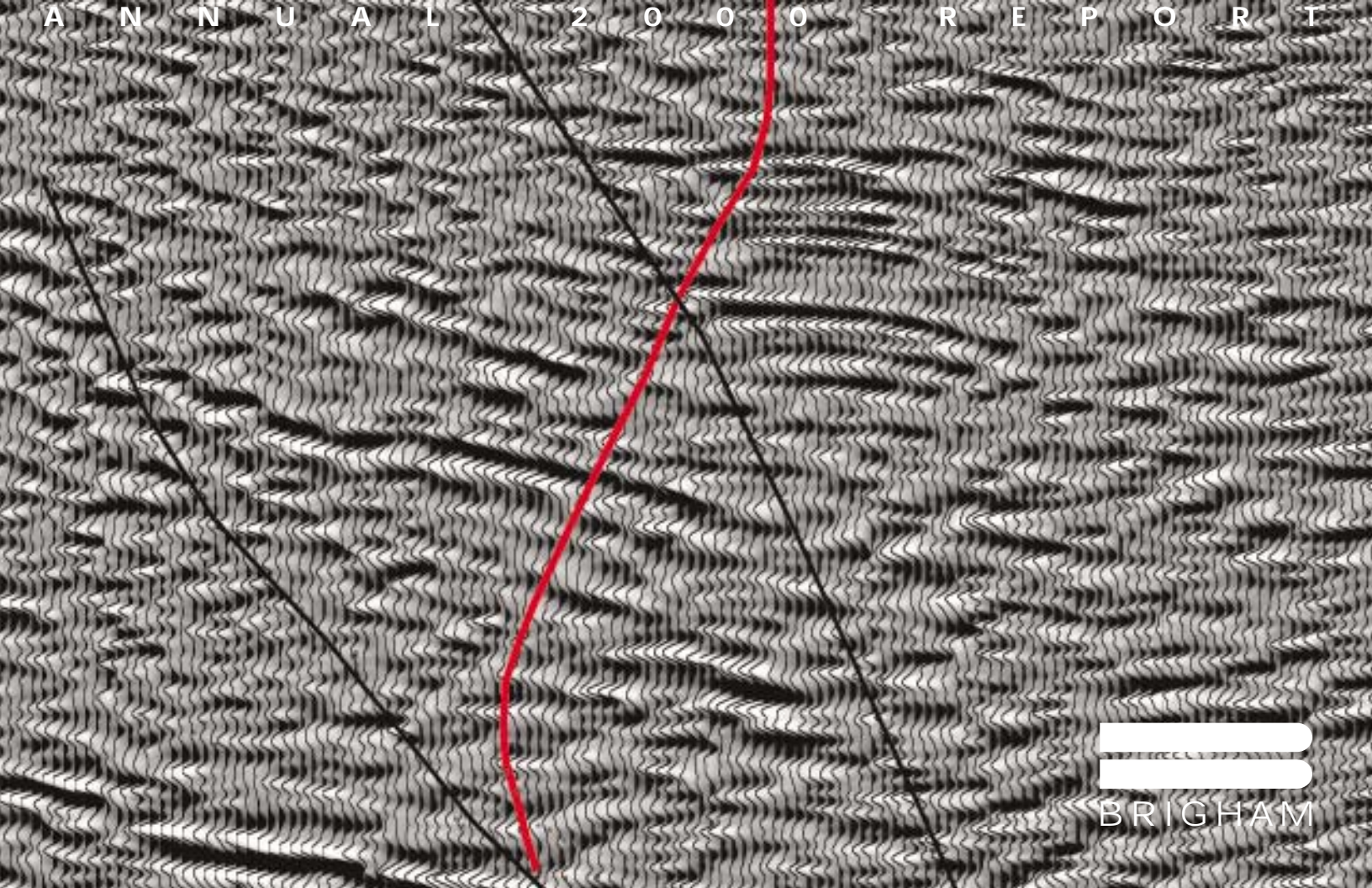


BRIGHAM EXPLORATION COMPANY



A N N U A L 2 0 0 0 R E P O R T



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.

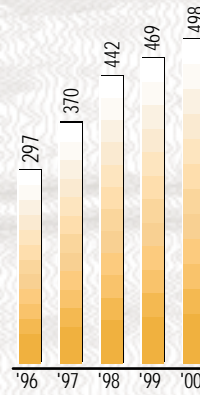
ASSETS

Brigham's principal assets include: (1) its team of experienced technical staff, including eleven geologists and geophysicists and five petroleum engineers, (2) its inventory of high quality drilling prospects within its 3-D seismic project portfolio that encompasses more than three million acres, and (3) its 95 Bcfe proved reserve base at year-end 2000 that is 82% natural gas and 52% developed.

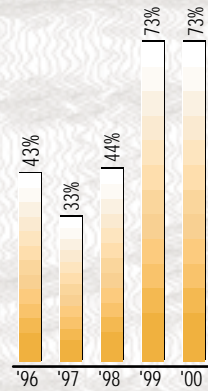
COMPETITIVE ADVANTAGES

Its ten-year record of 3-D seismic-based exploration and development drilling has created significant competitive advantages for Brigham, the most important of which are (1) its extensive knowledge base and track record in the effective utilization of technology to find oil and gas, and (2) its multi-year drilling inventory of natural gas prospects that has produced several 100+ potential Bcfe discoveries in the past eighteen months.

