repay borrowings equal to the deficiency within 10 days of notification, add additional assets to the borrowing base so that the deficiency is cured within 20 days or pay the borrowing base deficiency in six equal monthly installments.

Borrowings under our senior credit agreement bear interest, at our election, at a base rate or a Eurodollar rate, plus in each case an applicable margin. These margins are reset quarterly and are subject to increase if the total amount borrowed under our senior credit agreement reaches certain percentages of the available borrowing base, as shown below:

Percent of Borrowing Base Utilized	Eurodollar Rate Advances	Base Rate Advances(1)
$< 50\%$	1.250%	0.000%
$\geq 50\%$ and $< 75\%$	1.500%	0.000%
$\geq 75\%$ and $< 90\%$	1.750%	0.250%
$\geq 90\%$	2.000%	0.500%

(1) Base rate is defined as for any day a fluctuating rate per annum equal to the higher of: (a) the Federal Funds Rate plus ½ of 1% or (b) the rate of interest in effect for such day as publicly announced from time to time by Bank of America as its "prime rate." The "prime rate" is a rate set by Bank of America based upon various factors including Bank of America's costs and desired return, general economic conditions and other factors, and is used as a reference point for pricing some loans, which may be priced at, above, or below such announced rate. Any change in such rate announced by Bank of America shall take effect at the opening of business on the day specified in the public announcement of such change.

We are also required to pay a quarterly commitment fee on the average daily unused portion of the borrowing base. The commitment fees we pay are reset quarterly and are subject to change as the percentage of the available borrowing base that we utilize changes. The margins and commitment fees that we pay are as follows:

Percent of Borrowing Base Utilized	Quarterly Commitment Fee
< 50%	0.250%
≥ 50% and < 75%	0.250%
≥ 75% and < 90%	0.375%
≥ 90%	0.375%

Pursuant to our senior credit agreement, we are required to maintain a current ratio of at least 1 to 1 and an interest coverage ratio for the four most recent quarters of at least 3 to 1. Our current ratio at December 31, 2005 and interest coverage ratio for the twelve-month period ended December 31, 2005, were 2.7 to 1 and 20.4 to 1, respectively. As of December 31, 2005, and for the twelve-month period then ended, we were in compliance with all covenant requirements in connection with our senior credit agreement.

We strive to manage the amounts borrowed under our senior credit agreement in order to maintain excess borrowing capacity. As of February 27, 2006, we had $44.3 million of borrowings outstanding and $45.7 million of additional borrowing capacity under our senior credit agreement.

See "— Analysis of Changes in Cash & Cash Equivalents — Analysis of changes in cash flows from financing activities — Senior Credit Agreement" for explanation of prior year changes in our outstanding debt balance under our senior credit agreement.

Senior Subordinated Notes

In June 2005, we amended our $20 million subordinated credit agreement, to provide up to $40 million in borrowings and to extend the maturity of the agreement from March 2009, to June 2010. Borrowings under our subordinated credit agreement are secured obligations ranking junior to borrowings under our senior credit agreement. Upon closing, we borrowed an additional $10 million of notes under our subordinated credit agreement, which increased the amounts we had borrowed under our subordinated credit agreement to $30 million. As of December 31, 2005, we had $30 million of notes outstanding under our subordinated credit agreement. We will have the opportunity to draw the additional $10 million of notes available to us under our subordinated credit agreement until December 2006.

Borrowings under our subordinated credit agreement bear interest based on the Eurodollar rate plus a margin. This margin is subject to increase if we borrow the remaining notes available to us under our subordinated credit agreement or the total amount borrowed under our senior credit agreement reaches or exceeds 75% of the available borrowing base, as shown below.

Percent of Senior Credit Agreement Borrowing Base Utilized	Debt Outstanding under Subordinated Credit Agreement		
	< $30 Million	> $30 Million and < $35 Million	> $35 Million
< 75%	3.90%	3.90%	3.90%
≥ 75% and < 90%	3.90%	4.25%	4.50%
≥ 90%	3.90%	4.25%	4.50%

We are required to a pay a quarterly commitment fee of 0.750% on the unused portion of our subordinated credit agreement.

In December 2005, we amended the price deck used to calculate NPV for the Total Calculated NPV to Total Debt Ratio. The amended price assumptions used to determine NPV for reserves will be based upon the following price decks: (i) for natural gas, the gas strip price, provided that if any gas strip price is greater than $5.50 per MMBtu, the price shall be capped at $5.50 per MMBtu; and (ii) for oil, the oil strip price, provided that if any oil strip price is greater than $36 per barrel, the price shall be capped at $36 per barrel.

Pursuant to our subordinated credit agreement, we are required to maintain a current ratio of at least 1 to 1, and an interest coverage ratio for the four most recent quarters of at least 3 to 1. Our current ratio at December 31, 2005 and interest coverage ratio for the twelve-month period ended December 31, 2005 were 2.7 to 1 and 20.4 to 1, respectively. At December 31, 2005 and for the twelve-month period then ended, we were in compliance with all covenant requirements in connection with our subordinated credit agreement.

See "— Analysis of Changes in Cash & Cash Equivalents — Analysis of changes in cash flows from financing activities — Senior Subordinated Notes" for explanation of prior year changes in borrowings outstanding under our subordinated credit agreement.

Mandatorily Redeemable Preferred Stock

As of December 31, 2005, we had $10.1 million of mandatorily redeemable Series A preferred stock outstanding, which is held by funds managed by affiliates of Credit Suisse First Boston (USA), Inc. From issuance through September 2005, we paid the dividends on our Series A preferred stock in kind. Our option to pay the dividends on our Series A preferred stock in kind expired in October 2005 and we are now required to satisfy all dividend obligations related to our Series A preferred stock in cash at a rate of 6% per annum until it matures in October 2010 or until it is redeemed. During the fourth quarter of 2005, we paid cash dividends of $153,000. Our Series A preferred stock is redeemable at our option at 100% or 101% of the stated value per share (depending upon certain conditions) at anytime prior to maturity.

Our preferred stock balance outstanding at December 31, 2005, represents the balance of preferred stock outstanding subsequent to the exercise by CSFB Private Equity of its warrants to purchase our common stock in November and December 2003 and the shares of preferred stock that we have issued to satisfy dividend obligations on this preferred stock. For the year ended December 31, 2005, we issued 29,065 shares of additional Series A preferred stock to satisfy our dividend obligations.

See "— Analysis of Changes in Cash & Cash Equivalents — Analysis of changes in cash flows from financing activities — Mandatorily Redeemable Preferred Stock" and "Item 5. Market for Registrant's Common Equity and Related Stockholder Matters and Issuer Purchases of Equity Securities — Recent Issuances of Unregistered Securities — Mandatorily Redeemable Preferred Stock."

Off Balance Sheet Arrangements

We currently have operating leases, which are considered off balance sheet arrangements. We do not currently have any other off balance sheet arrangements or other such unrecorded obligations, and we have not guaranteed the debt of any other party.

Capital Resources

In 2006, we intend to fund our capital expenditure program and contractual commitments with cash flows from operations, borrowings under both our senior and subordinated credit agreements and if required, alternative financing sources. Our primary sources of cash during 2005 were funds generated by operations, borrowings under both our senior and subordinated credit agreements and the net proceeds received from the sale of common stock. Cash from the common stock sale was used to reduce borrowings outstanding under our senior credit agreement which will be reborrowed to fund exploration and development activities. We made aggregate cash payments of $4 million for interest in 2005.

Net cash provided by operating activities

Net cash provided by operating activities is a function of the prices that we receive from the sale of our oil and natural gas, which are inherently volatile and unpredictable, gains or losses related to hedging, production, operating cost and our cost of capital. Our asset base, as with other extractive industries, is a depleting one in which each Mcf of natural gas or barrel of oil produced must be replaced or our ability to generate cash flow, and thus fund and sustain our exploration and development activities, will diminish. During 2005, 2004 and 2003, net cash provided by operating activities was 57%, 67% and 90% of our net cash used by investing activities, respectively. See "Item 1A. Risk Factors — Our exploration, development and drilling efforts and the operation of our wells may not be profitable or achieve our targeted returns" and "Item 1A. Risk Factors — We may have difficulty financing our planned capital expenditures, which could adversely affect our business."

Senior Credit Agreement

In June 2005, we amended and restated our $100 million senior credit agreement to provide for revolving credit borrowings up to $200 million and to extend the maturity of the agreement from March 2009 to July 2010. The amount that we can borrow under our senior credit agreement is limited by a borrowing base. Upon amendment, the committed borrowing base for our senior credit agreement was $80 million and was increased to $90 million in November 2005. Our senior credit agreement also permits letters of credit up to the lesser of $10 million or the unused committed borrowing base. Issuances of letters of credit reduce the amount of borrowings available to us under our senior credit agreement.

As of December 31, 2005, we had $56.9 million of unused committed borrowing capacity available to us under our senior credit agreement. Since the borrowing base for our senior credit agreement is redetermined at least semi-annually, the amount of borrowing capacity available to us under our senior credit agreement could fluctuate. While we do not expect the amount that we have borrowed under our senior credit agreement to exceed the borrowing base, in the event that the borrowing base is adjusted below the amount that we have borrowed, our access to further borrowings will be reduced, and we may not have the resources necessary to carry out our planned spending for exploration and development activities. As of February 27, 2006, we had $45.7 million of unused committed borrowing capacity available to us under our senior credit agreement. See "— Capital Commitments — Senior Credit Agreement."

Our senior credit agreement also contains customary restrictions and covenants. Should we be unable to comply with these or other covenants, our senior lenders may be unwilling to waive compliance or amend the covenants and our liquidity may be adversely affected. See "Item 1A. Risk Factors — Our level of indebtedness may adversely affect our cash available for operations, which would limiting our growth, our ability to make interest and principal payments on our indebtedness as they become due and our flexibility to respond to market changes" and "— Capital Commitments — Senior Credit Agreement."

Senior Subordinated Notes

As of December 31, 2005, we had $10 million of borrowing capacity available to us under our subordinated credit agreement. These notes are available to us for borrowing until December 2006. In June 2005, we amended our $20 million subordinated credit agreement to provide up to $40 million of borrowings and to extend the maturity of the agreement from March 2009 until June 2010. As of December 31, 2005, we had $30 million of senior subordinated notes outstanding.

The future amounts of debt that we borrow under our senior and subordinated credit agreements will depend primarily on net cash provided by operating activities, proceeds from other financing activities, reimbursements of prior land and seismic costs by third party participants in our projects and proceeds generated from asset dispositions.

We strive to manage the amounts we borrow under our senior and subordinated credit agreements in order to maintain excess borrowing capacity.

Access to Capital Markets

We currently have an effective universal shelf registration statement covering the sale, from time to time, of our common stock, preferred stock, depositary shares, warrants and debt securities, or a combination of any of these securities. With the completion of the November 2005 equity offering, the existing shelf registration statement had $73.4 million available. In July 2004, we sold 2,598,500 shares of our common stock and in November and December 2005, we sold 8,625,000 total shares of our common stock under this registration statement. However, our ability to raise additional capital using our shelf registration statement may be limited due to overall conditions of the stock market or the oil and natural gas industry.

In February 2006, we filed a new universal shelf registration statement registration statement allowing us to issue common stock, preferred stock, depositary shares, warrants, senior debt and subordinated debt up to an aggregate amount of $300 million. Our new universal shelf registration statement has yet to be declared effective by the SEC.

Commodity Prices

Changes in commodity prices significantly affect our capital resources, liquidity and operating results. Price changes directly affect revenues and can indirectly impact expected production by changing the amount of capital available we have to reinvest in our exploration and development activities. Commodity prices are impacted by many factors that are outside of our control. Over the past couple of years, commodity prices have been very volatile. We expect that commodity prices will continue to fluctuate significantly in the future. As a result, we cannot accurately predict future oil and natural gas prices, and therefore, we cannot determine what effect increases or decreases will have on our capital program, production volumes and future revenues.

The prices we receive for our oil production are based on global market conditions. Our average pre-hedged sales price for oil in 2005 was $54.73 per barrel, which was 36% higher and 78% higher than the prices we received in 2004 and 2003, respectively. Significant factors that will impact 2006 oil prices include developments in Iraq and other Middle East countries and the extent to which members of the Organization of Petroleum Exporting Countries and other oil exporting nations are able to manage oil supply through export quotas.

North American market forces primarily drive the prices we receive for our natural gas production. Factors that can affect the price of natural gas are changes in market demands, overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. Over the past three years natural gas prices have been volatile. Our average sales price for natural gas in 2005 was $8.29 per Mcf, which was 37% higher and 46% higher than the prices that we received in 2004 and 2003, respectively. The increase North American gas prices in 2005 were in response to strong supply and demand fundamentals. Natural gas prices for 2006 will depend on variations in key North American gas supply and demand indicators.

Results of Operations

Comparison of the twelve-month periods ended December 31, 2005, 2004 and 2003

Production volumes

	Year Ended December 31,				
	2005	% Change	2004	% Change	2003
Oil (MBbls)	450	(21)%	573	(20)%	720
Natural gas (MMcf)	9,213	4%	8,830	39%	6,356
Total (MMcfe)(1)	11,913	(3)%	12,265	15%	10,674
Average daily production (MMcfe/d)	33.1		34.1		29.7

(1) Mcfe is defined one million cubic feet equivalent of natural gas, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Our net equivalent production volumes for 2005 were 11.9 Bcfe (33.1 MMcfe/d) compared to 12.3 Bcfe (34.1 MMcfe/d) in 2004. When compared to 2004, our production volumes for 2005 declined because new production from wells that we drilled and completed during the last quarter of 2004 and during 2005 did not offset the natural decline of production from wells that we drilled and completed in prior periods. However, our production volumes for the fourth quarter of 2005 were 40.8 MMcfe/d or 23% higher than our average daily production volumes for 2005. Natural gas represented 77% and 72% of our total production in 2005 and 2004, respectively.

The following is additional information regarding our 2005 production.

- Production from our onshore Gulf Coast province for 2005 decreased 10% when compared to 2004. Production from this province represented 57% of our total production in 2005 versus 61% in 2004. Approximately 78% of our 2005 production from this province was natural gas compared to 74% in 2004.

- Production from our Anadarko Basin province for 2005 increased 17% when compared to 2004. Production from this province represented 34% of our total production in 2005 versus 29% in 2004. Approximately 92% of our 2005 production from this province was natural gas compared to 88% in 2004.

- Production from our West Texas province for 2005 decreased 18% when compared to 2004. Production from this province represented 9% of our total production in 2005 versus 10% in 2004. Production from this province is primarily oil and approximately 85% of our production from this province in 2005 was oil versus 86% in 2004.

Our net equivalent production volumes for 2004 were 12.3 Bcfe (34.1 MMcfe/d) compared to 10.7 Bcfe (29.7 MMcfe/d) in 2003. The increase in our production volumes was due to production growth from wells that we drilled and completed during the last quarter of 2003 and during 2004. New production from these wells was partially offset by the natural decline of existing production. Natural gas represented 72% and 60% of our total production in 2004 and 2003, respectively.

The following is additional information regarding our 2004 production.

- Production from our onshore Gulf Coast province for 2004 increased 14% when compared to 2003. Production from this province represented 61% of our total production in 2004 versus 62% in 2003. Approximately 74% of our 2004 production from this province was natural gas compared to 60% in 2003.

- Production from our Anadarko Basin province for 2004 increased 46% when compared to 2003. Production from this province represented 29% of our total production in 2004 versus 22% in 2003. Approximately 88% of our 2004 production from this province was natural gas compared to 90% in 2003.

- Production from our West Texas province for 2004 decreased 26% when compared to 2003. West Texas production represented 10% of our total production versus 16% in 2003. Production from our West Texas province is primarily oil and in both 2004 and 2003 approximately 90% of our production from this province was oil.

Hedging, commodity prices and revenues

The following table shows the type of derivative contracts, the volumes, the weighted average NYMEX reference price for those volumes, and the associated gain / (loss) upon settlement of those contracts for 2005, 2004 and 2003.

	Year Ended December 31,				
	2005	% Change	2004	% Change	2003
Oil swaps					
Volumes (MBbls)	—	NM	73	(67)%	226
Average swap price (per Bbl)	$ —	NM	$ 24.65	1%	$ 24.51
Gain / (loss) upon settlement (in thousands)	$ —	NM	$(1,073)	(28)%	$(1,488)
Oil collars					
Volumes (MBbls)	118	(34)%	179	298%	45
Average floor price (per Bbl)	$ 37.40	50%	$ 24.92	38%	$ 18.00
Average ceiling price (per Bbl)	$ 47.20	51%	$ 31.21	38%	$ 22.56
Gain / (loss) upon settlement (in thousands)	$(1,249)	(29)%	$(1,768)	345%	$ (397)
Total oil					
Volumes (MBbls)	118	(53)%	252	(8)%	271
Gain / (loss) upon settlement (in thousands)	$(1,249)	(56)%	$(2,841)	51%	$(1,885)
Natural gas swaps					
Volumes (MMbtu)	—	NM	753	(72)%	2,664
Average swap price (per MMbtu)	$ —	NM	$ 4.53	19%	$ 3.81
Gain / (loss) upon settlement (in thousands)	$ —	NM	$(1,066)	(78)%	$(4,807)
Natural gas collars					
Volumes (MMbtu)	2,643	6%	2,504	NM	—
Average floor price (per MMbtu)	$ 5.93	31%	$ 4.54	NM	$ —
Average ceiling price (per MMbtu)	$ 7.86	15%	$ 6.85	NM	$ —
Gain / (loss) upon settlement (in thousands)	$(2,925)	272%	$ (787)	NM	$ —
Natural gas floors					
Volumes (MMbtu)	—	NM	—	NM	1,070
Average floor price (per MMbtu)	$ —	NM	$ —	NM	$ 4.50
Gain / (loss) upon settlement (in thousands)	$ —	NM	$ —	NM	$ —
Total natural gas					
Volumes (MMbtu)	2,643	(19)%	3,257	(13)%	3,734
Gain / (loss) upon settlement (in thousands)	$(2,925)	58%	$(1,853)	(61)%	$(4,807)

Reported revenues from the sale of oil and natural gas are based on the market price we receive adjusted for marketing charges and the results from the settlement of our derivative contracts that qualify for cash flow hedge accounting treatment under SFAS 133.

We utilize swap, collar, three way costless collar and floor contracts to (i) reduce the effect of price volatility on the commodities that we produce and sell, (ii) reduce commodity price risk and (iii) provide a base level of cash flow in order to assure we can execute at least a portion of our capital spending plans. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk — Derivative Instruments and Hedging Activities" for a description of our derivative contracts and our open derivative contracts.

The effective portions of changes in the fair values of our derivative contracts that qualify for cash flow hedge accounting treatment under SFAS 133 are reported as increases or decreases to stockholders' equity until the underlying contract is settled. Consequentially, changes in the effective portions of these contracts add volatility to our reported stockholders' equity until the contract is settled or is terminated. See "Item 8. Financial Statements and Supplementary Data — Note 10."

Gains or losses related to the settlement and the changes in the fair values of our derivative contracts that do not qualify for cash flow hedge accounting treatment under SFAS 133 are reported in other income (expense).

See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk — Derivative Instruments and Hedging Activities" for our open derivative contracts.

Commodity prices and revenues

The following table shows our revenue from the sale of oil and natural gas for 2005, 2004 and 2003.