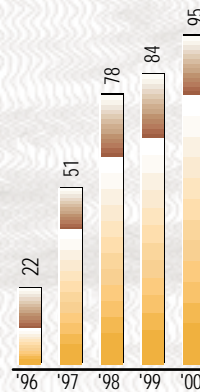
Cumulative Wells Drilled



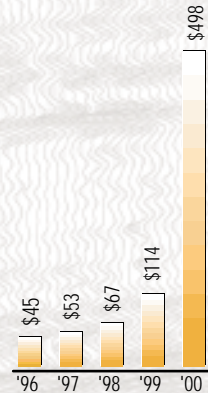
Drilling as % of CapEx



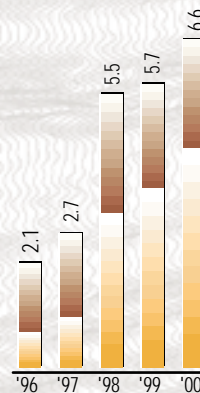
Net Proved Reserves (Bcfe)



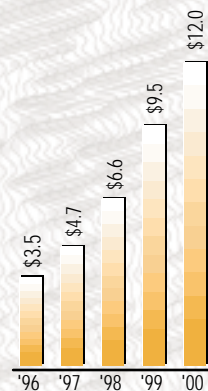
PV10% Value (\$MM)



Net Production (Bcfe)



EBITDA (\$MM)



Oil
Gas

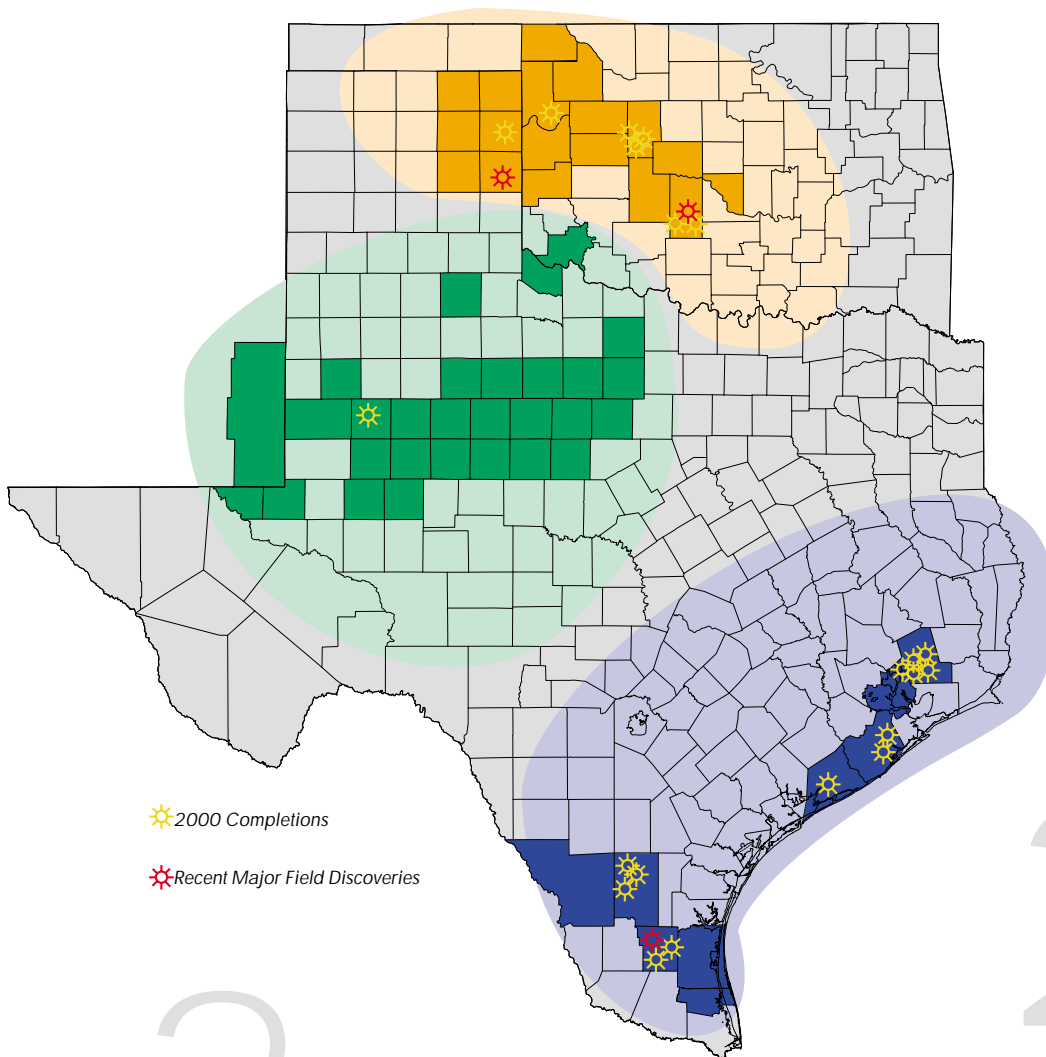
CORE PROVINCES

Brigham's exploration and development activities are concentrated in three core provinces: (1) the Anadarko Basin of western Oklahoma and the Texas Panhandle, (2) the onshore Texas Gulf Coast, and (3) West Texas.

Brigham has increasingly focused its activities in selected trends where it has developed superior geological, geophysical and operational expertise. In 1999 and 2000, this focus resulted in an 80% completion rate, an average all-in finding cost of \$0.85 per Mcfe, and three major field discoveries.

Anadarko Basin	
Gross 3-D Sq. Miles	2,062
Net Proved Reserves (Bcfe)	54
Percent Gas	92%
PV10% Value (\$MM)	\$295

Total Company	
Gross 3-D Sq. Miles	5,122
Net Proved Reserves (Bcfe)	84
Percent Gas	82%
PV10% Value (\$MM)	\$498



☀️ 2000 Completions

★ Recent Major Field Discoveries

West Texas & Other	
Gross 3-D Sq. Miles	1,964
Net Proved Reserves (Bcfe)	9
Percent Gas	15%
PV10% Value (\$MM)	\$27

Gulf Coast	
Gross 3-D Sq. Miles	1,096
Net Proved Reserves (Bcfe)	32
Percent Gas	85%
PV10% Value (\$MM)	\$176



Ben M. "Bud" Brigham

Our current strategic emphasis includes four key elements:

Drilling:

Focus resources on drilling of our established 3-D delineated project inventory

Balance:

Maintain an active, high potential exploration program, yet continue to allocate an increasing percentage of our drilling expenditures toward the development of our new field discoveries

Profits:

Improve cash flow margins and return on invested capital by continuing to reduce per unit finding and operating cost components

Returns:

Selectively monetize non-producing assets to recoup capital investments and improve project rates of return

It is my pleasure to report to our shareholders on our accomplishments during 2000. While our industry is benefiting from remarkably robust energy prices, our achievements were the product of the quality of our people, our assets and our dynamic and entrepreneurial spirit. Given these attributes, and our accomplishments, I don't know of a small independent better positioned to capitalize on the current industry environment. That's a bold statement, but consider the following four factors:

Three Significant Field Discoveries

In my last shareholder letter I discussed our late 1999 Home Run Field discovery in our Gulf Coast province. We've only just begun to reap the financial rewards to be generated from this field. In February 2000 we completed the discovery well, and in August 2000 we successfully brought on line a second well. We currently have two additional wells completing, with three more development wells planned for 2001. The Home Run Field could require 20 additional wells for full development. Furthermore, two offsetting fault blocks should be tested in 2001 that have the potential to double our drilling inventory in this project.