	Year Ended December 31,				
	2005	% Change	2004	% Change	2003
	(In thousands, except per unit measurements)				
Revenue from the sale of oil and natural gas:					
Oil sales	$ 24,628	7%	$22,976	4%	$22,157
Gain (loss) due to hedging	(1,249)	(56)%	(2,841)	51%	(1,885)
Total revenue from the sale of oil	$ 23,379	16%	$20,135	(1)%	$20,272
Natural gas sales	$ 76,366	43%	$53,431	48%	$36,080
Gain (loss) due to hedging	(2,925)	58%	(1,853)	(61)%	(4,807)
Total revenue from the sale of natural gas	$ 73,441	42%	$51,578	65%	$31,273
Oil and natural gas sales	$100,994	32%	$76,407	31%	$58,237
Gain (loss) due to hedging	(4,174)	(11)%	(4,694)	(30)%	(6,692)
Total revenue from the sale of oil and natural gas	$ 96,820	35%	$71,713	39%	$51,545
Average prices:					
Oil sales price (per Bbl)	$ 54.73	36%	$ 40.13	30%	$ 30.79
Gain (loss) due to hedging (per Bbl)	(2.78)	(44)%	(4.96)	89%	(2.62)
Realized oil price (per Bbl)	$ 51.95	48%	$ 35.17	25%	$ 28.17
Natural gas sales price (per Mcf)	$ 8.29	37%	$ 6.05	7%	$ 5.68
Gain (loss) due to hedging (per Mcf)	(0.32)	52%	(0.21)	(72)%	(0.76)
Realized natural gas price (per Mcf)	$ 7.97	36%	$ 5.84	19%	$ 4.92
Natural gas equivalent sales price (per Mcfe)	$ 8.48	36%	$ 6.23	14%	$ 5.46
Gain (loss) due to hedging (per Mcfe)	(0.35)	(8)%	(0.38)	(40)%	(0.63)
Realized natural gas equivalent (per Mcfe)	$ 8.13	39%	$ 5.85	21%	$ 4.83

	2004 to 2005	2003 to 2004
Change in revenue from the sale of oil		
Price variance impact	$ 6,570	$ 5,348
Volume variance impact	(4,918)	(4,529)
Cash settlement of hedging contracts	1,592	(956)
Total change	$ 3,244	$ (137)
Change in revenue from the sale of natural gas		
Price variance impact	$20,627	$ 3,275
Volume variance impact	2,308	14,076
Cash settlement of hedging contracts	(1,072)	2,954
Total change	$21,863	$20,305

Our revenues from the sale of oil and natural gas for 2005 increased 35% over our revenues in 2004. This compares to a 39% increase in our oil and natural gas revenues in 2004 over those in 2003.

The following were the primary reasons for the increase in our 2005 revenues over revenues in 2004.

- A $2.25 increase in the sales price we received for oil and natural gas combined with a decrease in losses related to the settlement of derivative contracts increased our revenues by $27.2 million and $520,000 respectively.
- These increases were partially offset by a $2.6 million decrease to revenues due to lower production.

The following were the primary reasons for the increase in our 2004 revenues over revenues in 2003.

- Approximately $9.6 million of the increase in revenues was due to a 15% increase in our production volumes.
- Approximately $8.6 million of the increase in revenues was due to an increase in the sales price we received for oil and natural gas.
- Approximately $2 million of the increase in revenues was due a decrease in losses associated with the cash settlement of derivative contracts.

Other revenue. Other revenue relates to fees that we charge other parties who use our gas gathering systems that we own to move their production from the wellhead to third party gas pipeline systems. Other revenue for 2005 was $220,000 compared to $515,000 in 2004 and $132,000 in 2003. Costs related to our gas gathering systems are recorded in lease operating expenses.

Operating costs and expenses

Production costs. Production costs include lease operating expenses and production taxes.

	Year Ended December 31,				
	2005	% Change	2004	% Change	2003
	(In thousands, except per unit measurements)				
Production costs:					
Operating & maintenance	$ 5,568	24%	$4,480	31%	$3,420
Expensed workovers	492	(44)%	878	(22)%	1,123
Ad valorem taxes	1,101	35%	815	24%	657
Lease operating expenses	$ 7,161	16%	$6,173	19%	$5,200
Production taxes	3,353	8%	3,107	25%	2,477
Production costs	$10,514	13%	$9,280	21%	$7,677

	Year Ended December 31,				
	2005	% Change	2004	% Change	2003
	(In thousands, except per unit measurements)				
Production costs (per Mcfe):					
Operating & maintenance	$ 0.47	31%	$ 0.36	13%	$ 0.32
Expensed workovers	0.04	(43)%	0.07	(36)%	0.11
Ad valorem taxes	0.09	29%	0.07	17%	0.06
Lease operating expenses	$ 0.60	20%	$ 0.50	2%	$ 0.49
Production taxes	0.28	12%	0.25	9%	0.23
Production costs	$ 0.88	17%	$ 0.75	4%	$ 0.72

One of the reasons for the overall increase in our production costs over the past three years has been due to an increase in our number of producing wells. In the future we anticipate that our production costs will increase as we add new wells and production facilities and continue to maintain production from existing maturing properties. Changes in commodity prices will also have an affect on ad valorem taxes and production taxes.

Our operating and maintenance (O&M) expenses for 2005 were up 24% when compared to 2004. This compares to a 31% increase in our O&M expenses in 2004 when compared to 2003.

The following were the primary reasons for the increase in our 2005 O&M expenses versus those in 2004.

- O&M expenses associated with new wells that began producing in 2005 were $480,000.
- O&M expenses associated with wells that were producing at the start of 2005 were up 14% when compared to 2004. Increases in costs for compressor rental and maintenance, saltwater disposal, overhead fees, contract labor, equipment rental, pumping services, water treating and miscellaneous expenses were the primary reasons for this increase. These increases were partially offset by a decrease in lease maintenance costs.

The following were the primary reasons for the increase in our 2004 O&M expenses versus those in 2003.

- O&M expenses associated with new wells that began producing in 2004 were $638,000.
- O&M expenses associated with wells that were producing at the start of 2004 were up 12% when compared to 2003. Increases in costs for compressor rental and maintenance, saltwater disposal, and electricity were the primary reasons for this increase. These increases were partially offset by a decrease in costs for contract labor, testing and treating chemicals, well service and repair and miscellaneous expenses.

Our expensed workover costs for 2005 were down 44% when compared to 2004. This compares to a 22% decline in our expensed workover costs in 2004 when compared to 2003. The primary reason for these declines was a decrease in the costs of the types of workovers operations that were performed. For both 2005 and 2004, the number of wells with expensed workover costs increased but the average expensed workover cost per well decreased.

Our ad valorem tax expense for 2005 was up 35% when compared to 2004. This compares to a 24% increase in our ad valorem tax expense in 2004 when compared to 2003. An increase in property valuations due to higher commodity prices was the primary reason for the increase in our ad valorem taxes for both 2005 and 2004.

Our production tax expense for 2005 was up 8% when compared to 2004. This compares to a 25% increase in our production tax expense in 2004 when compared to 2003.

The following were the primary reasons for the increase in our 2005 production tax expense when compared to 2004.

- A 36% increase in the pre-hedge sales price that we received for our oil and natural gas was partially offset by a reduction in our 2005 production combined with our receipt of $1.6 million of production tax credits related to 16 high cost gas wells. Our effective production tax rate for 2005 was 3.3% of our pre-hedge revenue from the sale of oil and natural gas compared to 4.1% in 2004.

The following were the primary reasons for the increase in our 2004 production tax expense when compared to 2003.

- Higher production volumes combined with a 14% increase in the pre-hedge sales price that we received for our oil and natural gas. Our effective production tax rate for 2004 was 4.1% of our pre-hedge revenue from the sale oil and natural compared to 4.3% in 2003.

We believe that per unit of production measures are the best way to evaluate our production costs. We use this information to evaluate our performance relative to our peers and to internally evaluate our performance.

For 2005, our unit production cost increased 17% when compared to 2004. This compares to a 4% increase in our 2004 unit production cost when compared to 2003.

The following were the primary reasons for the increase in our 2005 production costs over 2004.

- Approximately $0.04 per Mcfe of the increase in our O&M expenses was due to cost associated with new wells that began producing in 2005.
- Ad valorem taxes increased due to higher property valuations for our oil and natural gas properties due to higher commodity prices.
- Production taxes were $0.03 higher per Mcfe due to an increase in the sales price that we received for our oil and natural gas. The increase in our production tax on a per unit basis due to higher prices was partially offset by $0.14 decrease due to production tax credits.
- A decrease in expensed workover costs partially offset $0.03 per Mcfe of this increase.

The following were the primary reasons for the increase in our 2004 production costs over 2003.

- Approximately $0.05 per Mcfe of the increase in our O&M expenses was due to cost associated with new wells that began producing in 2004.
- Ad valorem taxes increased due to higher property valuations for our oil and natural gas properties due to higher commodity prices.
- Production taxes were $0.02 higher due to an increase in the sales price that we received for our oil and natural gas.
- A decrease in expensed workover cost partially offset $0.04 per Mcfe of this increase.

General and administrative expenses. We capitalize a portion of our general and administrative costs. The costs capitalized represent the cost of technical employees, who work directly on capital projects. An engineer designing a well is an example of a technical employee working on a capital project. The cost of a technical employee includes associated technical organization costs such as supervision, telephone and postage.

	Year Ended December 31,				
	2005	% Change	2004	% Change	2003
	(In thousands, except per unit measurements)				
General and administrative costs	$10,380	1%	$10,264	13%	$ 9,121
Capitalized general and administrative costs	(4,847)	(1)%	(4,872)	5%	(4,621)
General and administrative expenses	$ 5,533	3%	$ 5,392	20%	$ 4,500
General and administrative expense (per Mcfe)	$ 0.46	5%	$ 0.44	5%	$ 0.42

Our general and administrative expenses in 2005 were $141,000 higher than 2004. This compares to an increase of $892,000 in 2004 general and administrative expenses over 2003.

The following were the primary reasons for the increase in our 2005 general and administrative expenses over 2004.

- A $147,000 increase in total compensation expense due to a combination of an increase in the number of employees hired and higher medical benefit costs.
- A $435,000 increase in bad debt expense. In 2005, we recorded $447,000 in bad debt expense related to an unpaid account receivable. This amount is our estimate of the amount that will not be collected. Additionally, we recorded $9,000 in bad debt expense for an account receivable that has been deemed uncollectible.
- These increases were offset by $188,000 decrease in fees paid for contract and professional services, $161,000 decrease in office rent, a $31,000 decrease in costs for financial reporting. A decrease in the legal fees we paid was the primary reason for the decrease in our 2005 contract and professional service cost.

The following were the primary reasons for the increase in our 2004 general and administrative expenses over 2003.

- We paid approximately $399,000 to outside consultants and our independent public accountants for the implementation of Section 404 of Sarbanes-Oxley.
- We paid $242,000 related to the settlement of a legal dispute over the ownership of a well.
- Increases in payroll and benefits expense, fees paid to outside reserve engineers, franchise taxes and corporate insurance were the other primary reasons for the increase in general and administrative expenses.

Depletion of oil and natural gas properties. Our full-cost depletion expense is driven by many factors including certain costs spent in the exploration and development of producing reserves, production levels, and estimates of proved reserve quantities and future developmental costs at the end of the year.

	Year Ended December 31,				
	2005	% Change	2004	% Change	2003
	(In thousands, except per unit measurements)				
Depletion of oil and natural gas properties	$33,268	40%	$23,844	42%	$16,819
Depletion of oil and natural gas properties (per Mcfe)	$ 2.79	44%	$ 1.94	23%	$ 1.58

Our depletion expense for 2005 was 40% higher than 2004. This compares to a 42% increase in our 2004 depletion expense over 2003.

Approximately $10.2 million of the increase in our depletion expense for 2005 was due to an increase in the depletion rate. This increase was partially offset by a $737,000 decrease in our 2005 production volumes. Our depletion rate increased as a result of the higher cost of proved reserves additions in 2005 than has been the case in prior years.

For 2004 compared to 2003, a $0.36 per Mcfe increase in our depletion rate accounted for approximately 64% of the increase in our total depletion expense and increased production volumes accounted for approximately 26% of the increase. The increase in our depletion rate was due to downward reserve revisions due to disappointing drilling results related to two proved undeveloped wells at our Mills Ranch and Floyd Fault Block fields that were drilled in 2004, a decline in performance of our Floyd South Field and in certain West Texas water drive wells and to the higher cost of proved reserve additions in 2004 than has been the case in prior years.

Based on our estimated proved reserves at December 31, 2005, we expect our 2006 depletion rate to be $3.17 per Mcfe.

Net interest expense. The interest that we pay on outstanding borrowings under both our senior and subordinated credit agreements combined with dividends that we pay on our Series A mandatorily redeemable preferred stock represent the largest portion of our interest costs. Our interest costs also include the commitment fees that we pay on the unused portion of the borrowing base for our senior credit agreement and on the unused portion of our subordinated credit agreement. We typically pay loan and debt issuance costs when we enter into new lending agreements or amend existing agreements. When incurred, these costs are recorded as non-current assets and are then amortized over the life of the loan. We capitalize interest costs on borrowings associated with our major capital projects prior to their completion. This capitalized interest is added to the cost of the underlying assets and is amortized over the lives of the assets.

	Year Ended December 31,				
	2005	% Change	2004	% Change	2003
	(In thousands)				
Interest on senior credit facility	$ 2,267	157%	$ 882	(47)%	$ 1,674
Interest on senior subordinated notes(a)	1,948	14%	1,703	(28)%	2,369
Commitment fees	133	(44)%	236	61%	147
Dividend on mandatorily redeemable preferred stock	734	1%	726	114%	340
Amortization of deferred loan & debt issuance cost	491	(36)%	766	(27)%	1,053
Other general interest expense	11	(58)%	26	(48)%	50
Capitalized interest expense	(1,604)	34%	(1,195)	46%	(818)
Net interest expense	$ 3,980	27%	$ 3,144	(35)%	$ 4,815
Weighted average debt outstanding	$80,180	42%	$56,352	(21)%	$71,392
Average interest rate on outstanding indebtedness(b)	6.3%		6.3%		6.3%

(a) Includes the effects of the interest rate swap.

(b) Calculated as the sum of the interest on our outstanding indebtedness, commitment fees that we pay on our unused borrowing capacity and the dividend on our mandatorily redeemable preferred stock divided by the weighted average debt and preferred stock outstanding for the period.

Our net interest expense for 2005 was 27% higher than 2004. This compares to a 35% decrease in our 2004 net interest expense when compared to 2003.

The following were the primary reasons for the increase in our 2005 net interest expense when compared to 2004.

- Interest related to our senior credit agreement in 2005 was 59% higher than 2004. During 2005, we paid $1.4 million more interest on amounts borrowed under our senior credit agreement than we did in 2004. The primary reason for this was an increase in the Eurodollar rate combined with an increase in the weighted average amount we borrowed under our senior credit agreement during 2005. This increase was partially offset by a decrease in the commitment fees we paid on the unused portion of the available borrowing base and a decrease in our amortized deferred loan and debt issuance costs. Our weighted average debt outstanding under our senior credit agreement during 2005 represented approximately 59% of our available borrowing base, compared to 40% in 2004.
- Interest related to our subordinated credit agreement in 2005 was 15% higher than 2004. During 2005, we paid $245,000 more interest on the amounts we borrowed under our subordinated credit agreement than we did in 2004. The primary reason for this was an increase in the weighted average debt outstanding under our subordinated credit agreement during 2005. During 2005, we

also began paying commitment fees on the unused portion of our subordinated credit agreement. When we amended the agreement in June 2005, we increased the amount available to us for borrowing under our subordinated credit agreement from $20 million to $40 million. Upon closing of the amendment, we borrowed an additional $10 million, which left us with an additional $10 million available for borrowing. The commitment fees we paid on our subordinated notes in 2005 were related to the remaining $10 million available to us.

- Dividends that we paid on our mandatorily redeemable preferred stock in 2005 were 1% higher than 2004. During the first three quarters of 2005, we issued 29,065 shares of our mandatorily redeemable preferred stock to pay the dividend obligations related to our preferred stock. Our option to pay the dividends on our preferred stock in kind expired in October 2005. The dividends on our preferred stock for the remainder of 2005 were paid in cash at a rate of 6% per annum. We will continue to pay the 6% cash dividend on our preferred stock until the preferred stock matures on October 31, 2010 or until it is redeemed.

- The amount of interest that we capitalized during 2005 increased due to an increase in interest rates throughout the year. Approximately $406,000 of our capitalized interest in 2005 was related to one exploration well, the Mills Ranch #2-98, that was drilling at December 31, 2004 and completed in September 2005.

The following were the primary reasons for the decrease in our 2004 net interest expense when compared to 2003.

- Interest related to our senior credit agreement in 2004 was 29% lower than 2003. During 2004 we paid $792,000 less interest on amounts borrowed under our senior credit agreement than we did in 2003. During 2004, we utilized a smaller percentage of our available borrowing base during the period which resulted in a lower interest rate on amounts borrowed. Our weighted average debt outstanding under our senior credit facility during 2004 represented approximately 40% of our available borrowing base, compared to 66% in 2003. The decrease in interest due to a decrease in borrowing was partially offset by a 61% increase in the commitment fees that we paid on the unused portion of our borrowing base during 2004.

- Interest related to our subordinated credit agreement in 2004 was 34% lower than 2003. We paid $666,000 less interest on amounts borrowed under our subordinated credit agreement in 2004 than we did in 2003. One of the primary reasons for this decrease was a 10% decrease in our weighted average notes outstanding under our subordinated credit agreement during the period combined with a decrease in the interest rate that we paid on the outstanding notes. Our amortized deferred loan costs for 2004 were also $325,000 lower than 2003.

- The amount of interest that we capitalized during 2004 increased due to an increase in our unevaluated property balance throughout the year. Approximately $200,000 of our capitalized interest in 2004 was related to the Mills Ranch #2-98 exploration well that was drilling at December 31, 2004.

- A 114% increase in the dividends that we paid on our mandatorily redeemable preferred stock due to 2004 includes a full year of dividends whereas 2003 only includes dividends for half the year due to the adoption of SFAS 150 in July 2003. In 2004 we issued 36,264 shares of our mandatorily redeemable preferred stock to pay the dividend obligations related to our preferred stock.

Other income (expense). Other income (expense) primarily includes non-cash gains (losses) resulting from the change in fair market value of oil and gas derivative contracts that did not qualify as cash flow hedges under SFAS 133, cash gains (losses) on the settlement of these contracts and non-cash gains (losses) related to charges for the ineffective portions of our derivative contracts that qualified as cash flow hedges under SFAS 133.

Other income (expense) included:

	Year Ended December 31,				
	2005	% Change	2004	% Change	2003
	(In thousands)				
Non-cash gain (loss) due to change in fair market value of derivative contracts that did not qualify as cashflow hedge under SFAS 133	$ (92)	178%	$(33)	NM	$ —
Non-cash gain (loss) for ineffective portion of cash flow hedges	(722)	NM	658	NM	(455)
Gain (loss) on disposal of assets	(134)	NM	117	NM	—
Other	372	NM	—	(100)%	(146)
Other income (loss)	$(576)	NM	$742	223%	$(601)

The following table shows the volumes and the weighted average NYMEX reference price for our derivative contracts that we did not designate as cash flow hedges under SFAS 133 in 2005, 2004 and 2003.

	Year Ended December 31,				
	2005	% Change	2004	% Change	2003
Written natural gas puts					
Volumes (MMbtu)	1,250,000	793%	140,000	NM	—
Average ceiling price ($ per MMbtu)	$ 5.88	7%	$ 5.50	NM	$ —
Written oil puts					
Volumes (MMbtu)	72,000	NM	—	NM	—
Average ceiling price ($ per MMbtu)	$ 34.67	NM	$ —	NM	$ —

See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk — Derivative Instruments and Hedging Activities — Commodity Price Risk" for a description of our derivative contracts and our derivative contracts open at December 31, 2005.

Income taxes: A deferred tax liability or asset is recognized for the estimated future tax effects attributable to (i) NOLs and (ii) existing temporary differences between book and taxable income. Realization of net deferred tax assets is dependent upon generating sufficient taxable income within the carryforward period available under tax law.

In 2003, due to the increased level of capital expenditures resulting from the September 2003 equity offering, we recognized a net deferred tax asset of $1.8 million because we believed we would have reversals of existing temporary differences between book and taxable income sufficient to result in future net deferred tax liabilities. Our $1.8 million net deferred tax asset consisted of a $1.2 million deferred income tax benefit and a $0.6 million tax effect of unrealized hedging losses. In 2003, we believed that it was more likely than not that capital loss carryfowards of approximately $1.8 million would expire unused and, accordingly, we established a valuation allowance of $634,000. The primary reason for the difference between our effective tax rate of 37.4% and the federal statutory rate of 35% was due to the effect of the change in our valuation allowance and deductible stock compensation which were partially offset by hedging losses.

In 2004, we recognized a current year net deferred tax liability of $10.6 million due to reversals of our existing temporary differences between book and taxable income resulting mainly from our capital expenditures. Our $10.6 million net deferred tax liability consisted of a $10.9 million deferred income tax expense, a $0.3 million tax effect of unrealized hedging gains, and a $0.6 million credit to equity for the tax benefit from the exercise of stock options. Our deferred tax expense was due primarily to increased capital expenditures and a $14 million increase in our pre-tax income. The primary reason for the difference between our effective tax rate of 35.6% and the federal statutory rate of 35% was due to the effect of preferred stock dividends which were partially offset by deductible stock compensation.

In 2005, we recognized a current year net deferred tax liability of $14.3 million due to reversals of our existing temporary difference between book and taxable income resulting mainly from our capital expenditures. Our $14.3 million net deferred tax liability consisted of a $15 million increase in our 2005 deferred income tax expense, a $42,000 tax effect of unrealized hedging losses, and a $791,000 credit to equity for the tax benefit from the exercise of stock options. Capital loss carryforwards of approximately $1.6 million expired at the end of 2005, reducing the valuation allowance we established in 2003 by $573,000. The $4.1 million increase in our 2005 deferred tax expense was primarily due to a $12 million increase in capital expenditures and a $12 million increase in our pre-tax income. The primary reason for the difference between our effective tax rate of 35.4% and the federal statutory rate of 35% was due to the effect of preferred stock dividends that were partially offset by deductible stock compensation.

Dividends and accretion of mandatorily redeemable preferred stock. We are required to pay dividends on our Series A preferred stock and were required to pay dividends on our Series B preferred stock. Prior to July 2003, all dividends associated with our Series A and Series B preferred stock were reported as dividends on our Consolidated Statement of Operations. Upon our adoption of SFAS 150 in July 2003, we reclassified approximately $8 million of our then outstanding mandatorily redeemable Series A and Series B preferred stock that must be settled with our assets to long-term debt. As part of the reclassification, the dividends associated with the reclassified amount since July 2003 has been reported as interest expense. For more information on our Series A preferred stock see "— Net interest expense," "Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities — Price Range of Common Stock and Dividend Policy," and "Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities — Recent Issuances of Unregistered Securities — Mandatorily Redeemable Preferred Stock."

Analysis of Changes In Cash and Cash Equivalents

The table below summarizes our sources and uses of cash during 2005, 2004 and 2003.

	Year Ended December 31,				
	2005	% Change	2004	% Change	2003
			(In thousands)		
Net income	$ 27,435	40%	$ 19,650	9%	$ 18,030
Non-cash charges	51,723	42%	36,455	88%	19,357
Changes in working capital and other items	(14,779)	NM	276	(94)%	4,304
Cash flows provided by operating activities	$ 64,379	14%	$ 56,381	35%	$ 41,691
Cash flows used by investing activities	(113,220)	34%	(84,645)	84%	(46,089)
Cash flows provided (used) by financing activities	50,535	104%	24,766	NM	(5,141)
Net increase (decrease) in cash and cash equivalents	$ 1,694	NM	$ (3,498)	(63)%	$ (9,539)

Analysis of net cash provided by operating activities

Net cash provided by operating activities for 2005 was $8 million higher than 2004. This compares to net cash provided by operating activities in 2004 that was $14.7 million higher than 2003.

The following are the primary reasons for the $8 million increase in our 2005 net cash provided by operating activities over 2004.

- An increase in the sales prices we received from the sale of our oil and natural gas in 2005 combined with a decrease in losses related to the cash settlement of derivative contracts in 2005 increased net cash provided by operating activities by $27.2 million. This increase was partially offset by a $2.6 million decline in revenue due to lower production volumes.

- An increase in our production cost and cash general and administrative expenses for 2005 reduced net cash provided by operating activities in by $919,000.
- An increase in the cash interest expense that we paid in 2005 reduced our net cash provided by operating activities in 2005 by $1.3 million.
- The payment of accounts payable in excess of the collection of accounts receivable resulted in a $10.3 million decrease to our 2005 net cash provided by operating activities.
- A decrease in advances paid to us by participants in our 3-D seismic projects and certain wells resulted in $4 million decrease to our 2005 net cash provided by operating activities.

The following are the primary reasons for the $14.7 million increase in our 2004 net cash provided by operating activities.

- Net cash provided by operating activities increased by $20.2 million due to an increase in our production volumes combined with an increase in the prices that we received for oil and natural gas and a decrease in losses on the settlement of our derivative contracts.
- Higher production cost and general and administrative expenses partially offset $2.5 million of this increase.
- The repayment of accounts payable in excess of collections of accounts receivable reduced net cash provided by operating activities by $9.3 million.
- The settlement of the gas imbalance with our industry participant in our Diablo project increased our net cash provided by operating activities by $2.8 million.
- An increase in advances paid to us by participants in our 3-D seismic projects and certain wells increased net cash provided by operating activities by $3.2 million.

Working Capital

Working capital is the amount by which current assets exceed current liabilities. It is normal for us to report a working capital deficit at the end of a period. These deficits are primarily the result of accounts payable related to lease operating expenses, exploration and development costs, royalties payable and gas imbalances payable. Settlement of these payables will be funded by cash flows from operations or, if necessary, by additional borrowing under our senior credit facility.

Our working capital deficit at December 31, 2005 was $9.1 million compared to a working capital deficit of $19.5 million at December 31, 2004. Our working capital deficit at December 31, 2005, included a liability of $2.2 million and an asset of $224,000 related to the fair value of derivative contracts.

Our working capital deficit at December 31, 2004 was $19.5 million compared to a working capital deficit of $14.7 at December 31, 2003. Our working capital deficit at December 31, 2004, included a liability of $870,000 and an asset of $142,000 related to the fair value our derivative contracts.

Analysis of changes in cash flows used by investing activities

Net cash used by investing activities for 2005 was 34% higher than 2004. This compares to a 84% increase in our 2004 net cash used by investing activities over 2003.

The following are the primary reasons for the $28.6 million increase in our 2005 net cash used by investing activities over those in 2004.

- Our additions to oil and natural gas properties for 2005 were up 34% when compared to 2004. The primary reasons for this increase were due to an $18.7 million increase in our drilling capital expenditures net of changes in accrued drilling costs, a $6.6 million increase in our capital expenditures for land and seismic activities and a $1.1 million increase in the amount of interest that we capitalized. The primary reason for these increases was an increase in our capital expenditures for oil and natural gas activities in 2005. Additions to oil and natural gas properties also included a $2 million gas imbalance receivable related to an acquisition of another operators interests in our Triple Crown field. (For more information regarding our capital expenditures for oil and natural gas activities see below.)

- Our capital expenditures for other assets in 2005 were $33,000 lower than 2004.
- Proceeds from the sale of property in 2005 were $83,000 lower than 2004.
- Our prepaid drilling cost at December 31, 2005, which is reported as an asset on our balance sheet, was $405,000 compared to $377,000 at December 31, 2004.

The following are the primary reasons for the $38.6 million increase in our 2004 net cash used by investing activities over those in 2003.

- Our additions to oil and natural gas properties for 2004 were up 84% when compared to 2003. The primary reasons for this increase were due to a $32.1 million increase in our drilling capital expenditures net of changes in accrued drilling costs, a $6.9 million increase in our capital expenditures for land and seismic activities and a $251,000 increase in the amount of general and administrative costs we capitalized. The primary reason for these increases was an increase in our capital expenditures for oil and natural gas activities in 2004. These increases were partially offset by a $681,000 reduction in the amount of interest we capitalized in 2004. (For more information regarding our capital expenditures for oil and natural gas activities see below.)
- Our capital expenditures for other assets in 2004 were $29,000 higher than 2003.
- Proceeds from the sale of property in 2004 were $335,000 lower than 2003.
- Our prepaid drilling cost at December 31, 2004, which was reported as an asset on our balance sheet, were $377,000 compared to $457,000 at December 31, 2003.

The following is a detailed breakout of our capital expenditures for oil and natural gas activities for 2005, 2004 and 2003.

	Year Ended December 31,		
	2005	2004	2003
		(In thousands)	
Cost Incurred:			
Exploration(a)	$ 54,338	$30,327	$20,243
Property acquisition(b)	15,701	6,226	4,850
Development(c)	48,588	50,872	22,437
Costs incurred	$118,627	$87,425	$47,530
Amount spent to develop proved undeveloped reserves	$ 26,568	$34,723	$11,399

(a) Includes capital expenditures for the following

Drilling	$ 44,082	$18,339	$13,586
Land and seismic	5,878	7,991	2,470
Asset retirement obligation	356	138	117
Capitalized cost	4,022	3,859	4,070
	$ 54,338	$30,327	$20,243

(b) Includes capital expenditures for the following

Proved property acquisition	$ 191	$ —	$ —
Unproved property acquisition	13,572	5,002	3,604
Capitalized cost	1,938	1,224	1,246
	$15,701	$ 6,226	$ 4,850

(c) Includes capital expenditures for the following

Drilling	$46,791	$49,866	$21,520
Asset retirement obligation	968	375	152
Capitalized cost	829	631	765
	$48,588	$50,872	$22,437

Analysis of changes in cash flows from financing activities

Over the three year period ended December 31, 2005, we have entered into various financing transactions with the intent of reducing our cost of capital and increasing our liquidity so that we could fund our capital expenditures for the exploration and development of oil and natural gas properties.

Our net cash provided by financing activities in 2005 was $25.8 million higher than in 2004. This compares to net cash provided by financing activities in 2004 that was $29.9 million higher than 2003.

Senior Credit Agreement

Our net borrowings under our senior credit agreement were $10.1 million higher in 2005 than they were in 2004. This compares to a $43 million increase in net borrowings under our senior credit agreement in 2004 when compared to 2003.

During 2005, we borrowed $63.1 million under our senior credit agreement. We used net proceeds from our sale of common stock in November 2005 combined and cash on hand to repay $51 million in borrowings. We paid $675,000 in fees related to the amendment and restatement of our senior credit agreement in 2005.

In 2004, we borrowed $33 million under our senior credit agreement. We used net proceeds from our sale of common stock in July 2004 combined and cash on hand to repay $31 million in borrowings.

Senior Subordinated Notes

Our net borrowings under our subordinated credit agreement were $10 million higher in 2005 than they were in 2004. This compares to a $3 million decrease in net borrowings under our subordinated credit agreement in 2004 when compared to 2003.

During 2005, we borrowed an additional $10 million under our subordinated credit agreement and paid $245,000 in fees related to the amendment of our subordinated credit agreement in 2005.

Common Stock Transactions

Our net proceeds from the sale of common stock and employee stock option exercises during 2005 were $6.1 million higher in 2005 than they were in 2004. This compares to net proceeds that were $17.9 million lower in 2004 than in 2003.

The following is a list of common stock transactions that occurred in 2005, 2004 and 2003.

	Shares Issued	Net Proceeds
	(In thousands except share data)	
2005 common stock transactions:		
Sale of common stock under universal shelf registration statement(a)	2,500,000	$28,321
Exercise of employee stock options	340,467	$ 1,314
2004 common stock transactions:		
Sale of common stock under universal shelf registration statement(b)	2,598,500	$22,105
Exercise of employee stock options	314,181	972
2003 common stock transactions:		
Sale of common stock(c)	7,384,090	$40,000
Exercise of employee stock options	309,760	829

(a) The net proceeds from the sale were used to repay debt outstanding under our senior credit agreement. Net proceeds does not include the net proceeds from the sale of common stock used to purchase 6,125,000 shares of our stock held by funds managed by affiliates of Credit Suisse First Boston (USA), Inc.

(b) The net proceeds from the sale were used to repay debt outstanding under our senior credit agreement.

(c) The net proceeds from the sale were used to accelerate the amount of capital that we spent on our exploration and development program and reduce our outstanding debt.

For additional shares issued where we did not receive proceeds, see "Item 5. Market for Registrant's Common Equity and Related Stockholder Matters and Issuer Purchases of Equity Securities — Recent Issuance of Unregistered Securities."

Mandatorily Redeemable Preferred Stock

In 2003, we redeemed $704,000 of our Series B mandatorily redeemable preferred stock that remained outstanding after CSFB converted a majority of its Series B preferred stock to common stock.

Other Matters

Derivative Instruments

Our results of operations and operating cash flow are impacted by changes in market prices for oil and gas. We believe the use of derivative instruments, although not free of risk, allows us to reduce our exposure to oil and natural gas sales price fluctuations and thereby achieve a more predictable cash flow. While the use of derivative instruments limits the downside risk of adverse price movements, their use may also limit future revenues from favorable price movements. Moreover, our derivative contracts generally do not apply to all of our production and thus provide only partial price protection against declines in commodity prices. We expect that the amount of our derivative contracts will vary from time to time. See "Item 1A. Risk Factors — Our hedging activities may prevent us from benefiting from price increases and may expose us to other risks" and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

Effects of Inflation and Changes in Prices

Our results of operations and cash flows are affected by changing oil and natural gas prices. If the price of oil and natural gas increases (decreases), there could be a corresponding increase (decrease) in revenues as well as the operating costs that we are required to bear for operations. Inflation has had a minimal effect on us.

Environmental and Other Regulatory Matters

Our business is subject to certain federal, state and local laws and regulations relating to the exploration for and the development, production and marketing of oil and natural gas, as well as environmental and safety matters. Many of these laws and regulations have become more stringent in recent years, often imposing greater liability on a larger number of potentially responsible parties. Although we believe that we are in substantial compliance with all applicable laws and regulations, the requirements imposed by laws and regulations are frequently changed and subject to interpretation, and we cannot predict the ultimate cost of compliance with these requirements or their effect on our operations. Any suspensions, terminations or inability to meet applicable bonding requirements could materially adversely affect our financial condition and operations. Although significant expenditures may be required to comply with governmental laws and regulations applicable to us, compliance has not had a material adverse effect on our earnings or competitive position. Future regulations may add to the cost of, or significantly limit, drilling activity. See "Item 1A. Risk Factors — We are subject to various governmental regulations and environmental risks that may cause us to incur substantial costs" and "Item 1. Business — Governmental Regulation" and "Item 1. Business — Environmental Matters."

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

Management Opinion Concerning Derivative Instruments

We use derivative instruments to manage exposure to commodity prices and interest rate risks. Our objectives for holding derivatives are to achieve a consistent level of cash flow to support a portion of our planned capital spending. Our use of derivative instruments for hedging activities could materially affect our results of operations in particular quarterly or annual periods since such instruments can limit our ability to benefit from favorable price movements. We do not enter into derivative instruments for trading purposes.

Fair Value of Derivative Contracts

The fair value of our derivative contracts is determined based on counterparties' estimates and valuation models. We did not change our valuation methodology during the year ended December 31, 2005. During 2005, we were party to natural gas swap contracts, natural gas three-way costless collars, oil swaps, oil collar contracts and interest rate swaps. See "Notes to the Consolidated Financial Statements — Note 10" for additional information regarding our derivative contracts. The following table reconciles the changes that occurred in the fair values of our open derivative contracts during 2005.

	Fair Value of Undesignated Derivative Contracts	Fair Value of Cash Flow Derivative Contracts	Total
	(In thousands)		
Estimated fair value of open contracts at December 31, 2004	$ (34)	$ (692)	$ (726)
Changes in fair values of derivative contracts:			
Natural gas collars	$ (66)	$(2,469)	$(2,535)
Oil collars	(25)	(372)	(397)
Interest rate swap	—	642	642
Settlements of derivative contracts that were open at December 31, 2004:			
Natural gas collars	$ —	$ 670	$ 670
Oil collars	—	926	926
Interest rate swap	—	—	—
Estimated fair value of open contracts at December 31, 2005	$(125)	$(1,295)	$(1,420)

Based upon the market prices at December 31, 2005, we expect to transfer approximately $2.0 million of the loss included on our balance sheet in accumulated other comprehensive income (loss) to earnings during the next twelve months when transactions actually occur.

Derivative Instruments and Hedging Activities

We believe the use of derivative instruments, although not free of risk, allows us to reduce our exposure to oil and natural gas sales price fluctuations and thereby achieve a more predictable cash flow. While the use of derivative instruments limits the downside risk of adverse price movements, their use may also limit future revenues from favorable price movements. Moreover, our derivative contracts generally do not apply to all of our production and thus provide only partial price protection against declines in commodity prices. We expect that the amount of our derivative contracts will vary from time to time.

The gas derivative transactions are generally settled based upon the average of the reporting settlement prices on the NYMEX for the last three trading days of a particular contract month. The oil derivative transactions are generally settled based on the average reporting settlement prices on the NYMEX for each trading day of a particular calendar month.

Our primary commodity market risk exposure is to changes in the prices related to the sale of our oil and natural gas production. The market prices for oil and natural gas have been volatile and are likely to continue to be volatile in the future. As such, we employ established policies and procedures to manage our exposure to fluctuations in the sales prices we receive for our oil and natural gas production using derivative instruments.

Cash Flow Hedges

Our derivative contracts accounted for as cash flow hedges consisted of fixed-price swaps, costless collars (purchased put options and written call options) and the costless collar portion of a three-way costless collar (purchased put, written put options and written call options).

Our fixed-price swap contracts are used to fix the sales price for our anticipated future oil and natural gas production. Upon settlement, we receive a fixed price for the hedged commodity and pay our counterparty a floating market price, as defined in each instrument. These instruments are settled monthly. When the floating price exceeds the fixed price for a contract month, we pay our counterparty. When the fixed price exceeds the floating price, our counterparty is required to make a payment to us. We have designated theses contracts as cash flow hedges designed to achieve a more predictable cash flow, as well as reduce our exposure to price volatility.

We use costless collars to establish floor (purchased put option) and ceiling price (written call option) on our anticipated future oil and natural gas production. We receive no net premiums when we enter into these option arrangements. These contracts are settled monthly. When the settlement price for a period is above the ceiling price (written call option), we pay our counterparty. When the settlement price for a period is below the floor price (purchased put option), our counterparty is required to pay us. We have designated these collar instruments as cash flow hedges designed to achieve a more predictable cash flow, as well as reduce our exposure to price volatility.

A three-way costless collar consists of a costless collar (purchased put option and written call option) plus a put (written put) sold by us with a price below the floor price (purchased put option) of the costless collar. We receive no net premiums when we entered into these option arrangements. These contracts are settled monthly. The written put requires us to make a payment to our counterparty if the settlement price for a period is below the written put price. Combining the costless collar (purchased put option and written call option) with the written put results in us being entitled to a net payment equal to the difference between the floor price (purchased put option) of the costless collar and the written put price if the settlement price is equal to or less than the written put price. If the settlement price is greater than the written put price, the result is the same as it would have been with a costless collar. This strategy enables us to increase the floor and the ceiling price of the collar beyond the range of a traditional costless collar while offsetting the associated cost with the sale of the written put. The put that we sell is not designated as a cash flow hedge.

Derivatives Not Designated as Hedges

Our derivative positions included written put options that are not designated as hedges and are reported at fair value on our balance sheet. These contracts were entered into in conjunction with a costless collar to offset the cost of other option positions that are designated as hedges.

The following table reflects our open derivative contracts at December 31, 2005, the associated volumes and the corresponding weighted average NYMEX reference price.