Early in 2000 we had another significant discovery, this time in our Anadarko Basin province. Our Springer Bar discovery is a remarkably large field, approximately nine miles long and two miles wide. The field should ultimately require over ten wells for full development, with five wells planned in 2001.

Late in 2000 we successfully completed our third significant field discovery, a 25,000 foot Hunton test in the Anadarko Basin. This well ranks as the deepest well drilled in Texas in 2000. After re-entering another operator's dry hole, we kicked out of the existing borehole at a depth of about 15,000 feet, and subsequently directionally drilled to a location 3,000 feet to the northwest at a depth of approximately 25,000 feet. The integration of 3-D seismic with the latest in drilling and completion technologies enabled us to save over \$1 million in drilling and completion costs, and resulted in a Hunton field discovery with potential reserves of up to 250 Bcfe. We expect to drill at least one offset well in this field in 2001.

These three field discoveries, combined with our other recent successes, provide us with a growing portfolio of more predictable, yet high return development drilling. As a result, we plan to allocate over 50% of our 2001 drilling expenditures to development projects.

Ten Year Track Record of Drilling Success

Since our inception in 1990, we've drilled nearly 500 3-D delineated wells, demonstrating an ability to discover reserves with the drill bit at attractive finding costs. Our inception-to-date drilling cost is \$0.75 per Mcfe. Over the past two years, we've achieved a drilling cost of \$0.62 per Mcfe, which is particularly attractive since a significant percentage of our 2000 capital was spent on drilling our proved undeveloped inventory. Another excellent indication of our recent drilling success is our 2000 proved developed drilling cost of only \$0.64 per Mcfe. Further, every \$1 we invested in drilling in 2000 added over \$4.50 in proved developed PV10% reserve value, based on recent strip prices.

By harvesting our prior investments in 3-D seismic and land, the vast majority of our current capital expenditures are being directed to growth in reserves and cash flow. In 1999 and 2000 our all-in finding cost averaged only \$0.85 per Mcfe, certain

M O M E N T U M

to rank among the lowest of our peers. In 2001, our goal is to again achieve a proved developed drilling cost below \$0.80 per Mcfe, and to add \$4 in PV10% reserve value for every \$1 we invest in drilling.

Expansive Inventory of Drilling Locations

While other companies are running out of prospects, we have a multi-year inventory of drilling locations. Given substantially improved commodity prices, our drilling of this inventory is generating unprecedented economics in the field. For example, our Price #2 Springer discovery began producing in May 2000 at a curtailed rate of 5.6 MMcfe per day, and pipeline capacity was finally increased in December to 7.2 MMcfe per day. Despite the curtailed production rates, this well paid out its completed well cost approximately six times in its first nine months of production. This well is not unique. Our recent Frio bright spot discovery, which we've now successfully offset, came on line at over 11 MMcfe per day, and the well paid out its completed well cost in less than two weeks. These wells are indicative of the economic value that exists in our prospect inventory, and our accelerated drilling of this inventory will generate improved financial results in 2001.

Reduced Debt and Improved Hedge Position

Our debt levels and hedge position limited our cash flow expansion in 2000. However, our cost structure is significantly improved in 2001, in part due to \$20 million in debt reduction achieved in 2000. Our realized natural gas price should increase as our average hedge price improves and the percentage of our production that is hedged declines. As a result, we expect a substantial improvement in our operating margins in 2001, providing investors with the opportunity to participate in a significant cash flow expansion.

In closing, we remain convinced that our company is uniquely positioned to capitalize on the current industry environment. Combining high commodity prices with our track record for successful drilling, our inventory of natural gas drilling locations and our improved financial position will lead to substantially improved financial performance in 2001.

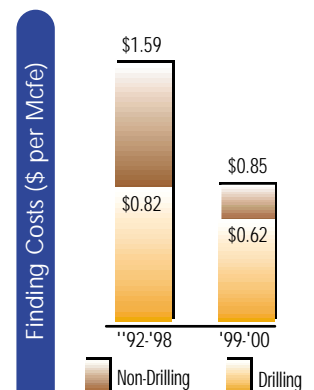
For our 2000 accomplishments, of which I am very proud, credit goes to our dedicated employees and business partners. Management continues to appreciate the support and perseverance of all our friends and fellow shareholders. We expect to deliver an exciting and rewarding 2001.



Ben M. Brigham
Chairman of the Board
President and Chief Executive Officer
March 23, 2001

LETTER TO SHAREHOLDERS

Our strategic focus on the harvesting of our prior 3-D seismic project investments during the past two years has resulted in a dramatic improvement in finding costs:



M E N T

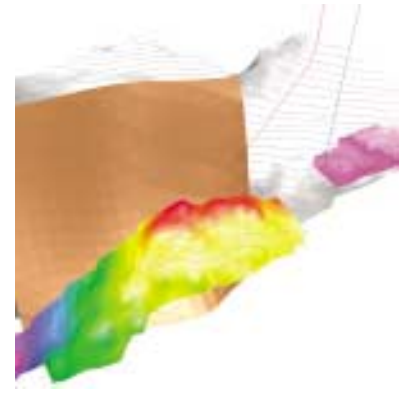
OPERATIONAL HIGHLIGHTS

Brigham's 2000 drilling program demonstrated the significant growth potential inherent in its 3-D seismic project portfolio. In the last eighteen months, Brigham has made three major new field discoveries. In late 1999, Brigham found a significant Lower Vicksburg field in South Texas. During 2000, Brigham discovered substantial Springer Bar and Hunton fields in the Anadarko Basin. Each of these new fields has gross reserve potential in excess of 100 Bcfe, thereby supporting active development drilling for several years.

Wildcat Project: Hunton Discovery

Brigham's Wildcat and Panther Projects consist of nearly 150 square miles of continuous 3-D seismic data covering approximately 93,440 acres in the southern portion of the Texas Panhandle in Wheeler County, Texas and Beckham County, Oklahoma. The primary exploration targets within these projects are high potential, structural Hunton features at depths ranging from 7,500 to 25,000 feet.

In July 2000, Brigham spud a high potential Hunton test offsetting a Hunton well that has produced over 15 Bcfe to date in its Wildcat Project. Drilled to a total depth of over 25,000 feet, Brigham completed the well in the targeted Hunton formation in late December 2000. The well encountered approximately 1,200 feet of gross (240 feet of net) pay in three Hunton intervals. The well began producing to sales from one Hunton interval in early January 2001 at rates of approximately 9.5 MMcf of natural gas and 90 barrels of condensate per day, or 5.1 net MMcfe per day. Current plans include stimulation of the two remaining Hunton pay intervals in the discovery well, and the drilling of at least one development well during 2001. Brigham has booked estimated proved reserves of approximately 21 gross Bcfe (or 10.7 net Bcfe) attributable to this Hunton producer at December 31, 2000, and it believes this Hunton field could ultimately produce up to 250 Bcfe of gross reserves. In addition to this discovery, Brigham has also assembled a significant acreage position along trend and may drill another high potential exploratory Hunton test in early 2002.



Current plans include stimulation of the two remaining Hunton pay intervals in the discovery well, and the drilling of at least one development well during 2001. Brigham has booked estimated proved reserves of approximately 21 gross Bcfe (or 10.7 net Bcfe) attributable to this Hunton producer at December 31, 2000, and it believes this Hunton field could ultimately produce up to 250 Bcfe of gross reserves. In addition to this discovery, Brigham has also assembled a significant acreage position along trend and may drill another high potential exploratory Hunton test in early 2002.

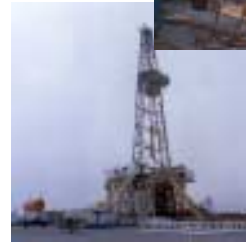
Diablo Project: Home Run Field Development

Brigham's Diablo Project covers 57 square miles in Brooks County, Texas, and targets shallow Frio and deep Vicksburg producing horizons. Brigham retains a 34% working interest in this joint exploration project in which it and a major integrated oil company control approximately 10,000 gross and net acres of leasehold.

In the fourth quarter of 1999, Brigham confirmed a major Lower Vicksburg field discovery, the Home Run Field, in its Diablo Project with the completion of the Palmer State #2 well. After successive fracture stimulations during January and February 2000, the well was successfully commingled to produce simultaneously from four Lower Vicksburg intervals. The Palmer State #2 began flowing to sales as a commingled producer in late February 2000 at average daily production rates of 10.1 MMcf of natural gas and 650 barrels of condensate, or approximately 4 net MMcfe. In mid-March 2001, this well was producing 3.1 MMcfe per day, or 0.9 net MMcfe per day.

DEVELOPME

IMPACT



Washed over three failed cut-off attempts and 160 feet of 9-5/8" casing. Ran a tie back string of new casing to 5,100 feet.

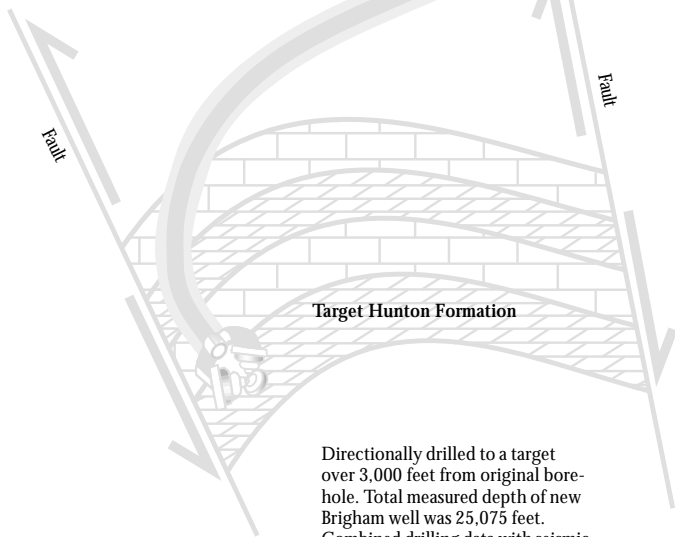
9-5/8" casing at 12,500 feet.

Kicked out of original wellbore at 15,000 feet. Built to a maximum angle of 35°.

Original wellbore drilled by another operator to 22,550 feet in 1982, then plugged and abandoned.

MILLS RANCH DISCOVERY

Brigham's successful late 2000 completion of its new Hunton field discovery well in its Wildcat Project is indicative of the asset value inherent in Brigham's 3-D seismic project portfolio, as well as its geologic and operational expertise. Combining its skills in 3-D seismic interpretation, geologic assessment and drilling operations evaluation, Brigham's project team was able to successfully re-enter a previously drilled well to sidetrack and directionally drill the deepest well in Texas during 2000. This synergistic integration of complementary technologies saved an estimated \$1 million in drilling costs. The illustration to the left depicts this complex project which resulted in the discovery of up to 250 Bcfe of potential reserves.



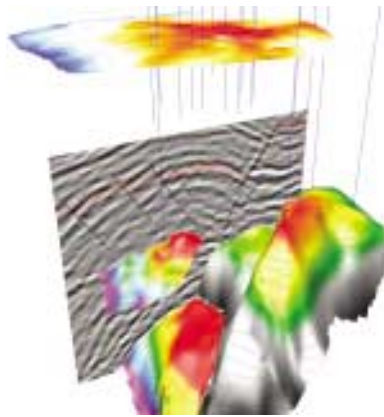
Directionally drilled to a target over 3,000 feet from original borehole. Total measured depth of new Brigham well was 25,075 feet. Combined drilling data with seismic information to avoid pushing through a trapping fault.