Settlement Period	Derivative Instrument	Hedge Strategy	Notional Amount Gas (MMBTU)	Notional Amount Oil (Barrels)	Nymex Reference Price
Costless Collars					
01/01/06 — 03/31/06	Purchased put	Cash flow		7,500	$ 62.00
	Written call	Cash flow		7,500	74.50
04/01/06 — 10/31/06	Purchased put	Cash flow	490,000		$ 8.00
	Written call	Cash flow	490,000		14.85
04/01/06 — 06/30/06	Purchased put	Cash flow		16,500	$ 54.80
	Written call	Cash flow		16,500	75.00
04/01/06 — 7/31/06	Purchased put	Cash flow	360,000		$ 8.00
	Written call	Cash flow	360,000		15.60
04/01/06 — 7/31/06	Purchased put	Cash flow	360,000		$ 8.00
	Written call	Cash flow	360,000		17.00
04/01/06 — 09/30/06	Purchased put	Cash flow		42,000	$ 50.00
	Written call	Cash flow		42,000	75.60
11/01/06 — 03/31/07	Purchased put	Cash flow	450,000		$ 8.00
	Written call	Cash flow	450,000		21.20
08/01/06 — 10/31/06	Purchased put	Cash flow	360,000		$ 8.00
	Written call	Cash flow	360,000		16.65
10/01/06 — 12/31/06	Purchased put	Cash flow		27,000	$ 50.00
	Written call	Cash flow		27,000	77.50
11/01/06 — 01/31/07	Purchased put	Cash flow	540,000		$ 8.00
	Written call	Cash flow	540,000		23.25
01/01/07 — 03/31/07	Purchased put	Cash flow		24,000	$ 50.00
	Written call	Cash flow		24,000	78.25
Three Way Costless Collars					
01/01/06 — 3/31/06	Purchased put	Cash flow	150,000		$ 6.75
	Written call	Cash flow	150,000		8.80
	Written put	Undesignated	150,000		5.50
01/01/06 — 3/31/06	Purchased put	Cash flow	210,000		$ 8.00
	Written call	Cash flow	210,000		9.75
	Written put	Undesignated	210,000		6.50
01/01/06 — 3/31/06	Purchased put	Cash flow	240,000		$ 10.00
	Written call	Cash flow	240,000		13.08
	Written put	Undesignated	240,000		8.50
01/01/06 — 3/31/06	Purchased put	Cash flow		18,000	$ 48.00
	Written call	Cash flow		18,000	60.70
	Written put	Undesignated		18,000	38.00
04/01/06 — 10/31/06	Purchased put	Cash flow	420,000		$ 7.50
	Written call	Cash flow	420,000		9.15
	Written put	Undesignated	420,000		6.25
04/01/06 — 10/31/06	Purchased put	Cash flow	490,000		$ 8.50
	Written call	Cash flow	490,000		9.96
	Written put	Undesignated	490,000		7.00

Settlement Period	Derivative Instrument	Hedge Strategy	Notional Amount Gas (MMBTU)	Notional Amount Oil (Barrels)	Nymex Reference Price
04/01/06 — 6/30/06	Purchased put	Cash flow		7,500	$ 63.00
	Written call	Cash flow		7,500	75.25
	Written put	Undesignated		7,500	48.00
07/01/06 — 9/30/06	Purchased put	Cash flow		15,000	$ 63.00
	Written call	Cash flow		15,000	75.65
	Written put	Undesignated		15,000	48.00

Interest Rate Risk

At December 31, 2005, we had $73.2 million of debt, of which $30.1 million was fixed rate debt. Our fixed rate debt consists of $20 million notes outstanding under our subordinated credit agreement and $10.1 million in mandatorily redeemable Series A preferred stock. The remaining $43.1 million of debt we had outstanding at December 31, 2005, was floating rate debt, which consisted of $33.1 million of debt outstanding our senior credit agreement and $10 million of debt outstanding under our subordinated credit agreement.

The interest rate that we pay on amounts borrowed under our senior credit agreement is derived from the Eurodollar rate and a margin that is applied to the Eurodollar rate. This calculation was performed using the one month Eurodollar rate on December 30, 2005 which was 4.39%. The margin that we pay is based upon the percentage of our available borrowing base that we utilize at the beginning of the quarter. At December 31, 2005, the borrowing base for our senior credit agreement was $90 million. Since the amount that we had borrowed under our senior credit at December 31, 2005 was $33.1 million, we were utilizing approximately 37% of our available borrowing base. At this level of borrowing, our senior credit agreement requires us to pay a margin of 1.25%, thus the interest rate that we would be required to pay on the amounts borrowed under our senior credit facility would be 5.64%. A 10% increase in the Eurodollar rate would equal approximately 44 basis points. Such an increase in the Eurodollar rate would change our annual interest expense by approximately $145,000, assuming borrowed amounts under our senior credit facility remain at $33.1 million.

At December 31, 2005, we had $30 million in borrowings outstanding under our subordinated credit agreement. The interest rate that we pay on $20 million of these borrowings is fixed at 7.61% using an interest rate swap. The interest rate on the remaining $10 million is as floating interest rate. The interest rate that we pay on the portion of our subordinated credit agreement that is subject to a floating interest rate is derived from the 3 month Eurodollar rate and a margin that is applied to the Eurodollar rate. This calculation was performed using the three month Eurodollar rate on December 30, 2005 which was 4.54%. The margin that we pay on the amounts borrowed under our subordinated credit agreement is based upon the amount of debt we have outstanding under our subordinated credit agreement and the percentage of the borrowing base for our senior credit agreement that we utilize. At December 31, 2005, we had $30 million in borrowings outstanding under our subordinated credit agreement and were utilizing approximately 37% of the borrowing base for our senior credit agreement. At this level of borrowing, our subordinated credit agreement requires us to pay a margin of 3.9%, thus, the interest rate that we would be required to pay on the $10 million borrowed under our subordinated credit agreement that is subject to floating interest rate would be 8.44%. A 10% increase in the Eurodollar rate would equal approximately 45 basis points and would change the interest expense that we pay on the $10 million of floating rate debt by approximately $45,000. This calculation assumes that the amounts borrowed under our subordinated credit agreement and our senior credit agreement remain the same.

The estimated fair value of our senior subordinated notes at December 31, 2005, was $29.4 million.

We are required to pay the dividends on our Series A preferred stock in cash at a rate of 6% per annum. The fair value of the Series A mandatorily redeemable preferred stock at December 31, 2005 was approximately $8.9 million.

Item 8. *Financial Statements and Supplementary Data*

Our Consolidated Financial Statements required by this item are included on the pages immediately following the Index to Financial Statements appearing on page F-1.

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

None.

Item 9A. *Controls and Procedures*

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of December 31, 2005, our management, including our principal executive officer and principal financial officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Based upon and as of the date of the evaluation, our principal executive officer and our principal financial officer concluded that the design and operation of our disclosure controls and procedures were effective at a reasonable assurance level.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our 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 (COSO). Based on our evaluation under the framework in *Internal Control — Integrated Framework* issued by the COSO, our management concluded that our internal control over financial reporting was effective as of December 31, 2005.

Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Changes in Internal Control over Financial Reporting

There has been no change in our internal control over financial reporting during the fourth quarter of 2005 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. ***Directors and Executive Officers of the Registrant***

The information required by this item is incorporated by reference to information under the caption "Proposal One — Election of Directors", the information under the caption "Section 16(a) Beneficial Ownership Reporting Compliance" and the information under the caption "Corporate Governance — Code of Business Conducted and Ethics" in our 2006 Proxy Statement for our annual meeting of stockholders to be held on Thursday, June 1, 2006. The 2006 Proxy Statement will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2005.

Pursuant to Item 401(b) of Regulation S-K, the information required by this item with respect to Brigham's executive officers is set forth in Part I of this report.

Item 11. ***Executive Compensation***

The information required by this item is incorporated herein by reference to the 2006 Proxy Statement, which will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2005.

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

The information required by this item is incorporated herein by reference to the 2006 Proxy Statement, which will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2005. See "Item 5. Market for Registrants Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities," which sets forth certain information with respect to our equity compensation plans.

Item 13. ***Certain Relationships and Related Transactions***

The information required by this item is incorporated herein by reference to the 2006 Proxy Statement, which will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2005.

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

The information required by this item is incorporated herein by reference to the 2006 Proxy Statement, which will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2005.

PART IV

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

(a)1. Consolidated Financial Statements: See Index to Financial Statements on page F-1.

2. No schedules are required.

3. Exhibits:

The exhibits listed in the accompanying Index to Exhibits are filed or incorporated by reference as part of the annual report.

GLOSSARY OF OIL AND GAS TERMS

The following are abbreviations and definitions of certain terms commonly used in the oil and gas industry and in this report. The definitions of proved developed reserves, proved reserves and proved undeveloped reserves have been abbreviated from the applicable definitions contained in Rule 4-10(a)(2-4) of Regulation S-X.

3-D seismic. The method by which a three dimensional image of the earth's subsurface is created through the interpretation of reflection seismic data collected over surface grid. 3-D seismic surveys allow for a more detailed understanding of the subsurface than do conventional surveys and contribute significantly to field appraisal, development and production.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to oil or other liquid hydrocarbons.

Bcfe. One billion cubic feet of natural gas equivalent. In reference to natural gas, natural gas equivalents are determined using the ratio of 6 Mcf of natural gas to 1 Bbl of oil, condensate or natural gas liquids.

Completion. The installation of permanent equipment for the production of oil or natural gas. Completion of the well does not necessarily mean the well will be profitable.

Completion Rate. The number of wells on which production casing has been run for a completion attempt as a percentage of the number of wells drilled.

Developed Acreage. The number of acres which are allocated or assignable to producing wells or wells capable of production.

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

Dry Well. A well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion of an oil or gas well.

Exploratory Well. A well drilled to find and produce oil or natural gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir.

Fault. A break in the rocks along which there has been movement of one side relative to the other side.

Fault Block. A body of rocks bounded by one or more faults.

Gross Acres or Gross Wells. The total acres or wells, as the case may be, in which we have a working interest.

Lease Operating Expenses. The expenses, usually recurring, which pay for operating the wells and equipment on a producing lease.

MBbl. One thousand barrels of oil or other liquid hydrocarbons.

Mcf. One thousand cubic feet of natural gas.

MMBbl. One million barrels of oil or other liquid hydrocarbons.

Mcfe. One thousand cubic feet of natural gas equivalents.

MMBtu. One million Btu, or British Thermal Units. One British Thermal Unit is the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

MMcf. One million cubic feet of natural gas.

Mmcfe. One million cubic feet of natural gas equivalents.

Mmcfe/d. Mmcfe per day.

Net Acres or Net Wells. Gross acres or wells multiplied, in each case, by the percentage working interest we own.

Net Production. Production that we own less royalties and production due others.

Oil. Crude oil, condensate or other liquid hydrocarbons.

Operator. The individual or company responsible for the exploration, development, and production of an oil or gas well or lease.

Pay. The vertical thickness of an oil and gas producing zone. Pay can be measured as either gross pay, including non-productive zones or net pay, including only zones that appear to be productive based upon logs and test data.

Pre-tax PV10%. The pre-tax present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with Securities and Exchange Commission guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to 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%.

Proved Developed Reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved Reserves. 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 Undeveloped Reserves. 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.

Royalty. An interest in an oil and gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

Spud. Start drilling a new well (or restart).

Standardized Measure. The after-tax present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with Securities and Exchange Commission guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to 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%.

Trend. A geographical area that has been known to contain certain types of combinations of reservoir rock, sealing rock and trap types containing commercial amounts of hydrocarbons.

Working Interest. An interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce oil and natural gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations.

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, hereunder duly authorized, as of February 27, 2006.

BRIGHAM EXPLORATION COMPANY

By /s/ BEN M. BRIGHAM

Ben M. Brigham
Chief Executive Officer, President and Chairman of the Board

Pursuant to the requirements of the Securities Exchange Act of 1934, the following persons on behalf of the Registrant and in the capacity indicated have signed this report below as of February 27, 2006.

/s/ BEN M. BRIGHAM Ben M. Brigham	Chief Executive Officer, President and Chairman of the Board (Principal Executive Officer)
/s/ EUGENE B. SHEPHERD, JR. Eugene B. Shepherd, Jr.	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)
/s/ DAVID T. BRIGHAM David T. Brigham	Executive Vice President — Land and Administration and Director
/s/ HAROLD D. CARTER Harold D. Carter	Director
/s/ STEPHEN C. HURLEY Stephen C. Hurley	Director
/s/ STEPHEN P. REYNOLDS Stephen P. Reynolds	Director
/s/ HOBART A. SMITH Hobart A. Smith	Director
/s/ STEVEN A. WEBSTER Steven A. Webster	Director
/s/ R. GRAHAM WHALING R. Graham Whaling	Director

BRIGHAM EXPLORATION COMPANY

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Brigham Exploration Company:

We have completed integrated audits of Brigham Exploration Company's 2005 and 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2005, and an audit of its 2003 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Brigham Exploration Company and its subsidiaries at December 31, 2005 and December 31, 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements 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 of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1, the Company adopted Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" on January 1, 2003.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A, that the Company maintained effective internal control over financial reporting as of December 31, 2005 based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control — Integrated Framework* issued by the COSO. 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 opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting 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. An audit of internal control over financial reporting includes 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 consider 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 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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) 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 its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 27, 2006

BRIGHAM EXPLORATION COMPANY
CONSOLIDATED BALANCE SHEETS

	December 31, 2005	December 31, 2004
	(In thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 3,975	$ 2,281
Accounts receivable	22,825	17,573
Deferred income taxes	482	239
Other current assets	1,043	901
Total current assets	28,325	20,994
Oil and natural gas properties, using the full cost method of accounting		
Proved	483,760	355,834
Unproved	38,048	47,356
Accumulated depletion	(174,479)	(141,211)
	347,329	261,979
Other property and equipment, net	1,027	1,209
Deferred loan fees	2,174	1,745
Other noncurrent assets	1,572	380
Total assets	$ 380,427	$ 286,307
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 12,128	$ 22,465
Royalties payable	6,886	6,072
Accrued drilling costs	12,218	6,099
Participant advances received	2,116	3,633
Other current liabilities	4,119	2,225
Total current liabilities	37,467	40,494
Senior credit facility	33,100	21,000
Senior subordinated notes	30,000	20,000
Series A Preferred Stock, mandatorily redeemable, \$.01 par value, \$20 stated and redemption value, 2,250,000 shares authorized, 505,051 and 475,986 shares issued and outstanding at December 31, 2005 and 2004, respectively	10,101	9,520
Deferred income taxes	23,563	9,031
Other noncurrent liabilities	4,556	2,986
Commitments and contingencies (Note 9)		
Stockholders' equity:		
Common stock, \$.01 par value, 50 million shares authorized, 44,917,768 and 43,231,499 shares issued and 44,917,768 and 42,034,351 shares outstanding at December 31, 2005 and 2004, respectively	449	432
Additional paid-in capital	202,127	175,270
Treasury stock, at cost; 1,197,148 shares at December 31, 2004	—	(4,707)
Unearned stock compensation	(2,299)	(1,570)
Accumulated other comprehensive income (loss)	(426)	(503)
Retained earnings	41,789	14,354
Total stockholders' equity	241,640	183,276
Total liabilities and stockholders' equity	$ 380,427	$ 286,307

The accompanying notes are an integral part of these consolidated financial statements.

BRIGHAM EXPLORATION COMPANY

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2005	2004	2003
	(In thousands, except per share data)		
Revenues:			
Oil and natural gas sales	$ 96,820	$ 71,713	$ 51,545
Other revenue	220	515	132
	97,040	72,228	51,677
Costs and expenses:			
Lease operating	7,161	6,173	5,200
Production taxes	3,353	3,107	2,477
General and administrative	5,533	5,392	4,500
Depletion of oil and natural gas properties	33,268	23,844	16,819
Depreciation and amortization	762	722	629
Accretion of discount on asset retirement obligations	180	159	142
	50,257	39,397	29,767
Operating income	46,783	32,831	21,910
Other income (expense):			
Interest income	245	84	45
Interest expense, net	(3,980)	(3,144)	(4,815)
Other income (expense)	(576)	742	(601)
	(4,311)	(2,318)	(5,371)
Income before income taxes and cumulative effect of change in accounting principle	42,472	30,513	16,539
Income tax benefit (expense):			
Current	—	—	—
Deferred	(15,037)	(10,863)	1,223
	(15,037)	(10,863)	1,223
Income before cumulative effect of change in accounting principle	27,435	19,650	17,762
Cumulative effect of change in accounting principle, net of taxes	—	—	268
Net income	27,435	19,650	18,030
Less accretion and dividends on redeemable preferred stock	—	—	3,448
Net income (loss) available to common stockholders	$ 27,435	$ 19,650	$ 14,582
Net income (loss) per share available to common stockholders:			
Basic:			
Income before cumulative effect of change in accounting principle	$ 0.65	$ 0.49	$ 0.62
Cumulative effect of change in accounting principle	—	—	0.01
	$ 0.65	$ 0.49	$ 0.63
Diluted:			
Income before cumulative effect of change in accounting principle	$ 0.63	$ 0.47	$ 0.51
Cumulative effect of change in accounting principle	—	—	0.01
	$ 0.63	$ 0.47	$ 0.52
Weighted average common shares outstanding:			
Basic	42,481	40,445	23,363
Diluted	43,728	41,616	34,354

The accompanying notes are an integral part of these consolidated financial statements.

BRIGHAM EXPLORATION COMPANY

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Stock Shares	Common Stock Amounts	Additional Paid In Capital	Treasury Stock	Unearned Stock Compensation	Accumulated Other Comprehensive Income (Loss)	Retained Earnings (Accumulated Deficit)	Total Stockholders Equity
					(In thousands)			
Balance, December 31, 2002	20,618	$206	$ 93,436	$(4,282)	$ (212)	$(3,047)	$(23,326)	$ 62,775
Comprehensive income (loss):								
Net income	—	—	—	—	—	—	18,030	18,030
Unrealized gains on cash flow hedges	—	—	—	—	—	991	—	991
Tax benefits related to cash flow hedges	—	—	—	—	—	561	—	561
Net losses included in net income	—	—	—	—	—	455	—	455
Comprehensive income								20,037
Issuance of common stock	7,384	74	39,926	—	—	—	—	40,000
Issuance of restricted stock	—	—	1,831	—	(1,831)	—	—	—
Issuance of stock options	—	—	296	—	(296)	—	—	—
Exercise of employee stock options	310	3	826	—	—	—	—	829
Expiration of employee stock options	—	—	(19)	—	—	—	—	(19)
Forfeitures of restricted stock	—	—	—	(10)	2	—	—	(8)
Repurchases of common stock	—	—	—	(110)	—	—	—	(110)
Warrants exercised for common stock	11,935	119	18,415	—	—	—	—	18,534
In kind dividends on Series A mandatorily redeemable preferred stock	—	—	(2,350)	—	—	—	—	(2,350)
Accretion on Series A mandatorily redeemable preferred stock	—	—	(355)	—	—	—	—	(355)
In kind dividends on Series B mandatorily redeemable preferred stock	—	—	(711)	—	—	—	—	(711)
Accretion on Series B mandatorily redeemable preferred stock	—	—	(32)	—	—	—	—	(32)
Amortization of unearned stock compensation	—	—	—	—	521	—	—	521
Balance, December 31, 2003	40,247	$402	$151,263	$(4,402)	$(1,816)	$(1,040)	$ (5,296)	$139,111
Comprehensive income (loss):								
Net income	—	—	—	—	—	—	19,650	19,650
Unrealized gains on cash flow hedges	—	—	—	—	—	1,485	—	1,485
Tax provisions related to cash flow hedges	—	—	—	—	—	(290)	—	(290)
Net gains included in net income	—	—	—	—	—	(658)	—	(658)
Comprehensive income								20,187
Issuance of common stock	2,598	26	22,079	—	—	—	—	22,105
Issuance of restricted stock	—	—	514	—	(514)	—	—	—
Vesting of restricted stock	72	1	(1)	—	—	—	—	—
Exercise of employee stock options	314	3	969	—	—	—	—	972
Forfeitures of restricted stock	—	—	(131)	(4)	131	—	—	(4)
Tax benefit from the exercise of stock options	—	—	577	—	—	—	—	577
Repurchases of common stock	—	—	—	(301)	—	—	—	(301)
Amortization of unearned stock compensation	—	—	—	—	629	—	—	629
Balance, December 31, 2004	43,231	$432	$175,270	$(4,707)	$(1,570)	$ (503)	$ 14,354	$183,276
Comprehensive income (loss):								
Net income	—	—	—	—	—	—	27,435	27,435
Unrealized losses on cash flow hedges	—	—	—	—	—	(603)	—	(603)
Tax provisions related to cash flow hedges	—	—	—	—	—	(43)	—	(43)
Net losses included in net income	—	—	—	—	—	723	—	723
Comprehensive income								27,512
Issuance of common stock	2,500	25	28,206	—	—	—	—	28,231
Issuance of restricted stock	—	—	1,435	—	(1,435)	—	—	—
Vesting of restricted stock	65	1	(1)	—	—	—	—	—
Exercise of employee stock options	340	3	1,311	—	—	—	—	1,314
Tax benefit from the exercise of stock options	—	—	791	—	—	—	—	791
Repurchases of common stock	—	—	—	(190)	—	—	—	(190)
Retirement of treasury stock	(1,218)	(12)	(4,885)	4,897	—	—	—	—
Amortization of unearned stock compensation	—	—	—	—	706	—	—	706
Balance, December 31, 2005	44,918	$449	$202,127	$ —	$(2,299)	$ (426)	$ 41,789	$241,640

The accompanying notes are an integral part of these consolidated financial statements.