NT

OPERATIONAL HIGHLIGHTS

Brigham spud three development wells in the Home Run Field during 2000. The first development well, the Palmer State #3, began producing in early August 2000 at an initial rate of 12.3 MMcf of natural gas and 450 barrels of condensate per day, or 4.4 net MMcfe. In late October 2000, Brigham spud the Palmer State #4 as an updip offset to the Palmer State #2 field confirmation well. In mid-March 2001, the Palmer State #4 was being completed and fracture stimulated in the target Lower Vicksburg objectives and is expected to be producing to sales through commingled completions by the end of the first quarter. The third Home Run field development well, the D.J. Sullivan #C-25, was spud in late December 2000 and was also being completed and fracture stimulated in mid-March 2001. Full commingled production

is expected from both the Palmer State #4 and D.J. Sullivan #C-25 wells in April 2001 at initial rates similar to the Palmer State #2 and #3 producers. Brigham retains net revenue interests ranging from 26% to 29% these three Home Run Field development wells.



Brigham's 3-D interpretative mapping indicates that the Home Run Field reservoirs have over 500 feet of relief and cover approximately 1,100 acres with estimated potential gross reserves ranging from 80 Bcfe to over 200 Bcfe (or 23 Bcfe to 58 Bcfe net). Brigham had 16.5 net Bcfe of estimated proved reserves attributable to the Home Run Field as of December 31, 2000. In addition to the production additions from the Palmer State #4 and D.J. Sullivan #C-25 wells, Brigham's planned drilling program includes three additional develop-

ment wells to be drilled in the Home Run Field during 2001.

The Home Run Field is located upthrown from two large, untested 3-D delineated Vicksburg structures (Mariposa and Floyd) in adjacent fault blocks that cover approximately 1,200 acres. Brigham plans to spud an exploratory test of the estimated 1,000 acre Mariposa fault block in the second quarter of 2001. This 3-D delineated Vicksburg structure is located beneath the shallower Mariposa Field that has produced in excess of 187 Bcf of natural gas from the Frio. The estimated 200 acre Floyd fault block is an apparent four-way Lower Vicksburg closure that Brigham plans to test in early 2002.

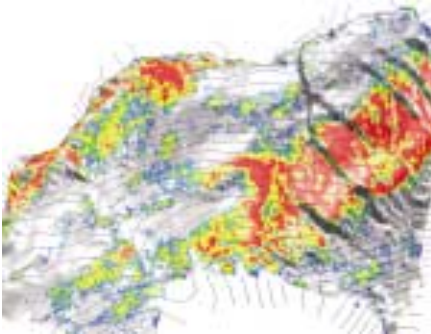
[Bearcat Project: Springer Bar Discovery](#)

Brigham's Bearcat Project consists of 59 square miles of 3-D seismic data covering approximately 37,760 acres in the prolific Carter-Knox anticline in Grady County, Oklahoma. This project targets 3-D seismic amplitude-related shallow Pennsylvanian-aged channel sands and deep marine bar sands in the Springer section.

During its 2000 drilling program, Brigham participated in three wells that confirmed the discovery of a potentially significant Springer Bar field that is estimated

F O C U S

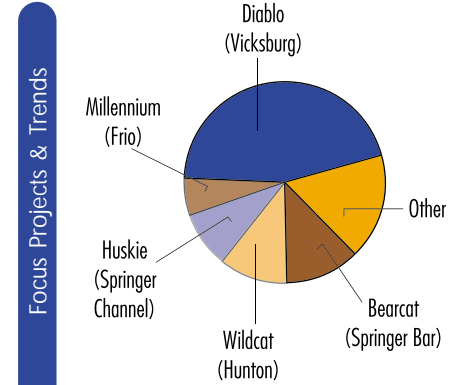
to be approximately nine miles long and two miles wide. The initial exploratory test of this 3-D delineated Springer Bar objective, the Nix #1 (20% WI), encountered approximately 90 feet of Springer-aged sand that confirmed Brigham's seismic interpretation of this feature. Subsequent to this initial discovery, Brigham participated in two development wells in this new field. The Pitchford #1 (32% WI) reached a total depth of 15,140 feet and logged 31 feet of net pay in the targeted Britt section with significant porosity improvement relative to the Nix #1. After fracture stimulation of this Britt interval, the well began producing to sales at a rate of approximately 2.2 MMcf of natural gas and 140 barrels of condensate per day, or approximately 3 MMcfe per day, in December 2000. The second development well, the McCasland Farms #1 (23% WI), was spud in late October 2000 and logged 32 feet of net pay. This well was being completed and fracture stimulated in March 2001 prior to commencement of production.



Brigham currently owns over 2,500 net acres in nine sections over this Springer Bar feature, and anticipates participating in up to ten additional wells to fully develop the field. In its 2001 drilling program, Brigham plans to participate in the drilling of up to five development wells in this Springer Bar field in which it expects to retain working interests generally ranging from 20% to 25%.

2001 Program: Leveraging Recent Successes

Continuing its strategy to harvest its prior 3-D seismic project investments, Brigham intends to focus substantially all of its efforts and available capital resources in 2001 to the drilling and monetization of its highest grade prospects within its over 5,000 square mile inventory of 3-D seismic data. Brigham's 2001 capital expenditure budget is estimated to be \$32 million, which includes approximately \$22 million for drilling projects, \$4 million for leasing and G&G activities, and \$6 million for capitalized overhead and interest costs. Brigham's planned 2001 drilling program consists of a balanced blend of higher potential exploration tests and lower risk development drilling projects, driven to a large extent by the development of its major new field discoveries found in 1999 and 2000. Approximately 34% of budgeted 2001 drilling expenditures are targeted for exploratory prospects, 52% for development locations and the remaining 14% for development locations that are contingent upon drilling success during the year. In addition, over 80% of Brigham's budgeted drilling expenditures are focused in five project areas in the Springer and Hunton trends of the Anadarko Basin and the Vicksburg and Frio trends of the Texas Gulf Coast.



Brigham plans to leverage its recent field discoveries in its \$22 million 2001 drilling program by concentrating its planned exploration and development activities in and around its areas of recent drilling success. Over 80% of its planned drilling expenditures are focused in five project areas in the Springer Bar, Springer Channel, and Hunton trends in the Anadarko Basin and the Vicksburg and Frio trends in the Texas Gulf Coast. Through this focus, Brigham will build upon its geologic and operational knowledge base in these prolific natural gas producing trends in 2001 and beyond.

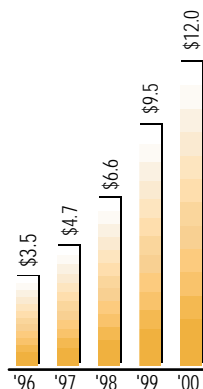
FINANCIAL HIGHLIGHTS

(\$000, except per share and per Mcfe data)

Year Ended December 31,

1996 1997 1998 1999 2000

EBITDA (\$MM)



Operating Data:

Natural Gas and Oil Sales	\$6,141	\$9,184	\$13,799	\$14,992	\$19,143
Total Revenue	6,768	9,821	14,189	15,277	19,196
EBITDA ^(a)	3,533	4,696	6,631	9,456	11,956
Operating Cash Flow ^(b)	2,360	3,506	2,182	7,532	8,581
Net Income (Loss)	(450)	(1,117) ^(c)	(33,345) ^(d)	(21,628) ^(e)	16,337 ^(f)

Per Diluted Share Data:

Operating Cash Flow Per Share	\$0.26	\$0.31	\$0.17	\$0.53	\$0.53
Net Income (Loss) Per Share	(\$0.05)	(\$0.10) ^(c)	(\$2.64) ^(d)	(\$1.53) ^(e)	\$1.01 ^(f)
Wt. Avg. Shares (000)	8,929	11,198	12,832	14,152	16,241

Capital Expenditure Data:

Net Land and G&G	\$6,066	\$22,881	\$40,784	(\$2,430)	\$583
Net Drilling	6,047	19,191	36,857	10,750	18,461
Property Acquisitions (Sales)	0	13,500	1,020	(17,143)	0
Capitalized G&A and Interest	1,826	3,460	5,770	6,559	6,300
Net Capital Costs	\$13,939	\$59,032	\$84,431	(\$2,264)	\$25,344

Balance Sheet Data:

Cash and Cash Equivalents	\$1,447	\$1,701	\$2,569	\$2,742	\$837
Net Oil and Gas Properties	28,005	84,294	134,317	112,066	129,490
Total Assets	33,614	92,519	150,516	125,683	146,911
Total Debt	24,000	32,000	94,786	97,341	82,000
Stockholders' Equity	3,244	43,313	24,681	8,998	34,757

Per Mcfe Data:

Natural Gas and Oil Sales	\$2.98	\$2.94	\$2.08	\$2.39	\$2.90
Workstation Revenue	0.31	0.20	0.06	0.05	0.01
Total Revenue	\$3.29	\$3.14	\$2.14	\$2.44	\$2.91
Lease Operating Expenses	0.35	0.37	0.33	0.36	0.32
Production Taxes	0.18	0.18	0.13	0.15	0.27
Net G&A Expenses	1.07	1.14	0.70	0.56	0.47
Margin Per Mcfe	\$1.69	\$1.45	\$0.98	\$1.37	\$1.85

(a) EBITDA represents net income plus income taxes, interest expense, depreciation, depletion and amortization expenses and other non-cash items.

(b) Operating cash flow represents net income plus DD&A expenses, deferred income taxes and other non-cash items.

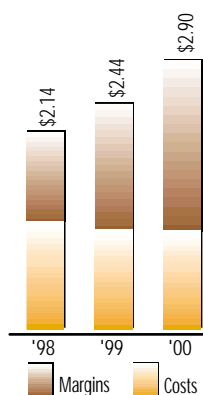
(c) Includes a net \$1.2 million (\$0.10 per diluted share) non-cash deferred income tax charge related to Brigham's conversion from a partnership to a corporation in 1997.

(d) Includes a \$25.9 million (\$2.05 per diluted share) capitalized ceiling impairment in 1998.

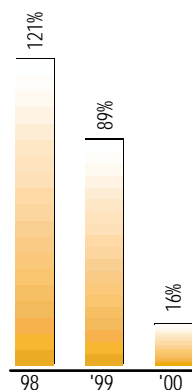
(e) Includes a \$12.2 million (\$0.86 per diluted share) loss on sale of natural gas and oil properties in 1999.

(f) Includes a \$32.3 million (\$1.99 per diluted share) gain on refinancing of debt in 2000.

Operating Margins (\$ per Mcfe)



Debt / PV10%



RESULTS

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2000

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

(State or other jurisdiction of
incorporation or organization)

6300 Bridge Point Parkway

Building 2, Suite 500

Austin, Texas

(Address of principal executive offices)

75-2692967

(I.R.S. Employer
Identification No.)

78730

(Zip Code)

(512) 427-3300

(Registrant's telephone number, including area code)

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

<u>Title of Each Class</u>	<u>Name of Each Exchange on Which Registered</u>
None	None

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

Common Stock, \$.01 par value

(Title of Class)

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.

As of March 20, 2001, the Registrant had 15,988,118 shares of common stock outstanding. The aggregate market value of the common stock held by non-affiliates of the Registrant, based upon the closing sale price of the common stock on March 20, 2001, as reported on The Nasdaq Stock MarketSM, was \$22.7 million. For purposes of determination of the foregoing amount, only directors, executive officers and 10% or greater stockholders have been deemed affiliates.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement for the Registrant's 2001 Annual Meeting of Stockholders to be held on May 10, 2001, 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, 2000.

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BRIGHAM EXPLORATION COMPANY

2000 ANNUAL REPORT ON FORM 10-K

ITEM 1. BUSINESS

Overview

Brigham Exploration Company ("Brigham" or the "Company") is an independent exploration and production company that applies 3-D seismic imaging and other advanced technologies to systematically explore and develop onshore oil and natural gas provinces in the United States. Brigham focuses its activity in provinces where it believes 3-D technology may be effectively applied to generate relatively large potential reserve volumes per well and per field, high potential production rates and multiple producing objectives. Brigham's exploration activities are concentrated primarily in three core provinces:

- the Anadarko Basin of western Oklahoma and the Texas Panhandle;
- the onshore Texas Gulf Coast; and
- West Texas.