BRIGHAM EXPLORATION COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2005	2004	2003
	(In thousands)		
Cash flows from operating activities:			
Net income	$ 27,435	$19,650	$18,030
Adjustments to reconcile net income to cash provided (used) by operating activities:			
Depletion of oil and natural gas properties	33,268	23,844	16,819
Depreciation and amortization	762	722	629
Interest paid through issuance of additional senior subordinated notes	—	—	1,196
Interest paid through issuance of additional mandatorily redeemable preferred stock	581	726	340
Amortization of deferred loan fees	491	766	1,053
Accretion of discount on asset retirement obligations	180	159	142
Market value adjustment for derivative instruments	814	(625)	669
Deferred income taxes	15,037	10,863	(1,223)
Provision for doubtful accounts	456	—	—
Other noncash items	134	—	—
Cumulative effect of change in accounting principle	—	—	(268)
Changes in working capital and other items:			
Accounts receivable	(3,766)	(6,430)	218
Other current assets	(61)	2,848	3,037
Accounts and royalties payable	(9,456)	3,451	6,092
Other current liabilities	(989)	552	(4,975)
Noncurrent assets	(514)	—	—
Noncurrent liabilities	7	(145)	(68)
Net cash provided by operating activities	64,379	56,381	41,691
Cash flows from investing activities:			
Additions to oil and natural gas properties	(112,856)	(84,439)	(45,842)
Proceeds from sale of oil and natural gas properties	9	92	427
Additions to other property and equipment	(345)	(378)	(349)
(Increase) decrease in drilling advances paid	(28)	80	(325)
Net cash used by investing activities	(113,220)	(84,645)	(46,089)
Cash flows from financing activities:			
Proceeds from issuance of common stock, net of issuance costs	28,231	22,105	40,000
Redemption of Series B mandatorily redeemable preferred stock	—	—	(704)
Proceeds from issuance of senior subordinated notes and warrants	10,000	—	—
Proceeds from exercise of employee stock options	1,314	972	829
Repurchases of common stock	(190)	(301)	(110)
Increase in senior credit facility	63,100	33,000	6,000
Repayment of senior credit facility	(51,000)	(31,000)	(47,000)
Principal payments on senior subordinated notes	—	—	(2,993)
Deferred loan fees paid	(920)	(10)	(1,163)
Net cash provided (used) by financing activities	50,535	24,766	(5,141)
Net increase (decrease) in cash and cash equivalents	1,694	(3,498)	(9,539)
Cash and cash equivalents, beginning of year	2,281	5,779	15,318
Cash and cash equivalents, end of year	$ 3,975	$ 2,281	$ 5,779

The accompanying notes are an integral part of these consolidated financial statements.

BRIGHAM EXPLORATION COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Nature of Operations

Brigham Exploration Company is a Delaware corporation formed on February 25, 1997 for the purpose of exchanging its common stock for the common stock of Brigham, Inc. and the partnership interests of Brigham Oil & Gas, L.P. (the "Partnership"). Hereinafter, Brigham Exploration Company and the Partnership are collectively referred to as "Brigham." Brigham, Inc. is a Nevada corporation whose only asset is its ownership interest in the Partnership. The Partnership was formed in May 1992 to explore and develop onshore domestic oil and natural gas properties using 3-D seismic imaging and other advanced technologies. Since its inception, the Partnership has focused its exploration and development of oil and natural gas properties primarily in the onshore Gulf Coast, the Anadarko Basin and West Texas.

Summary of Significant Accounting Policies

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates relate to proved oil and natural gas reserve volumes and the future development costs, estimates relating to certain oil and natural gas revenues and expenses and deferred income taxes. Actual results may differ from those estimates.

Principles of Consolidation

The accompanying financial statements include the accounts of Brigham and its wholly owned subsidiaries, and its proportionate share of assets, liabilities and income and expenses of the limited partnerships in which Brigham, or any of its subsidiaries has a participating interest. All significant intercompany accounts and transactions have been eliminated.

Cash and Cash Equivalents

Brigham considers all highly liquid financial instruments with an original maturity of three months or less to be cash equivalents.

Property and Equipment

Brigham uses the full cost method of accounting for oil and natural gas properties. Under this method, all acquisition, exploration and development costs, including certain payroll, asset retirement costs, other internal costs, and interest incurred for the purpose of finding oil and natural gas reserves, are capitalized. Internal costs capitalized are directly attributable to acquisition, exploration and development activities and do not include costs related to production, general corporate overhead or similar activities. Costs associated with production and general corporate activities are expensed in the period incurred.

Proceeds from the sale of oil and natural gas properties are applied to reduce the capitalized costs of oil and natural gas properties unless the sale would significantly alter the relationship between capitalized costs and proved reserves, in which case a gain or loss is recognized.

Capitalized costs associated with impaired properties and capitalized costs related to properties having proved reserves, plus the estimated future development costs, asset retirement costs under Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (SFAS 143) are amortized using the unit-of-production method based on proved reserves. Capitalized costs of oil and natural gas properties, net of accumulated amortization, are limited to the total of estimated future net cash flows from proved oil and natural gas reserves, discounted at ten percent, plus the cost of unevaluated properties. There are many factors, including global events that may influence the production, processing, marketing and the price of oil and natural gas. A reduction in the valuation of oil and natural gas properties resulting from declining prices or production could adversely impact depletion rates and capitalized cost limitations. Capitalized costs associated with properties that have not been evaluated through drilling or seismic analysis, including exploration wells in progress at December 31, are excluded from the unit-of-production amortization. Exclusions are adjusted annually based on drilling results and interpretative analysis.

Other property and equipment, which primarily consists of 3-D seismic interpretation workstations, is depreciated on a straight-line basis over the estimated useful lives of the assets after considering salvage value. Estimated useful lives are as follows:

Furniture and fixtures	10 years
Machinery and equipment	5 years
3-D seismic interpretation workstations and software	3 years

Betterments and major improvements that extend the useful lives are capitalized while expenditures for repairs and maintenance of a minor nature are expensed as incurred.

Revenue Recognition

Brigham recognizes revenues from the sale of oil using the sales method of accounting. Under this method, Brigham recognizes revenues when oil is delivered and title transfers.

Brigham recognizes revenues from the sale of natural gas using the entitlements method of accounting. Under this method, revenues are recognized based on Brigham's entitled ownership percentage of sales of natural gas to purchasers. Gas imbalances occur when Brigham sells more or less than its entitled ownership percentage of total natural gas production. When Brigham receives less than its entitled share, a receivable is recorded. When Brigham receives more than its entitled share, a liability is recorded.

Derivative Instruments and Hedging Activities

Brigham uses derivative instruments to manage market risks resulting from fluctuations in the prices of oil and natural gas. Brigham periodically enters into derivative contracts, including price swaps, caps and floors, which require payments to (or receipts from) counterparties based on the differential between a fixed price and a variable price for a fixed quantity of oil or natural gas without the exchange of underlying volumes. The notional amounts of these financial instruments are based on expected production from existing wells.

Derivatives are recorded on the balance sheet at fair value and changes in the fair value of derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as part of a hedge transaction and, if it is, depending on the type of hedge transaction. Brigham's derivatives consist primarily of cash flow hedge transactions in which Brigham is hedging the variability of cash flows related to a forecasted transaction. Period to period changes in the fair value of derivative instruments designated as cash flow hedges are reported in other comprehensive income and reclassified to earnings in the periods in which the contracts are settled. The ineffective portion of the cash flow hedges is recognized in current period earnings as other income (expense). Gains and losses on derivative instruments that do not qualify for hedge accounting are included in other income (expense) in the period in which they occur. The resulting cash flows from derivatives are reported as cash flows from operating activities.

At the inception of a derivative contract, Brigham may designate the derivative as a cash flow hedge. For all derivatives designated as cash flow hedges, Brigham formally documents the relationship between the derivative contract and the hedged items, as well as the risk management objective for entering into the derivative contract. To be designated as a cash flow hedge transaction, the relationship between the derivative and the hedged items must be highly effective in achieving the offset of changes in cash flows attributable to the risk both at the inception of the derivative and on an ongoing basis. Brigham measures hedge effectiveness on a quarterly basis and hedge accounting is discontinued prospectively if it is determined that the derivative is no longer effective in offsetting changes in the cash flows of the hedged item. Gains and losses deferred in accumulated other comprehensive income related to cash flow hedge derivatives that become ineffective remain unchanged until the related production is delivered. If Brigham determines that it is probable that a hedged forecasted transaction will not occur, deferred gains or losses on the derivative are recognized in earnings immediately. See Note 10 for a description of the derivative contracts which Brigham executes.

Other Comprehensive Income (Loss)

Brigham follows the provisions of Statement of Financial Accounting Standards No. 130, "Reporting Comprehensive Income," which establishes standards for reporting comprehensive income. In addition to net income, comprehensive income includes all changes in equity during a period, except those resulting from investments and distributions to stockholders of Brigham.

The components of other comprehensive income (loss) for the years ended December 31, 2005, 2004 and 2003 follow (in thousands):

	2005	2004	2003
Balance, beginning of year	$ (503)	$(1,040)	$(3,047)
Current period settlements reclassified to earnings	4,174	4,694	6,692
Current period change in fair value of hedges	(4,777)	(3,209)	(5,701)
Tax benefits (provisions) related to cash flow hedges	(43)	(290)	561
Net (gains) losses included in earnings	723	(658)	455
Balance, end of year	$ (426)	$ (503)	$(1,040)

Stock Based Compensation

Brigham accounts for employee stock-based compensation using the intrinsic value method prescribed by Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees". Accordingly, Brigham has adopted the disclosure-only provisions of Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation" (SFAS 123).

Under SFAS 123, the fair value of each stock option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions used for grants during the years ended December 31, 2005, 2004 and 2003:

	2005	2004	2003
Risk-free interest rate	4.3%	3.7%	3.7%
Expected life (in years)	4.2	3.9	5.0
Expected volatility	43%	43%	48%
Expected dividend yield	—	—	—
Weighted average fair value per share of stock compensation	$4.78	$3.31	$2.98

The Black-Scholes option pricing model was developed for use in estimating the fair value of traded options that have no vesting restrictions and are transferable. Additionally, the assumptions required by the valuation model are highly subjective. Because Brigham's stock options have significantly different characteristics from those of traded options, and because changes in the subjective input assumptions can materially affect the fair value estimate, in management's opinion the model does not necessarily provide a reliable single measure of the fair value of Brigham's stock options.

Had compensation cost for Brigham's stock options been determined based on the fair market value at the grant dates of the awards consistent with the methodology prescribed by SFAS 123 as amended by SFAS 148, Brigham's net income (loss) and net income (loss) per share for the years ended December 31, 2005, 2004 and 2003 would have been the pro forma amounts indicated below:

	Year Ended December 31,		
	2005	2004	2003
Net income (loss) available to common stockholders (in thousands):			
As reported	$27,435	$19,650	$14,582
Add back: Stock compensation expense previously included in net income	462	434	282
Effect of total employee stock-based compensation expense, determined under fair value method for all awards	(1,330)	(3,189)	(528)
Pro forma	$26,567	$16,895	$14,336
Basic:			
As reported	$ 0.65	$ 0.49	$ 0.63
Pro forma	0.63	0.42	0.62
Diluted:			
As reported	$ 0.63	$ 0.47	$ 0.52
Pro forma	0.61	0.41	0.52

Income Taxes

Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to the differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using the tax rate in effect for the year in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rates of deferred tax assets and liabilities is recognized in income in the year of the enacted rate change. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

Deferred Loan Fees

Deferred loan fees incurred in connection with the issuance of debt are recorded on the balance sheet in other noncurrent assets. The debt issue costs are amortized to interest expense over the life of the debt using the straight-line method. The results obtained using the straight-line method are not materially different than those that would result from using the effective interest method.

Segment Information

All of Brigham's oil and natural gas properties and related operations are located onshore in the United States and management has determined that Brigham has one reportable segment.

Treasury Stock

Treasury stock purchases are recorded at cost. Upon reissuance, the cost of treasury shares held is reduced by the average purchase price per share of the aggregate treasury shares held.

Asset Retirement Obligations

In June 2001, the FASB issued Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (SFAS 143). SFAS 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. Brigham adopted this standard as required on January 1, 2003.

Mandatorily Redeemable Preferred Stock

In May 2003, the FASB issued Statement of Financial Accounting Standards No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity" (SFAS 150). SFAS 150 requires an issuer to classify certain financial instruments within its scope, such as mandatorily redeemable preferred stock, as liabilities (or assets in some circumstances). SFAS 150 defines a financial instrument as mandatorily redeemable if it embodies an unconditional obligation requiring the issuer to redeem the instrument by transferring its assets at a specified or determinable date(s) or upon an event certain to occur. Brigham adopted this standard as required on July 1, 2003.

New Pronouncements

In December 2004, the FASB issued SFAS No. 123R, "Share-Based Payment". SFAS No. 123R is a revision of SFAS No. 123, "Accounting for Stock Based Compensation", and supersedes APB 25. Among other items, SFAS 123R eliminates the use of APB 25 and the intrinsic value method of accounting, and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments, based on the grant date fair value of those awards, in the financial statements. Pro forma disclosure is no longer an alternative under the new standard. Although early adoption is allowed, Brigham will adopt SFAS 123R as of the required effective date for calendar year companies, which is January 1, 2006, using the modified prospective method.

SFAS 123R permits companies to adopt its requirements using either a "modified prospective" method, or a "modified retrospective" method. Under the "modified prospective" method, compensation cost is recognized in the financial statements beginning with the effective date, based on the requirements of SFAS 123R for all share-based payments granted after that date, and based on the requirements of SFAS 123 for all unvested awards granted prior to the effective date of SFAS 123R. Under the "modified retrospective" method, the requirements are the same as under the "modified prospective" method, but also permit entities to restate financial statements of previous periods based on pro forma disclosures made in accordance with SFAS 123.

Brigham currently utilizes the Black-Scholes option pricing model to measure the fair value of stock options granted to employees and directors. While SFAS 123R permits entities to continue to use such a model, the standard also permits the use of a more complex binomial, or "lattice" model. Based upon the type and number of stock options expected to be issued in the future, Brigham has determined that it will continue to use the Black-Scholes model for option valuation as of the current time.

SFAS 123R includes several modifications to the way that income taxes are recorded in the financial statements. The expense for certain types of option grants is only deductible for tax purposes at the time that the taxable event takes place, which could cause variability in Brigham's effective tax rates recorded throughout the year. SFAS 123R does not allow companies to "predict" when these taxable events will take place. Furthermore, it requires that the benefits associated with the tax deductions in excess of recognized compensation cost be reported as a financing cash flow. These future amounts cannot be estimated, because they depend on, among other things, when the stock options are exercised.

Subject to a complete review of the requirements of SFAS 123R, based on stock options granted through December 31, 2005, Brigham expects that the adoption of SFAS 123R on January 1, 2006, will reduce first quarter net earnings by approximately $212,000 ($0.005 per share, diluted). See Note 13 for further information on Brigham's stock-based compensation plans.

In March 2005, the FASB issued FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47), which clarifies the impact that uncertainty surrounding the timing or method of settling an obligation should have on accounting for that obligation under SFAS 143. As the term is used in SFAS 143, a contingent asset retirement obligation refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. For example, a company may have an obligation to retire an offshore facility, where neither the life of the facility nor the method of retirement is known. Brigham does not currently have any assets with a contingent asset retirement obligation. Accordingly, this interpretation has not had any impact on Brigham's financial statements. FIN 47 is effective no later than the end of the fiscal year ending after December 15, 2005, or December 31, 2005 for calendar year companies.

In May 2005, the FASB issued Statement of Financial Accounting Standards No. 154, "Accounting Changes and Error Corrections — a replacement of APB Opinion No. 20 and FASB Statement No. 3" (SFAS 154). SFAS 154 establishes retrospective application as the required method for reporting a change in accounting principle, unless it is impracticable in which the changes should be applied to the latest practicable date presented for voluntary accounting changes and in the absence of specific guidance provided for in a new pronouncement issued by an authoritative body. SFAS 154 also requires that a correction of an error be reported as a prior period adjustment by restating prior period financial statements. SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005.

In February 2006, the FASB issued Statement of Financial Accounting Standards No. 155, "Accounting for Certain Hybrid Instruments — an amendment of FASB Statements No. 133 and 140" (SFAS 155). SFAS 155 amends SFAS 133 to permit fair value measurement for certain hybrid financial instruments that contain an embedded derivative, provides additional guidance on the applicability of SFAS 133 and SFAS 140 to certain financial instruments and subordinated concentrations of credit risk. SFAS 155 is effective for the first fiscal year that begins after September 15, 2006 (January 1, 2007 for Brigham). Brigham is currently evaluating the impact SFAS 155 will have on its consolidated financial statements.

2. Property and Equipment

Property and equipment, at cost, are summarized as follows (in thousands):

	December 31,	
	2005	2004
Oil and natural gas properties	$ 521,808	$ 403,190
Accumulated depletion	(174,479)	(141,211)
	347,329	261,979
Other property and equipment:		
3-D seismic interpretation workstations and software	1,673	2,725
Office furniture and equipment	2,714	2,784
Accumulated depreciation	(3,360)	(4,300)
	1,027	1,209
	$ 348,356	$ 263,188

Brigham capitalizes certain payroll and other internal costs directly attributable to acquisition, exploration and development activities as part of its investment in oil and natural gas properties over the periods benefited by these activities. Capitalized costs do not include any costs related to production, general corporate overhead, or similar activities. Capitalized costs are summarized as follows for the years ended December 31, 2005, 2004 and 2003 (in thousands):

	Year Ended December 31,		
	2005	2004	2003
Capitalized certain payroll and other internal costs	$4,847	$4,872	$4,621
Capitalized interest costs	1,604	1,195	818
	$6,451	$6,067	$5,439

3. Senior Credit Facility and Senior Subordinated Notes

	December 31,	
	2005	2004
	(In thousands)	
Senior Credit Facility	$33,100	$21,000
Senior Subordinated Notes	30,000	20,000
Total Debt	$63,100	$41,000
Less: Current Maturities	—	—
Total Long-Term Debt	$63,100	$41,000

Senior Credit Facility

During June 2005, Brigham amended and restated its senior credit facility to provide for revolving credit borrowings up to a maximum principal amount of $200 million at any one time outstanding. Borrowings under Brigham's senior credit facility cannot exceed its borrowing base, which is determined at least semiannually. Brigham's borrowing base under the amended and restated senior credit facility increased from $80 million to $90 million in November 2005. As of December 31, 2005, Brigham had $33.1 million in borrowings outstanding under its senior credit facility.

Brigham also extended the maturity of its senior credit facility from March 2009 to June 2010 and changed the interest rate that it pays on borrowings under the facility. Borrowings under the senior credit facility bear interest, at Brigham's election, at a base rate (as the term is defined in the senior credit facility) or Eurodollar rate (4.4% at December 31, 2005), plus in each case an applicable margin that is reset quarterly (1.5% at December 31, 2005 and subsequently reset to 1.25% as of January 1, 2006). The applicable interest rate margin varies from 0.0% to 0.5% in the case of borrowings based on the base rate (as the term is defined in the senior credit facility) and from 1.25% to 2.0% in the case of borrowings based on the Eurodollar rate, depending on percentage of the available borrowing base utilized. In addition, Brigham is required to pay a commitment fee on the unused portion of its borrowing base. The applicable commitment fee varies from 0.25% to 0.375%, depending on the percentage of the available borrowing base not utilized. Borrowings under the senior credit facility are collateralized by substantially all of Brigham's oil and natural gas properties under first liens.

The senior credit facility contains various covenants, including among others restrictions on liens, restrictions on incurring other indebtedness, restrictions on mergers, restrictions on investments, and restrictions on hedging activity of a speculative nature or with counterparties having credit ratings below specified levels. The senior credit facility requires Brigham to maintain a current ratio (as defined) of at least 1 to 1 and an interest coverage ratio (as defined) of at least 3 to 1.

Senior Subordinated Notes

During June 2005, Brigham amended its $20 million subordinated credit agreement to provide up to $40 million of borrowings and extended the maturity of the notes from March 2009 until June 2010. As of December 31, 2005, Brigham had $30 million of senior subordinated notes outstanding. The senior subordinated notes are secured obligations ranking junior to Brigham's senior credit facility. Brigham will have the opportunity to draw the additional $10 million available under the subordinated credit agreement until December 29, 2006. Borrowings under the senior subordinated notes are collateralized by substantially all of Brigham's oil and natural gas properties under second liens.

Borrowings under the subordinated credit agreement bear interest based on the Eurodollar rate plus a margin as defined (4.0% and 3.9%, respectively, at December 31, 2005).

Brigham has an interest rate swap that converts $20 million of the borrowings under its subordinated credit agreement from floating to fixed rate debt. At December 31, 2005 this interest rate was 7.6%. This interest rate could increase if Brigham borrows additional debt under its subordinated credit agreement and borrowings under its senior credit agreement reach or exceed 75% of Brigham's available borrowing base. In addition, a commitment fee of 0.750% is payable on the undrawn capacity under the subordinated credit agreement.

4. Preferred Stock

Series A Mandatorily Redeemable Preferred Stock

The following table reflects the outstanding shares of Series A mandatorily redeemable preferred stock and the activity related thereto for the years ended December 31, 2005 and 2004 (in thousands, except share amounts):

	Year Ended December 31, 2005		Year Ended December 31, 2004	
	Shares	Amounts	Shares	Amounts
Balance, beginning of year	475,986	$ 9,520	439,722	$8,794
Dividends paid in kind	29,065	581	36,264	726
Balance, end of year	505,051	$10,101	475,986	$9,520

Brigham has designated 2,250,000 shares of preferred stock as Series A Preferred Stock. The Series A Preferred Stock has a par value of $0.01 per share and a stated value of $20 per share. The Series A Preferred Stock is cumulative and pays dividends quarterly at a rate of 6% per annum of the stated value if paid in cash or 8% per annum of the stated value if paid in kind (PIK) through the issuance of additional Series A Preferred Stock in lieu of cash. From issuance, through September 30, 2005, Brigham paid the dividends on the Series A preferred stock in kind through the issuance of additional shares of preferred stock at a rate of 8% per annum. Beginning on October 1, 2005, Brigham paid all dividend obligations related to the Series A preferred stock in cash at a rate of 6% per annum. The Series A Preferred Stock matures on October 31, 2010 and is redeemable at Brigham's option at 100% or 101% of stated value (depending upon certain conditions) at anytime prior to maturity. The Series A Preferred Stock does not generally have any voting rights, except for certain approval rights and as required by law.

5. Issuance of Common Stock

In February 2006, Brigham filed a universal shelf registration statement that, when and if declared effective by the Securities and Exchange Commission, will allow Brigham to issue common stock, preferred stock, depositary shares, warrants, senior debt and subordinated debt up to an aggregate amount of $300 million.

In November 2005, Brigham issued 2,500,000 shares of Brigham common stock under an existing universal shelf registration statement and received proceeds of approximately $28.2 million, net of underwriting commissions and other offering expenses.

During July and August 2004, Brigham completed the sale of 2,598,500 shares of its common stock under an existing universal shelf registration statement. Net proceeds from the stock sale were approximately $22.1 million.

In December 2003, Brigham issued 2,105,263 shares of Brigham common stock pursuant to the exercise of the Series A — Tranche 2 warrants and 2,298,850 shares of Brigham common stock pursuant to the exercise of the Series B warrants to CSFB Private Equity.

In November 2003, Brigham issued 6,666,667 shares of Brigham common stock pursuant to the exercise of the Series A — Tranche 1 warrants to CSFB Private Equity.

In September 2003, Brigham issued 7,384,090 shares of Brigham common stock in a public offering and received proceeds of approximately $40 million, net of underwriting commissions and other offering expenses.

In June 2003, Brigham issued 206,982 and 408,928 shares of Brigham common stock pursuant to the exercise under a cashless feature of 338,462 and 661,538 warrants, respectively.

In February 2003, 487,805 warrants were exercised under a cashless feature resulting in the issuance of 248,028 shares of Brigham common stock.

6. Asset Retirement Obligations

As referred to in Note 1, Brigham adopted the provisions of SFAS 143 on January 1, 2003. Brigham has asset retirement obligations associated with the future plugging and abandonment of proved properties and related facilities. Prior to the adoption of SFAS 143, Brigham assumed salvage value approximated plugging and abandonment costs. As such, estimated salvage value was not excluded from depletion and plugging and abandonment costs were not accrued for over the life of the oil and gas properties.

The adoption of SFAS 143 resulted in a January 1, 2003 cumulative effect adjustment to record (i) a $1.4 million increase in the carrying values of proved properties, (ii) a $0.8 million decrease in accumulated depletion of oil and natural gas properties and (iii) a $1.9 million increase in other noncurrent liabilities. The net impact of items (i) through (iii) was to record a gain of $0.3 million, net of taxes, as a cumulative effect adjustment of a change in accounting principle in Brigham's consolidated statements of operations upon adoption on January 1, 2003.

Brigham has no assets that are legally restricted for purposes of settling asset retirement obligations. The following table summarizes Brigham's asset retirement obligation transactions recorded in accordance with the provisions of SFAS 143 during the years ended December 31, 2005 and 2004 (in thousands):

	Year Ended December 31,	
	2005	2004
Beginning asset retirement obligations	$2,896	$2,320
Liabilities incurred for new wells placed on production	469	512
Liabilities settled	(10)	(95)
Revisions to estimates	855	—
Accretion of discount on asset retirement obligations	180	159
	$4,390	$2,896

7. Income Taxes

The income tax expense (benefit) consists of the following (in thousands):

	Year Ended December 31,		
	2005	2004	2003
Current income taxes:			
Federal	$ —	$ —	$ —
State	—	—	—
Deferred income taxes:			
Federal	15,037	10,863	(1,223)
State	—	—	—
	$15,037	$10,863	$(1,223)

The differences in income taxes provided and the amounts determined by applying the federal statutory tax rate to income before income taxes result from the following (in thousands):

	Year Ended December 31,		
	2005	2004	2003
Tax at statutory rate	$14,865	$10,679	$ 5,789
Add the effect of:			
Nondeductible expenses	—	5	5
Deductible stock compensation	(91)	(194)	(118)
Preferred stock dividends	257	373	—
Valuation allowance	—	—	(7,554)
Unrealized hedging losses	—	—	561
Other	6	—	94
	$15,037	$10,863	$(1,223)

The components of deferred income tax assets and liabilities are as follows (in thousands):

	December 31,	
	2005	2004
Deferred tax assets		
Current:		
Unrealized hedging losses	$ 229	$ 271
Derivative assets	268	11
Current	497	282
Non-current:		
Net operating loss carryforwards	39,393	36,743
Capital loss carryforwards	61	634
Stock compensation	942	816
Asset retirement obligations	1,536	1,014
Other	196	31
Non-current	42,128	39,238
	42,625	39,520

	December 31, 2005	December 31, 2004
Deferred tax liabilities		
Current:		
Derivative liabilities	$ —	$ (28)
Gas imbalances	(15)	(15)
Current	(15)	(43)
Non-current:		
Depreciable and depletable property	(65,630)	(47,635)
	(65,645)	(47,678)
Net deferred tax asset (liability)	(23,020)	(8,158)
Valuation allowance	(61)	(634)
Total deferred tax asset (liability)	$(23,081)	$ (8,792)
Reflected in the accompanying balance sheets as:		
Current deferred income tax asset	$ 482	$ 239
Non-current deferred income tax liability	(23,563)	(9,031)
	$(23,081)	$ (8,792)

Realization of deferred tax assets associated with (i) net operating loss carryforwards ("NOLs") and (ii) existing temporary differences between book and taxable income is dependent upon generating sufficient taxable income within the carryforward period available under tax law. In 2003, management determined that it was more likely than not that capital loss carryforwards of approximately $1.8 million would expire unused and, accordingly, established a valuation allowance of $634,000. Capital loss carryforwards of approximately $1.6 million expired at the end of 2005 and, therefore, the deferred tax asset as well as the corresponding valuation allowance were reduced by $573,000 to $61,000.

In addition, at December 31, 2005, Brigham has capital loss carryforwards of approximately $175,000 that expire in 2007 on which Brigham established a valuation allowance as discussed above.

Brigham believes an Internal Revenue Code Sec. 382 ownership change may have occurred in March 2001 and in November 2005, as a result of a potential 50% change in ownership among its 5% shareholders over a three-year period. The limitations resulting from the March 2001 and November 2005 ownership changes approximate $5.2 million annually and $23 million annually, respectively, which can be increased by recognized Built-in-Gains over five years following the ownership change. Management believes that the limitations will not have a material impact on the utilization of its NOL's because the maximum limitations to be utilized exceed total NOL's affected by the limitations.

8. Net Income (Loss) Per Share

Basic earnings per share are computed by dividing net income (loss) available to common stockholders by the weighted average number of common shares outstanding for the period. The computation of diluted net income (loss) per share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock or resulted in the issuance of common stock that would then share in the earnings of Brigham.

	Year Ended December 31,		
	2005	2004	2003
	(In thousands, except per share amounts)		
Basic EPS:			
Income (loss) available to common stockholders before cumulative change in accounting principle	$27,435	$19,650	$14,314
Cumulative change in accounting principle	—	—	268
Income (loss) available to common stockholders	$27,435	$19,650	$14,582
Weighted average common shares outstanding — basic	42,481	40,445	23,363
Basic EPS:			
Income (loss) available to common stockholders before cumulative change in accounting principle	$ 0.65	$ 0.49	$ 0.62
Cumulative change in accounting principle	—	—	0.01
Income (loss) available to common stockholders	$ 0.65	$ 0.49	$ 0.63

	Year Ended December 31,		
	2005	2004	2003
Diluted EPS:			
Income (loss) available to common stockholders before cumulative change in accounting principle	$27,435	$19,650	$14,314
Cumulative change in accounting principle	—	—	268
Income (loss) available to common stockholders	27,435	19,650	14,582
Adjustments for assumed conversions:			
Dividends and accretion on mandatorily redeemable preferred stock(1)	—	—	3,290
	27,435	19,650	3,290
Income (loss) available to common stockholders before cumulative change in accounting principle — diluted	27,435	19,650	17,604
Cumulative change in accounting principle	—	—	268
Income (loss) available to common stockholders — diluted	$27,435	$19,650	$17,872
Common shares outstanding	42,481	40,445	23,363
Effect of dilutive securities:			
Warrants	—	—	317
Mandatorily redeemable preferred stock	—	—	9,971
Stock options and restricted stock	1,247	1,171	703
Potentially dilutive common shares	1,247	1,171	10,991
Adjusted common shares outstanding — diluted	43,728	41,616	34,354
Diluted EPS:			
Income (loss) available to common stockholders before cumulative change in accounting principle	$ 0.63	$ 0.47	$ 0.51
Cumulative change in accounting principle	—	—	0.01
Income (loss) available to common stockholders	$ 0.63	$ 0.47	$ 0.52

(1) The amount of dividends included in dividends and accretion on mandatorily redeemable preferred stock includes only the dividends paid in kind on the $40 million of mandatorily redeemable preferred stock (2.0 million shares) that were issued with warrants whose exercise price is payable in either cash or in shares of mandatorily redeemable preferred stock.

At December 31, 2005, 2004, and 2003, potential dilution of approximately 330,000, 718,500, and, 1,000,000 shares of common stock, respectively, related to mandatorily redeemable preferred stock, convertible debt, warrants and options were outstanding, but were not included in the computation of diluted income (loss) per share because the effect of these instruments would have been anti-dilutive.

9. Contingencies, Commitments and Factors Which May Affect Future Operations

Litigation

Brigham is, from time to time, party to certain lawsuits and claims arising in the ordinary course of business. While the outcome of lawsuits and claims cannot be predicted with certainty, management does not expect these matters to have a materially adverse effect on the financial condition, results of operations or cash flows of Brigham.

As of December 31, 2005, there are no known environmental or other regulatory matters related to Brigham's operations that are reasonably expected to result in a material liability to Brigham. Compliance with environmental laws and regulations has not had, and is not expected to have, a material adverse effect on Brigham's financial position, results of operations or cash flows.

Operating Lease Commitments

Brigham leases office equipment and space under operating leases expiring at various dates. The noncancelable term of the lease for Brigham's office space expires in 2012. The future minimum annual rental payments under the noncancelable terms of these leases at December 31, 2005 are as follows (in thousands):

2006	$ 709
2007	698
2008	687
2009	703
2010	720
Thereafter	1,117
	$4,634

Future minimum rental payments are not reduced by sublease rental income of approximately $44,000 due in 2006 under noncancelable subleases.

Rental expense for the years ended December 31, 2005, 2004 and 2003 was approximately $596,000, $754,000, and $851,000, respectively.

Major Purchasers

The following purchasers accounted for 10% or more of Brigham's oil and natural gas sales for the years ended December 31, 2005, 2004 and 2003:

	2005	2004	2003
Purchaser A	—	11%	—
Purchaser B	—	12%	13%
Purchaser C	20%	—	—

Brigham believes that the loss of any individual purchaser would not have a long-term material adverse impact on its financial position or results of operations.

Factors Which May Affect Future Operations

Since Brigham's major products are commodities, significant changes in the prices of oil and natural gas could have a significant impact on Brigham's results of operations for any particular year.

10. Derivative Instruments and Hedging Activities

Brigham utilizes various commodity swap and option contracts to (i) reduce the effects of volatility in price changes on the oil and natural gas commodities it produces and sells, (ii) reduce commodity price risk and (iii) provide a base level of cash flow in order to assure it can execute at least a portion of its capital spending plans.

The following table sets forth Brigham's oil and natural gas prices including and excluding the hedging gains and losses and the increase or decrease in oil and natural gas revenues as a result of the hedging activities for the three year period ended December 31, 2005:

	Year Ended December 31,		
	2005	2004	2003
Natural gas			
Average price per Mcf as reported (including hedging results)	$ 7.97	$ 5.84	$ 4.92
Average price per Mcf realized (excluding hedging results)	$ 8.29	$ 6.05	$ 5.68
Decrease in revenue (in thousands)	$2,925	$1,853	$4,807
Oil			
Average price per Bbl as reported (including hedging results)	$51.95	$35.17	$28.17
Average price per Bbl realized (excluding hedging results)	$54.73	$40.13	$30.79
Decrease in revenue (in thousands)	$1,249	$2,841	$1,885

For the years ended December 31, 2005, 2004 and 2003, ineffectiveness associated with Brigham's derivative contracts designated as cash flow hedges increased (decreased) earnings by approximately $(0.7) million, $0.7 million, and $(0.7) million, respectively. These amounts are included in other income and expense.

Natural Gas and Crude Oil Derivative Contracts

Cash flow hedges

Brigham's cash flow hedges consisted of costless collars (purchased put options and written call options). The costless collars are used to establish floor and ceiling prices on anticipated future oil and natural gas production. There were no net premiums paid or received when Brigham entered into these option agreements.

Derivative positions included written put options that are not designated as cash flow hedges and are reflected at fair value on the balance sheet. These positions were entered into in conjunction with a costless collar to offset the cost of other option positions that are designated as hedges. At each balance sheet date, the value of derivative contracts not designated as cash flow hedges is adjusted to reflect current fair value and any gains or losses are recognized as other income (expense). The following table provides a summary of the fair value of these derivatives included in other current liabilities (in thousands):

	December 31,	
	2005	2004
Fair value of undesignated derivatives	$(125)	$ (33)

The following table provides a summary of the impact on earnings from non-cash gains (losses) included in other income (expense) related to changes in the fair values of these derivative contracts for the three years ended December 31 (in thousands):

	Year Ended December 31,		
	2005	2004	2003
Increase (decrease) in earnings due to changes in fair value of undesignated derivatives	$(92)	$(33)	$ —

The following table reflects our open commodity derivative contracts at December 31, 2005, the associated volumes and the corresponding weighted average NYMEX reference price.