Brigham pioneered the acquisition of large-scale onshore 3-D seismic surveys for exploration, obtaining extensive 3-D seismic data and experience in capturing undiscovered oil and natural gas reserves. As of December 31, 2000, Brigham has acquired 5,122 square miles (3.3 million acres) of 3-D seismic data and has drilled 498 wells in its 3-D project areas. Brigham generates most of its exploratory projects and, therefore, has the ability to retain a sizeable working interest in these projects.

From inception in 1990 through 2000, Brigham has drilled 407 exploratory and 91 development wells on its 3-D generated prospects with an aggregate 66% completion rate and an average working interest of 30%. As of December 31, 2000, Brigham has added 162 Bcfe of net proved reserves to its reserve base, approximately 139 net Bcfe of which were discovered by Brigham through its systematic 3-D exploration drilling activities at an average net drilling cost of \$0.75 per Mcfe. In 1999 and 2000, Brigham's average net drilling cost was \$0.62 per Mcfe and its all-in net finding and development cost was \$0.85 per Mcfe.

Brigham's estimated net proved reserves as of December 31, 2000 were 95 Bcfe having an aggregate Present Value of Future Net Revenues of \$498 million, compared to estimated net proved reserves as of December 31, 1996 of 22 Bcfe having an aggregate Present Value of Future Net Revenues of \$45 million. Brigham's net proved reserve volumes at December 31, 2000 are 82% natural gas and 52% proved developed.

Business Strategy

Brigham's principal objective and business strategy is to achieve superior growth in shareholder value through the application of its systematic exploration approach, which emphasizes the integrated use of 3-D seismic imaging and other advanced technologies to reduce drilling risks and finding costs. From its inception in 1990 through 1998, Brigham achieved rapid growth in its acquisition of 3-D seismic data, identification of potential drilling locations, discovery of proved reserves and production of oil and natural gas volumes. Having acquired in excess of 5,100 square miles of 3-D seismic data in proven producing trends during this period, Brigham has been focusing its activities since 1999 on generating tangible value from its high quality inventory of 3-D delineated prospect locations through disciplined exploration and development drilling activities and selective non-producing asset sales.

Brigham completed its initial public offering of common stock in May 1997, raising approximately \$24 million to fund its accelerated 3-D seismic acquisition and exploration drilling activities. Key elements of Brigham's long-term growth strategy at its initial public offering included:

- acquiring 3-D seismic data in proven producing trends to identify and capture potential drilling locations;
- retaining significant working interests in its exploration projects to capture a greater share of the reserves discovered;
- identifying higher potential, higher impact prospects; and
- monetizing the value of its 3-D seismic investments by drilling its inventory of identified prospect locations.

During 1997 and 1998, Brigham acquired 2,360 square miles of 3-D seismic data at an average working interest of 73%, which nearly doubled its inventory of onshore 3-D seismic data to 5,122 square miles as compared to year-end 1996. Brigham's overall level of 3-D seismic acquisition during 1997 and 1998 was the most active in its history, in which Brigham generated 3-D projects where it retained higher working interests. The vast majority of this newly acquired data was located in Brigham's higher potential Anadarko Basin and Gulf Coast provinces where it has historically achieved lower average finding costs for drilling than in its West Texas province. As a result of these significant investments in 3-D seismic acquisition, processing and interpretation in proven natural gas producing trends, Brigham believes it has assembled a significant competitive knowledge base and strategic position in each of its two most active exploration provinces. Brigham further believes it has captured a high quality inventory of 3-D delineated potential drilling locations that can be monetized through the drill bit at attractive finding costs over the next several years, thereby providing opportunities for future reserve, production and cash flow growth.

Brigham's current business strategy consists of the following key elements:

- focus resources on drilling of its established 3-D delineated project inventory, most of which target natural gas prospects in proven producing trends;
- maintain an active, high potential exploration program, yet continue to allocate an increasing percentage of drilling expenditures toward the development of previous exploration successes;
- improve cash flow margins and return on invested capital by continuing efforts to reduce per unit finding and operating cost components; and
- selectively monetize non-producing assets to recoup capital investments and improve project rates of return.

Focus on Drilling

During the first eight years of its history, Brigham directed a significant portion of its resources toward the establishment of a sizeable inventory of 3-D seismic projects within proven natural gas producing trends in the Anadarko Basin and Gulf Coast. As a result of these efforts, Brigham believes it has assembled a significant asset base within these two core exploration provinces that it has only begun to monetize through drilling efforts to date. During 1999 and 2000, Brigham focused the majority of its resources toward drilling activities within its established 3-D seismic projects to generate proved reserves, production volumes and cash flow from these investments. This capital allocation focus resulted in average drilling and all-in finding and development costs for the period 1999 - 2000 of \$0.62 per Mcfe and \$0.85 per Mcfe, respectively.

Continuing to exploit its existing 3-D seismic project assets, Brigham's primary objective in 2001 is to drill the highest-grade locations within its inventory of identified drilling locations to generate continued growth in proved reserves and cash flow. Approximately 85% of Brigham's planned \$26 million exploration and development capital expenditure budget for 2001 is targeted for drilling activities within its Anadarko Basin, Texas Gulf Coast and West Texas 3-D seismic projects. With the significant competitive advantages afforded by Brigham's prior investments in 3-D seismic data within its core provinces, Brigham expects that drilling capital expenditures should represent at least 80% of its annual exploration and development capital expenditures for the foreseeable future.

Execute Active, High-Potential Drilling Program Balanced With Development of Prior Discoveries

From 1990 to 1999, the majority of Brigham's historical drilling expenditures were directed toward exploration-oriented projects. Leveraging several potentially significant new field discoveries during 1999 and 2000, Brigham's 2000 and planned 2001 drilling programs consist of a more balanced blend of exploration and development projects in trends where Brigham has achieved historical drilling success. These focus trends include the Springer Bar, Springer Channel and Hunton trends in the Anadarko Basin and the Frio and Vicksburg trends in the Texas Gulf Coast province. Of Brigham's \$22 million drilling budget planned for 2001, 34% of the expenditures relate to exploration projects and 66% are for development drilling projects that are either currently planned or contingent upon drilling success during the year. In addition, over 80% of Brigham's 2001 planned drilling budget is concentrated in five project areas where it experienced significant drilling success during 2000.