Settlement Period	Derivative Instrument	Hedge Strategy	Notional Amount Gas (MMBTU)	Notional Amount Oil (Barrels)	Nymex Reference Price
Costless Collars					
01/01/06 - 03/31/06	Purchased put	Cash flow		7,500	$62.00
	Written call	Cash flow		7,500	74.50
04/01/06 - 10/31/06	Purchased put	Cash flow	490,000		$ 8.00
	Written call	Cash flow	490,000		14.85
04/01/06 - 06/30/06	Purchased put	Cash flow		16,500	$54.80
	Written call	Cash flow		16,500	75.00
04/01/06 - 7/31/06	Purchased put	Cash flow	360,000		$ 8.00
	Written call	Cash flow	360,000		15.60
04/01/06 - 7/31/06	Purchased put	Cash flow	360,000		$ 8.00
	Written call	Cash flow	360,000		17.00
04/01/06 - 09/30/06	Purchased put	Cash flow		42,000	$50.00
	Written call	Cash flow		42,000	75.60
11/01/06 - 03/31/07	Purchased put	Cash flow	450,000		$ 8.00
	Written call	Cash flow	450,000		21.20
08/01/06 - 10/31/06	Purchased put	Cash flow	360,000		$ 8.00
	Written call	Cash flow	360,000		16.65
10/01/06 - 12/31/06	Purchased put	Cash flow		27,000	$50.00
	Written call	Cash flow		27,000	77.50
11/01/06 - 01/31/07	Purchased put	Cash flow	540,000		$ 8.00
	Written call	Cash flow	540,000		23.25
01/01/07 - 03/31/07	Purchased put	Cash flow		24,000	$50.00
	Written call	Cash flow		24,000	78.25
Three Way Costless Collars					
01/01/06 - 3/31/06	Purchased put	Cash flow	150,000		$ 6.75
	Written call	Cash flow	150,000		8.80
	Written put	Undesignated	150,000		5.50
01/01/06 - 3/31/06	Purchased put	Cash flow	210,000		$ 8.00
	Written call	Cash flow	210,000		9.75
	Written put	Undesignated	210,000		6.50
01/01/06 - 3/31/06	Purchased put	Cash flow	240,000		$10.00
	Written call	Cash flow	240,000		13.08
	Written put	Undesignated	240,000		8.50
01/01/06 - 3/31/06	Purchased put	Cash flow		18,000	$48.00
	Written call	Cash flow		18,000	60.70
	Written put	Undesignated		18,000	38.00
04/01/06 - 10/31/06	Purchased put	Cash flow	420,000		$ 7.50
	Written call	Cash flow	420,000		9.15
	Written put	Undesignated	420,000		6.25

Settlement Period	Derivative Instrument	Hedge Strategy	Notional Amount Gas (MMBTU)	Notional Amount Oil (Barrels)	Nymex Reference Price
04/01/06 - 10/31/06	Purchased put	Cash flow	490,000		$ 8.50
	Written call	Cash flow	490,000		9.96
	Written put	Undesignated	490,000		7.00
04/01/06 - 6/30/06	Purchased put	Cash flow		7,500	$63.00
	Written call	Cash flow		7,500	75.25
	Written put	Undesignated		7,500	48.00
07/01/06 - 9/30/06	Purchased put	Cash flow		15,000	$63.00
	Written call	Cash flow		15,000	75.65
	Written put	Undesignated		15,000	48.00

Interest rate swap

Periodically, Brigham may use interest rate swap contracts to adjust the proportion of its total debt that is subject to variable interest rates to fixed rates. Under such an interest rate swap contract, Brigham agrees to pay an amount equal to a specified fixed-rate of interest for a certain notional amount and receive in return an amount equal to a variable-rate. The notional amounts of the contract are not exchanged. No other cash payments are made unless the contract is terminated prior to maturity. Although no collateral is held or exchanged for the contract, the interest rate swap contract is entered into with a major financial institution with an investment grade credit rating in order to minimize Brigham's counterparty credit risk. The interest rate swap contract is designated as cash flow hedges against changes in the amount of future cash flows associated with Brigham's interest payments on variable-rate debt. The effect of this accounting on operating results is that interest expense on a portion of variable-rate debt being hedged is recorded based on fixed interest rates.

At December 31, 2005, Brigham had an interest rate swap contract to pay a fixed-rate of interest of 7.6% on $20 million notional amount of senior subordinated notes. The $20 million notional amount of the outstanding contract matures in March 2009. As of December 31, 2005 and 2004, approximately $641,000 and $(1,000) of unrealized gains (losses) are included in accumulated other comprehensive income (loss) on the balance sheet which represents the fair values of the interest rate swap agreement as of that date. The fair value of the interest rate swap contract is based on quoted market prices and third-party provided calculations, which reflect the present values of the difference between estimated future variable-rate receipts and future fixed-rate payments.

Fair values

The fair value of derivative contracts designated as cash flow hedges is reflected on the balance sheet as detailed in the following schedule (in thousands). The current asset and liability amounts represent the fair values expected to be included in the results of operations for the subsequent year.

	December 31, 2005	December 31, 2004
Other current liabilities	$(2,112)	$(870)
Other noncurrent liabilities	(61)	(1)
Other current assets	224	142
Other noncurrent assets	654	3
Net fair value of derivative contracts	$(1,295)	$(726)

11. Financial Instruments

Brigham's non-derivative financial instruments include cash and cash equivalents, accounts receivable, accounts payable and long-term debt. The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximate fair value because of their immediate or short-term maturities. The carrying value of Brigham's senior credit facility approximates its fair market value since it bears interest at floating market interest rates. The fair value of Brigham's senior subordinated notes at December 31, 2005 and 2004 was $29.4 million and $20 million, respectively. The fair value of the Series A mandatorily redeemable preferred stock at December 31, 2005 and 2004 was approximately $8.9 million and $9.5 million, respectively.

Brigham's accounts receivable relate to oil and natural gas sold to various industry companies, and amounts due from industry participants for expenditures made by Brigham on their behalf. Credit terms, typical of industry standards, are of a short-term nature and Brigham does not require collateral. Brigham's accounts receivable at December 31, 2005 and 2004 do not represent significant credit risks as they are dispersed across many counterparties. Counterparties to Brigham's oil and natural gas financial hedges are investment grade financial institutions.

12. Employee Benefit Plans

Brigham has adopted a defined contribution 401(k) plan for substantially all of its employees. The plan provides for Brigham matching of employee contributions to the plan, at Brigham's discretion. During 2005, 2004 and 2003, Brigham provided a base match equal to 25% of eligible employee contributions. Based on attainment of performance goals established at the beginning of each fiscal year, Brigham matched an additional 41%, 25.25%, and 47% of eligible employee contributions made during 2005, 2004 and 2003, respectively. Brigham contributed approximately $303,000, $204,000, and $250,000 to the 401(k) plan for the years ended December 31, 2005, 2004 and 2003, respectively, to match eligible contributions by employees.

13. Stock Based Compensation

Brigham provides an incentive plan for the issuance of stock options, stock appreciation rights, stock, restricted stock, cash or any combination of the foregoing. The objective of this plan is to provide incentive and reward key employees whose performance may have a significant impact on the success of Brigham. As amended by stockholder resolution in May 2003, the number of shares available under the plan is equal to the lesser of 4,387,500 or 15% of the total number of shares of common stock outstanding. The Compensation Committee of the Board of Directors determines the type of awards made to each participant and the terms, conditions and limitations applicable to each award. At December 31, 2002, Brigham had issued approximately 85,000 incentive awards in excess of the amount then currently authorized by the plan. Brigham stockholders approved an increase in the total shares available for incentive awards as noted above in May 2003. As a result, the grant date for the 85,000 options is considered May 2003 for accounting purposes. The exercise price for these options was originally set at the market value of Brigham's common stock, however as of May 2003, it was less than the fair market value of Brigham's common stock at that date. Accordingly, Brigham recognized approximately $156,000 of unearned stock compensation and is amortizing this amount to compensation expense over the vesting period of the options. With the exception of these 85,000 options, options granted subsequent to March 4, 1997 have an exercise price equal to the fair market value of Brigham's common stock on the date of grant and vest over five years.

Brigham also maintains a director stock option plan under which stock options are awarded to non-employee directors. In May 2003, the plan was amended by stockholder resolution to increase the number of shares available for issuance to 430,000 shares of common stock. Options granted under this plan have an exercise price equal to the fair market value of Brigham common stock on the date of grant and vest over five years.

The following table summarizes option activity under the incentive plans for each of the three years ended December 31, 2005:

	2005		2004		2003	
	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
Options outstanding at beginning of year	2,977,600	$ 6.01	2,582,675	$ 4.78	1,788,135	$ 3.00
Granted	350,000	$12.13	790,000	$ 8.75	1,127,500	$ 6.46
Forfeited or cancelled	(40,800)	$ 6.92	(80,894)	$(4.72)	(23,200)	$(3.49)
Exercised	(340,467)	$ 3.88	(314,181)	$(3.06)	(309,760)	$(2.68)
Options outstanding at end of year	2,946,333	$ 6.96	2,977,600	$ 6.01	2,582,675	$ 4.78
Options exercisable at end of year	1,085,133	$ 5.31	792,557	$ 4.30	656,633	$ 3.14

Brigham is required to use variable accounting for 252,500 of the stock options granted during 2000 of which 100,000 remain outstanding at December 31, 2005. This method of accounting requires recognition of noncash compensation expense for the difference between the option exercise price and the market price of Brigham's stock at the end of the accounting period of vested options.

The following table summarizes information about stock options outstanding at December 31, 2005:

	Options Outstanding			Options Exercisable	
Exercise Price	Number Outstanding at December 31, 2005	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable at December 31, 2005	Weighted-Average Exercise Price
$1.55 to $1.83	101,000	0.1 years	$ 1.83	101,000	$1.83
2.38 to 3.41	268,033	3.0 years	$ 3.33	154,333	$3.32
3.66 to 5.08	540,400	3.1 years	$ 4.21	328,300	$4.17
6.46 to 6.73	879,000	4.8 years	$ 6.68	330,000	$6.69
7.88 to 8.89	747,900	5.6 years	$ 8.72	157,500	$8.67
8.93 to 12.31	410,000	6.0 years	$11.59	14,000	$8.97
$1.55 to $12.31	2,946,333	3.7 years	$ 6.96	1,085,133	$5.31

Restricted Stock

During the years ended December 31, 2005 and 2004, Brigham issued 137,650 and 70,000, respectively, restricted shares of common stock as compensation to officers and employees of Brigham. The restricted shares vest over five years or cliff-vest at the end of five years. Brigham recognized approximately $1.4 million and $0.5 million of unearned stock compensation and will amortize this amount to compensation expense over the vesting period of the restricted stock.

The following table reflects the outstanding restricted stock awards and activity related thereto for the years ended December 31:

	Year Ended December 31, 2005		Year Ended December 31, 2004	
	Number of Shares	Weighted-Average Price	Number of Shares	Weighted-Average Price
Restricted Stock Awards:				
Restricted shares outstanding at the beginning of the year	325,000	$ 5.65	350,000	$5.23
Shares granted	137,650	$10.42	70,000	$7.35
Lapse of restrictions	(65,000)	$ 5.23	(72,083)	$5.23
Forfeitures	—	$ —	(22,917)	$5.69
Restricted shares outstanding at the end of the year	397,650	$ 7.22	325,000	$5.65

14. Related Party Transactions

During the years ended December 31, 2005, 2004, and 2003, Brigham incurred costs of approximately $2.3 million, $2.9 million and $2.0 million, respectively, in fees for land acquisition services performed by a company owned by a brother of Brigham's Chairman, President and Chief Executive Officer and its Executive Vice President — Land and Administration. Other participants in Brigham's 3-D seismic projects reimbursed Brigham for a portion of these amounts. At December 31, 2005 and 2004, Brigham had a liability recorded in accounts payable of approximately $25,000 and $236,000, respectively, related to services performed by this company.

Mr. Harold Carter, a director of Brigham, served as a consultant to Brigham on various aspects of its business and strategic issues. Fees paid for these services by Brigham were approximately $30,000 for each the years ended December 31, 2005, 2004, and 2003. Additional payments totaling approximately $12,000 were made during each of the years ended December 31, 2005, 2004, and 2003, for the reimbursement of certain expenses. At December 31, 2005 and 2004, there were no payables related to these services recorded by Brigham.

From time to time, in the normal course of business, Brigham has engaged a drilling company in which Mr. Steven Webster, one of Brigham's current directors, owns stock and serves on the board of directors. Total payments to the drilling company during 2005, 2004 and 2003 were $3.5 million, $3.5 million, and $1.2 million, respectively. Brigham did not owe the drilling company any amounts at December 31, 2005. Brigham owed the drilling company approximately $0.7 million at December 31, 2004. At December 31, 2005 and 2004 Brigham had short-term accounts receivable from Mr. Webster of approximately $1,500 and $2,200, respectively. These receivables represent the director's share of costs related to his working interest ownership in the Staubach #1, Burkhart #1R and Matthes-Huebner #1 wells that are operated by Brigham. Mr. Webster obtained his interest in these wells through an exploration and production company, Carrizo, that is not affiliated with Brigham. Mr. Webster was a co-founder of Carrizo and is currently chairman of Carrizo's board of directors. At December 31, 2005 and 2004, Carrizo owed Brigham $175,000 and $114,000, respectively, for exploration and production activities. Brigham owed Carrizo $20,000 and $0 at December 31, 2005 and 2004, respectively. Mr. Webster is also chairman of the board of directors for a well services company that Brigham made payments totaling approximately $560,000 during 2005. Brigham owed the well services company approximately $43,000 at December 31, 2005.

From time to time, in the normal course of business, Brigham has engaged a service company in which Mr. Hobart Smith, one of Brigham's current directors, owns stock and serves as a consultant. Total payments to the service company during 2005, 2004 and 2003 were $1.2 million, $1 million, and $478,000, respectively. At December 31, 2005 and 2004, Brigham owed the service company approximately $61,000 and $132,000, respectively.

15. Supplemental Cash Flow Information

	Year Ended December 31,		
	2005	2004	2003
Cash paid for interest, net of capitalized amounts	$2,575	$1,634	$ 2,447
Noncash investing and financing activities:			
Dividends and accretion on mandatorily redeemable preferred stock	581	726	3,448
Capitalized asset retirement obligations	1,324	512	1,630
Conversion of preferred stock to common stock via exercise of warrants	—	—	18,534
Accrued drilling costs	6,119	2,183	1,189
Capitalized stock compensation	337	291	229
Issuance of restricted stock	1,435	514	1,831
Forfeitures of restricted stock	—	131	—
Issuance of stock options	—	—	296

16. Other Assets and Liabilities

Other current assets consist of the following (in thousands):

	December 31	
	2005	2004
Prepayments	$ 593	$531
Derivative assets	224	142
Other	226	228
	$1,043	$901

Other current liabilities consist of the following (in thousands):

	December 31	
	2005	2004
Derivative liabilities	$2,236	$ 870
Other accrued liabilities	1,883	1,355
	$4,119	$2,225

BRIGHAM EXPORATION COMPANY

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

Oil and Natural Gas Exploration and Production Activities

Oil and natural gas sales reflect the market prices of net production sold or transferred with appropriate adjustments for royalties, net profits interest and other contractual provisions. Lease operating expenses include lifting costs incurred to operate and maintain productive wells and related equipment including such costs as operating labor, repairs and maintenance, materials, supplies and fuel consumed. Production taxes include production and severance taxes. Depletion of oil and natural gas properties relates to capitalized costs incurred in acquisition, exploration and development activities. Results of operations do not include interest expense and general corporate amounts.

Costs Incurred and Capitalized Costs

The costs incurred in oil and natural gas acquisition, exploration and development activities follow (in thousands):

	December 31,		
	2005	2004	2003
Costs incurred for the year:			
Exploration (including geological and geophysical costs)	$ 54,338	$30,327	$20,243
Property acquisition	15,701	6,226	4,850
Development	48,588	50,872	22,437
	$118,627	$87,425	$47,530

Following is a summary of capitalized costs (in thousands) excluded from depletion at December 31, 2005 by year incurred. Excluded costs for prospects are accumulated by year. Costs are reflected in the full cost pool as the drilling program is executed or as costs are evaluated and deemed impaired. Brigham anticipates these excluded costs will be included in the depletion computation over the next five years. Brigham is unable to predict the future impact on depletion rates.

	December 31,			Prior Years	Total
	2005	2004	2003		
Property acquisition	$ 5,328	$2,256	$1,726	$ 4,521	$13,831
Exploration (including geological and geophysical costs)	4,658	6,344	1,213	10,804	23,019
Capitalized interest	1,198	—	—	—	1,198
Total	$11,184	$8,600	$2,939	$15,325	$38,048

Oil and Natural Gas Reserves and Related Financial Data

Information with respect to Brigham's oil and natural gas producing activities is presented in the following tables. Reserve quantities, as well as certain information regarding future production and discounted cash flows, were determined by Brigham's independent petroleum consultants, Cawley, Gillespie and Associates, Inc.

Oil and Natural Gas Reserve Data

The following tables present Brigham's independent petroleum consultants' estimates of its proved oil and natural gas reserves. Brigham emphasizes reserves are approximates and are expected to change as additional information becomes available. Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment.

	Natural Gas (MMcf)	Oil (MBbls)
Proved reserves at December 31, 2002	99,428	3,607
Revisions of previous estimates	(6,148)	176
Extensions, discoveries and other additions	22,479	1,067
Production	(6,356)	(720)
Proved reserves at December 31, 2003	109,403	4,130
Revisions of previous estimates	(11,142)	(642)
Extensions, discoveries and other additions	12,444	321
Production	(8,830)	(573)
Proved reserves at December 31, 2004	101,875	3,236
Revisions of previous estimates	(595)	(11)
Purchases of reserves in place	4,054	65
Extensions, discoveries and other additions	17,143	486
Production	(9,213)	(450)
Proved reserves at December 31, 2005	113,264	3,326
Proved developed reserves at December 31:		
2002	42,161	2,330
2003	49,920	2,863
2004	47,494	2,124
2005	55,664	2,069

Proved reserves are estimated quantities of natural gas and crude oil, which geological and engineering data indicate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Standardized Measure of Discounted Future Net Cash Inflows and Changes Therein

The following table presents a standardized measure of discounted future net cash inflows (in thousands) relating to proved oil and natural gas reserves. Future cash flows were computed by applying year-end prices of oil and natural gas relating to Brigham's proved reserves to the estimated year-end quantities of those reserves. Future price changes were considered only to the extent provided by contractual agreements in existence at year-end. Future production and development costs were computed by estimating those expenditures expected to occur in developing and producing the proved oil and natural gas reserves at the end of the year, based on year-end costs. Actual future cash inflows may vary considerably, and the standardized measure does not necessarily represent the fair value of Brigham's oil and natural gas reserves. The effects of hedging activities are insignificant to the standardized measure of discounted future net cash flows.

	December 31,		
	2005	2004	2003
Future cash inflows	$1,259,009	$766,344	$737,544
Future production costs	(220,499)	(159,697)	(123,176)
Future development costs	(122,419)	(79,868)	(58,978)
Future income tax expense	(237,268)	(116,254)	(138,118)
Future net cash inflows	678,823	410,525	417,272
10% annual discount for estimated timing of cash flows	(282,482)	(170,816)	(155,674)
Standardized measure of discounted future net cash flows	$ 396,341	$239,709	$261,598

Year-end spot prices were adjusted to reflect applicable transportation and quality differentials on a well-by-well basis to arrive at realized sales prices used to estimate Brigham's reserves. The sales prices for Brigham's reserve estimates were as follows:

	Natural Gas (MMbtu)	Oil (Bbl)
December 31, 2005	$9.44	$61.04
December 31, 2004	6.19	43.46
December 31, 2003	5.83	32.55

Changes in the future net cash inflows discounted at 10% per annum follow (in thousands):

	December 31,		
	2005	2004	2003
Beginning of period	$239,709	$261,598	$239,698
Sales of oil and natural gas produced, net of production costs	(90,480)	(67,127)	(50,559)
Previously estimated development costs incurred during the period	17,524	37,109	14,370
Extensions and discoveries	78,184	27,053	91,383
Net change of prices and production costs	171,764	38,027	20,434
Change in future development costs	(32,838)	(40,086)	(11,281)
Changes in production rates (timing)	32,284	(33,579)	(40,287)
Revisions of previous quantity estimates	(2,871)	(47,327)	(15,063)
Accretion of discount	29,447	34,381	30,737
Change in income taxes	(68,711)	27,452	(14,537)
Purchases of reserves in place	14,221	—	—
Other	8,108	2,208	(3,297)
End of period	$396,341	$239,709	$261,598

BRIGHAM EXPLORATION COMPANY

SUPPLEMENTAL QUARTERLY FINANCIAL INFORMATION

Quarterly Financial Data (Unaudited)

	Year Ended December 31, 2005			
	Quarter 1	Quarter 2	Quarter 3	Quarter 4
Revenue	$16,746	$18,490	$25,226	$36,578
Operating income	5,954	8,003	13,447	19,379
Net income	3,048	4,810	7,678	11,899
Net income per share:				
Basic	$ 0.07	$ 0.11	$ 0.18	$ 0.27
Diluted	$ 0.07	$ 0.11	$ 0.18	$ 0.26

	Year Ended December 31, 2004			
	Quarter 1	Quarter 2	Quarter 3	Quarter 4
Revenue	$16,820	$17,957	$17,267	$20,184
Operating income	7,986	8,809	7,561	8,475
Net income	4,925	5,138	4,491	5,096
Net income per share:				
Basic	$ 0.13	$ 0.13	$ 0.11	$ 0.12
Diluted	$ 0.12	$ 0.13	$ 0.11	$ 0.12

At December 31, 2005, Brigham had regular tax NOLs of approximately $112.6 million available as a deduction against future taxable income. Additionally, Brigham has approximately $98.9 million of alternative minimum tax ("AMT") NOLs. The NOLs expire from 2012 through 2025. The value of these NOLs depends on the ability of Brigham to generate taxable income. A summary of the NOLs follows (in thousands):

	Regular NOLs	AMT NOLs
Expiration Date:		
December 31, 2012	$ 13,311	$ 8,687
December 31, 2018	27,031	23,790
December 31, 2019	20,329	19,719
December 31, 2020	13,559	8,634
December 31, 2021	18,990	18,314
December 31, 2022	5,287	4,949
December 31, 2023	5,047	5,117
December 31, 2024	3,909	4,345
December 31, 2025	5,088	5,331
	$112,551	$98,886

INDEX TO EXHIBITS

Number	Description
3.1	— Certificate of Incorporation (filed as Exhibit 3.1 to Brigham's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
3.2	— Certificates of Amendment to Certificate of Incorporation (filed as Exhibit 3.1.1 to Brigham's Registration Statement on Form S-3 (Registration No. 333-37558), and incorporated herein by reference).
3.3	— Bylaws (filed as Exhibit 3.2 to Brigham's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
4.1	— Form of Common Stock Certificate (filed as Exhibit 4.1 to Brigham's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
4.2	— Certificate of Designations of Series A Preferred Stock (Par Value $.01 Per Share) of Brigham Exploration Company filed October 31, 2000 (filed as Exhibit 4.1 to Brigham's Current Report on Form 8-K, as amended (filed November 8, 2000), and incorporated herein by reference).
4.3	— Certificate of Amendment of Certificate of Designations of Series A Preferred Stock (Par Value $.01 Per Share) of Brigham Exploration Company, filed March 2, 2001 (filed as Exhibit 4.2.1 to Brigham's Annual Report on Form 10-K for the year ended December 31, 2000 (filed March 23, 2001), and incorporated herein by reference).
4.4	— Certificate of Designations of Series B Preferred Stock (Par Value $.01 Per Share) of Brigham Exploration Company filed December 20, 2002 (filed as Exhibit 4.4 to Brigham's Annual Report on Form 10-K for the year ended December 31, 2002 (filed March 31, 2003) and incorporated herein by reference).
4.5	— Certificate of Elimination of Certificate of Designations of Series B Preferred Stock of Brigham Exploration Company, dated June 4, 2004, (filed as Exhibit 99.2 to Brigham's Current Report on Form 8-K (filed July 20, 2004), and incorporated herein by reference).
10.1	— Amended and Restated Agreement of Limited Partnership of Brigham Oil & Gas, L.P., dated December 30, 1997 by and among Brigham, Inc., Brigham Holdings I, L.L.C. and Brigham Holdings II, L.L.C. (filed as Exhibit 10.1.4 to Brigham's Annual Report on Form 10-K for the year ended December 31, 1998, and incorporated herein by reference)
10.2*	— Consulting Agreement dated May 1, 1997, by and between Brigham Oil & Gas, L.P. and Harold D. Carter (filed as Exhibit 10.4 to Brigham's Registration Statement on Form S-1 (Registration No. 33-53873), and incorporated herein by reference).
10.3*	— Letter agreement, dated as of March 20, 2000, setting forth amendments effective January 1, 2000, to the Consulting Agreement, dated May 1, 1997, by and between Brigham Oil & Gas, L.P. and Harold D. Carter (filed as Exhibit 10.5.1 to Brigham's Annual Report on Form 10-K for the year ended December 31, 1999, and incorporated herein by reference).
10.4*	— Letter agreement, setting forth amendments to the Consulting Agreement, dated May 1, 1997, by and between Brigham Oil & Gas, L.P. and Harold D. Carter. (filed as Exhibit 10.4 to Brigham's Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference
10.5*	— Employment Agreement, by and between Brigham Exploration Company and Ben M. Brigham (filed as Exhibit 10.7 to Brigham's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.6*	— 1997 Incentive Plan of Brigham Exploration Company as amended through April 9, 2003 (filed as Appendix B to Brigham's Definitive Proxy Statement on Schedule 14-A on May 7, 2003 and incorporated herein by reference).
10.7*	— Form of Option Agreement for certain executive officers (filed as Exhibit 10.9.1 to Brigham's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.8*	— Form of Restricted Stock Agreement for certain executive officers dated as of October 27, 2000 (filed as Exhibit 10.8.2 to Brigham's Annual Report on Form 10-K for the year ended December 31, 2000 (filed March 23, 2001), and incorporated herein by reference).

Number	Description
10.9	— Two Bridgepoint Lease Agreement dated September 30, 1996, by and between Investors Life Insurance Company of North America and Brigham Oil & Gas, L.P. (filed as Exhibit 10.14 to Brigham's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.10	— First Amendment to Two Bridge Point Lease Agreement dated April 11, 1997 between Investors Life Insurance Company of North America and Brigham Oil & Gas, L.P. (filed as Exhibit 10.9.1 to Brigham's Registration Statement on Form S-1 (Registration No. 333-53873), and incorporated herein by reference).
10.11	— Second Amendment to Two Bridge Point Lease Agreement dated October 13, 1997 between Investors Life Insurance Company of North America and Brigham Oil & Gas, L.P. (filed as Exhibit 10.9.2 to Brigham's Registration Statement on Form S-1 (Registration No. 333-53873), and incorporated herein by reference).
10.12	— Letter dated April 17, 1998 exercising Right of First Refusal to Lease '3rd Option Space' (filed as Exhibit 10.9.3 to Brigham's Registration Statement on Form S-1 (Registration No. 333-53873), and incorporated herein by reference).
10.13	— Third Amendment to Two Bridge Point Lease Agreement dated November 1998 between Hub Properties Trust and Brigham Oil & Gas, L.P.
10.14	— Fourth Amendment to Two Bridge Point Lease Agreement dated February 7, 2002 between Hub Properties Trust and Brigham Oil & Gas, L.P.
10.15	— Fifth Amendment to Two Bridge Point Lease Agreement dated December 20, 2004 between Hub Properties Trust, a Maryland real estate investment trust, and Brigham Oil & Gas, L.P.
10.16	— Form of Indemnity Agreement between the Registrant and each of its executive officers (filed as Exhibit 10.28 to Brigham's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.17	— Registration Rights Agreement dated February 26, 1997 by and among Brigham Exploration Company, General Atlantic Partners III L.P., GAP-Brigham Partners, L.P., RIMCO Partners, L.P. II, RIMCO Partners L.P. III, and RIMCO Partners, L.P. IV, Ben M. Brigham, Anne L. Brigham, Harold D. Carter, Craig M. Fleming, David T. Brigham and Jon L. Glass (filed as Exhibit 10.29 to Brigham's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.18*	— 1997 Director Stock Option Plan, as amended as of April 9, 2003. (filed as Exhibit 10.15 to Brigham's Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference
10.19	— Form of Employee Stock Ownership Agreement (filed as Exhibit 10.31 to Brigham's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.20	— Agreement and Assignment of Interest in Geophysical Exploration Agreement, Esperson Dome Project, dated November 1, 1994, by and between Brigham Oil & Gas, L.P. and Vaquero Gas Company (filed as Exhibit 10.33 to Brigham's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.21	— Agreement and Partial Termination of Agreement and Assignment of Interest in Geophysical Exploration Agreement, Esperson Dome Project dated March 14, 2003, by and between Brigham Oil & Gas, L.P. and Vaquero Gas Company, Incorporated (filed as Exhibit 10.53 to Brigham's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 and incorporated herein by reference)
10.22	— Proposed Trade Structure, RIMCO/Tigre Project, Vermillion Parish, Louisiana, among Brigham Oil & Gas, L.P., Tigre Energy Corporation and Resource Investors Management Company (filed as Exhibit 10.36 to Brigham's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.23	— Letter relating to Proposed Trade Structure, RIMCO/Tigre Project, dated January 31, 1997, from Resource Investors Management Company to Brigham Oil & Gas, L.P. (filed as Exhibit 10.36.1 to Brigham's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).

Number	Description
10.24	— Agreement dated March 6, 2000 by and between RIMCO Production Co., Tigre Energy Corporation and Brigham Oil & Gas, L.P. regarding modifications to the Proposed Trade Structure, RIMCO/Tigre Project, dated January 31, 1997 (filed as Exhibit 10.31.2 to Brigham's Annual Report on Form 10-K for the year ended December 31, 1999 and incorporated by reference herein).
10.25	— Form Change of Control Agreement dated as of September 20, 1999 between Brigham Exploration Company and certain Officers (filed as Exhibit 10.3 to Brigham's Quarterly Report on Form 10-Q for the fiscal quarter ended September 30, 1999 and incorporated by reference herein).
10.26	— Joint Development Agreement, dated as of February 10, 1999, by and between Brigham Oil & Gas, L.P. and Aspect Resources LLC. (filed as Exhibit 10.65 to Brigham's Annual Report on Form 10-K for the year ended December 31, 1999, and incorporated herein by reference).
10.27	— First Amendment, dated as of May 10, 1999, to that certain Joint Development Agreement entered into effective as of February 10, 1999, by and between Brigham Oil & Gas, L.P. and Aspect Resources LLC. (filed as Exhibit 10.65.1 to Brigham's Annual Report on Form 10-K for the year ended December 31, 1999, and incorporated herein by reference).
10.28	— Acquisition and Participation Agreement dated October 21, 1999, by and between Brigham Oil & Gas, L.P. and Aspect Resources LLC. (filed as Exhibit 10.65.2 to Brigham's Annual Report on Form 10-K for the year ended December 31, 1999, and incorporated herein by reference).
10.29	— Letter agreement, dated as of December 30, 1999, regarding amendments to Joint Development Agreement, dated as of February 10, 1999, as amended, by and between Brigham Oil & Gas, L.P. and Aspect Resources LLC. (filed as Exhibit 10.65.3 to Brigham's Annual Report on Form 10-K for the year ended December 31, 1999, and incorporated herein by reference).
10.30	— Letter agreement dated as of September 6, 1999 between Brigham Oil & Gas, L.P. and Brigham Land Management Company, Inc. regarding work to be performed within Brigham's Angelton Project. (filed as Exhibit 10.66 to Brigham's Annual Report on Form 10-K for the year ended December 31, 1999, and incorporated herein by reference).
10.31	— Registration Rights Agreement dated November 1, 2000 by and between Brigham Exploration Company, DLJ MB Funding III, Inc., and DLJ ESC II, LP. (filed as Exhibit 10.10 to Brigham's Current Report on Form 8-K, as amended (filed November 8, 2000), and incorporated herein by reference).
10.32	— First Amendment to Registration Rights Agreement, dated March 5, 2001, by and among Brigham Exploration Company, DLJMB Funding III, Inc., DLJ Merchant Banking Partners III, LP, DLJ ESC II, LP and DLJ Offshore Partners III, CV (filed as Exhibit 10.71 to Brigham's Annual Report on Form 10-K for the year ended December 31, 2000 (filed March 23, 2001), and incorporated herein by reference).
10.33	— Registration Rights Agreement dated December 20, 2002 between Brigham Exploration Company and Shell Capital Inc. (filed as Exhibit 10.50 to Brigham's Annual Report on Form 10-K for the year ended December 31, 2002 and incorporated herein by reference).
10.34	— Second Amendment to Registration Rights Agreement dated December 21, 2002 between Brigham Exploration Company and Credit Suisse First Boston Entities (filed as Exhibit 10.51 to Brigham's Annual Report on Form 10-K for the year ended December 31, 2002 and incorporated herein by reference).
10.35	— Third Amendment to Registration Rights Agreement May 24, 2004 between Brigham Exploration Company and Credit Suisse First Boston Entities (filed as Exhibit 99.1 to Brigham's Current Report on Form 8-K (filed July 20, 2004), and incorporated herein by reference).
10.36	— Third Amended and Restated Credit Agreement, dated January 21, 2005 between Brigham Oil & Gas, L.P., Société Générale, Societe Generale, The Royal Bank of Scotland plc and Bank of America, N.A.
10.37	— Amended and Restated Subordinated Credit Agreement, dated March 21, 2003 between Brigham Oil & Gas, L.P., and The Royal Bank of Scotland plc (filed as Exhibit 10.54 to Brigham's Annual Report on Form 10-K for the year ended December 31, 2002 and incorporated herein by reference).

Number	Description
10.38	— Second Amendment to Amended and Restated Subordinated Credit Agreement dated May 4, 2004 between Brigham Oil & Gas, L.P., and The Royal Bank of Scotland plc (filed as Exhibit 99.3 to Brigham's Current Report on Form 8-K (filed July 20, 2004), and incorporated herein by reference).
10.39	— Second Amended and Restated Subordinated Credit Agreement dated January 21, 2005 between Brigham Oil & Gas, L.P., and The Royal Bank of Scotland plc.
10.40	— Fourth Amended and Restated Credit Agreement, dated June 29, 2005 between Brigham Oil & Gas, L.P., Bank of America, N.A., The Royal Bank of Scotland plc, BNP Paribas and Banc of America Securities LLC. (filed as Exhibit 10.1 to Brigham's Quarterly Report on Form 10-Q for the six month period ended June 30, 2005 and incorporated herein by reference).
10.41	— The Resignation of Agent, Appointment of Successor Agent and Assignment of Security Instruments dated June 29, 2005 by and among Brigham Oil & Gas, L.P., Sociėtė Gėnėrale and Bank of America, N.A. (filed as Exhibit 10.2 to Brigham's Quarterly Report on Form 10-Q for the six month period ended June 30, 2005 and incorporated herein by reference).
10.42	— First Amendment to Second Amended and Restated Subordinated Credit Agreement dated June 29, 2005, between Brigham Oil & Gas, L.P., and The Royal Bank of Scotland plc. (filed as Exhibit 10.3 to Brigham's Quarterly Report on Form 10-Q for the six month period ended June 30, 2005 and incorporated herein by reference).
10.43	— Second Amended and Restated Intercreditor and Subordination Agreement, dated January 21, 2005 (filed as Exhibit 10.4 to Brigham's Quarterly Report on Form 10-Q for the six month period ended June 30, 2005 and incorporated herein by reference).
10.44	— First Amendment to the Second Amended and Restated Intercreditor and Subordination Agreement (filed as Exhibit 10.5 to Brigham's Quarterly Report on Form 10-Q for the six month period ended June 30, 2005 and incorporated herein by reference).
10.45*	— Form of Restricted Stock Agreement (filed as Exhibit 10.1 to Brigham's Quarterly Report on Form 10-Q for the nine month period ended September 30, 2005 and incorporated herein by reference).
10.46†	— Second Amendment to Second Amended Restated Subordinated Credit Agreement dated December 19, 2005 between Brigham Oil & Gas L.P., and The Royal Bank of Scotland plc.
21†	— Subsidiaries of the Registrant.
23.1†	— Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.
23.2†	— Consent of Cawley Gillespie & Associates, Inc.
31.1†	— Certification of Chief Executive Officer pursuant to Sec. 302 of the Sarbanes-Oxley Act of 2002
31.2†	— Certification of Chief Financial Officer pursuant to Sec. 302 of the Sarbanes-Oxley Act of 2002
32.1†	— Certification of Chief Executive Officer pursuant to 18 U.S.C. SECTION 1350
32.2†	— Certification of Chief Financial Officer pursuant to 18 U.S.C. SECTION 1350

* Management contract or compensatory plan.

† Filed herewith.

CORPORATE MANAGEMENT

Ben "Bud" M. Brigham

President
Chief Executive Officer
Chairman of the Board

Eugene B. Shepherd, Jr.

Executive Vice President &
Chief Financial Officer

David T. Brigham

Executive Vice President of
Land and Administration &
Director

A. Lance Langford

Executive Vice President of
Operations

Jeffery E. Larson

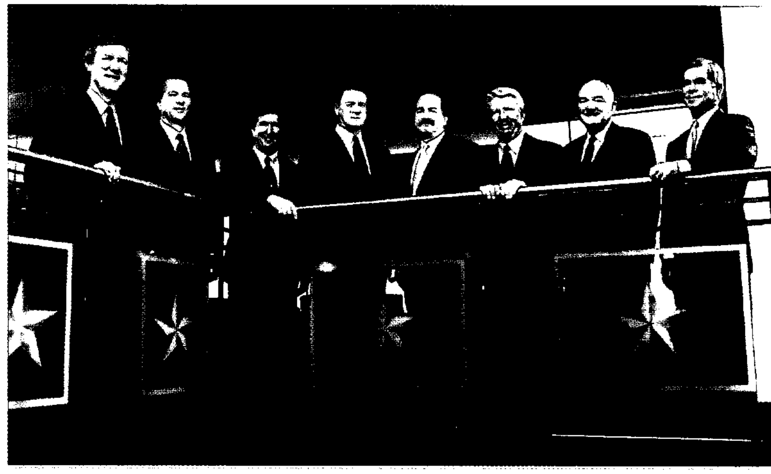
Executive Vice President of
Exploration

Malcom O. Brown

Vice President
Controller

Warren J. Ludlow

General Counsel
Corporate Secretary



Annual Shareholders Meeting

Brigham Exploration Company will hold its annual meeting of shareholders at 10:00 am on June 1, 2006 at its corporate headquarters in Austin, Texas.

Information Requests

Anyone wishing to obtain more information about Brigham Exploration Company, including copies of Brigham's Form 10-K and other filings with the Securities and Exchange Commission without charge, should direct requests to Investor Relations at 512.427.3444 or visit our website at www.bexp3d.com.

Common Stock Data

Brigham completed its initial public offering of common stock on May 8, 1997. Brigham's common stock trades on The Nasdaq Stock Market under the symbol BEXP.

Forward Looking Statements

Except for the historical information contained herein, the matters discussed in this Annual Report are forward looking statements that are based upon current expectations. Important factors that could cause actual results to differ materially from those in the forward looking statements include risks inherent in exploratory drilling activities, the timing and extent of changes in commodity prices, unforeseen engineering and mechanical or technological difficulties in drilling wells, availability of drilling rigs, land issues, federal and state regulatory developments and other risks more fully described in Brigham's filings with the Securities and Exchange Commission.

Corporate Headquarters

6300 Bridge Point Parkway, Building 2, Suite 500
Austin, Texas 78730
Phone: 512.427.3300
Fax: 512.427.3400

BOARD OF DIRECTORS

(left to right)

Stephen P. Reynolds
Former President of GAP III Investors, Inc.

David T. Brigham
Executive Vice President of
Brigham Exploration Company

Ben "Bud" M. Brigham
President, CEO and Chairman of the Board

Stephen C. Hurley
President of Hunt Oil Company

Steven A. Webster
Co-Managing Partner of
Avista Capital Partners

Harold D. Carter
Former President and Chief Operating
Officer of Sabine Corporation

Hobart A. Smith
Consultant for Smith International, Inc.

R. Graham Whaling
Chairman and CEO of Laredo Energy, LP

CORPORATE INFORMATION

Independent Auditors

PricewaterhouseCoopers LLP
Houston, Texas

Legal Counsel

Thompson & Knight L.L.P.
Dallas, Texas

Independent Petroleum Engineers

Cawley, Gillespie & Associates, Inc.
Fort Worth, Texas

Stock Transfer Agent and Registrar

American Stock Transfer and Trust Company
59 Maiden Lane, Plaza Level
New York, NY 10038

BRIGHAM
Exploration Company

6300 BRIDGE POINT PARKWAY, BUILDING 2, SUITE 500, AUSTIN, TEXAS 78730 PHONE: 512.427.3300 FAX: 512.427.3400

WWW.BEXP3D.COM NASDAQ: BEXP