Improve Operating Margins and Return on Invested Capital

Brigham seeks to improve its return on invested capital by achieving low finding and development costs and by reducing and controlling its per unit operating costs. Brigham has achieved average drilling costs of \$0.75 per Mcfe during the past ten years. By focusing its 1999 and 2000 drilling programs within areas where it had previously experienced drilling success, Brigham achieved improved returns on its drilling investments with average drilling costs of \$0.62 per Mcfe. Importantly, Brigham's all-in finding and development costs during 1999 and 2000 were \$0.85 per Mcfe, a substantial improvement from its average finding and development costs of \$1.59 per Mcfe from inception through 1998 due to:

- Brigham's considerable prior investments in 3-D seismic and land, principally during 1997 and 1998;
- significantly lower non-drilling capital expenditures in 1999 and 2000;
- improved drilling returns achieved during 1999 and 2000; and
- sales of interests in certain 3-D seismic projects and prospects in 1999 and 2000 that provided reimbursements of previously incurred expenditures.

Brigham expects this trend toward convergence of its all-in finding and development costs and drilling costs to continue in 2001 as it continues to capitalize on its extensive inventory of 3-D delineated prospects by allocating a substantial majority of its capital expenditures to drilling within its existing 3-D seismic project areas.

During the past few years, Brigham's low per unit lease operating expenses can be attributed to:

- the relatively new nature of many of its producing wells;
- focused operations in three core provinces; and
- operating a greater percentage of the wells that it drills.

Brigham intends to continue to maintain low per unit operating expenses by:

- monitoring and controlling production efficiency from its existing producing wells;
- adding new producing wells that typically cost less to operate than more mature wells; and
- seeking to achieve operating cost efficiencies through increased economies of scale resulting from a greater concentration of producing assets within its core project areas.

Monetize Non-Producing Assets

In addition to supporting a multi-year drilling program, Brigham believes that its substantial investments in 3-D seismic data and undeveloped acreage provide a significant competitive advantage to attract participants to invest in its projects, thereby recouping a portion of its initial capital investments, typically on a promoted basis. Brigham has been effective at raising capital and attaining promoted working interests in its 3-D seismic projects throughout its history. During 1999 and 2000, Brigham raised in excess of \$15 million through the sales of interests in various 3-D seismic projects or individual drilling prospects to fund a portion of its capital expenditure program and satisfy working capital requirements. Brigham expects to continue to market interests in certain 3-D seismic projects or individual prospects during 2001 to provide incremental sources of capital for reinvestment in its drilling program, to limit its risk exposure and to improve its project economics.

3-D Seismic Technology

Brigham's strategy is to use 3-D seismic and other advanced technologies, including computer-aided exploration ("CAEX"), to systematically explore and develop domestic onshore oil and natural gas provinces. In general, 3-D seismic is the process of acquiring seismic data along multiple lines and grids. The primary advantage of 3-D seismic over 2-D seismic is that it provides information with respect to multiple horizontal and vertical points within a geologic formation instead of information on a single vertical line or multiple vertical lines within the formation. Acquiring larger amounts of data relating to a geologic formation allows a user to better correlate the data and, in some cases, to obtain a greater understanding and image of the formation. Although it is impossible to predict with certainty the specific configuration or composition of any underground geologic formation, the use of 3-D seismic data provides clearer and more accurate projected images of complex geologic formations, which can assist a user in evaluating whether to drill for oil and natural gas reserves. If a decision to drill is made, 3-D seismic data can also help in determining the optimal location to drill.

CAEX is the process of accumulating and analyzing the various seismic, production and other data obtained relating to a geographic area. In general, CAEX involves accumulating various 2-D and 3-D seismic data with respect to a potential drilling location, correlating that data with historical well control and production data from similar properties and analyzing the available data through computer programs and modeling techniques to project the likely geologic composition of a potential drilling location and potential locations of undiscovered oil and natural gas reserves. This process relies on a comparison of data with respect to the potential drilling location and historical data with respect to the density and sonic characteristics of different types of rock formations, hydrocarbons and other subsurface minerals, resulting in a projected three dimensional image of the subsurface. This modeling is performed through the use of advanced interactive computer workstations and various combinations of available computer programs that have been developed solely for this application.

Exploration and Operating Approach

Brigham has acquired 3-D seismic data covering 5,122 square miles (3.3 million acres) in over 20 geologic trends in seven basins and seven states. Through this activity, Brigham has developed expertise in the selection of geologic trends that are suitable for 3-D seismic exploration. Brigham uses experience that it gains within a trend to enhance the quality of subsequent projects in the same trend and other analogous trends, contributing to lower finding and development costs, compressed project cycle times and increased project rates of return.

Brigham typically acquires 3-D seismic data in and around existing producing fields where it can benefit from the imaging of producing analogs. These 3-D defined analogs, combined with Brigham's experience in drilling nearly 500 wells in its 3-D project areas, provide Brigham with a knowledge base to evaluate other potential geologic trends, 3-D seismic projects within trends and prospective 3-D delineated drilling locations. Brigham's knowledge base assists in identifying geologic trends where Brigham believes it can find and develop economic volumes of oil and natural gas.

Brigham has experience exploring with 3-D seismic in a wide range of reservoir types and geologic trapping styles, both stratigraphic and structural (including reefs, salt domes, channel sands, complex faulted and fractured reservoirs and pinchout plays). Occasionally, Brigham seeks to supplement its knowledge base with the best local geologic expertise available for a particular geologic trend. In addition, Brigham typically acquires digital data bases for integration on its CAEX workstations, including digital land grids, well information, log curves, production information, geologic studies, geologic top data bases and existing 2-D seismic data.

Brigham uses its knowledge base, local geological expertise and digital data bases integrated with 3-D seismic data to create maps of producing and potentially productive reservoirs. Brigham believes its 3-D generated maps are more accurate than previous reservoir maps (which generally were based on subsurface geological information and 2-D seismic surveys), enabling it to more precisely evaluate recoverable reserves and the economic feasibility of projects and drilling locations.

Brigham has acquired most of its 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, Brigham has participated in non-proprietary group shoots of 3-D seismic data (commonly referred to as "spec data") when it believes the expected full cycle project economics are justified. In most of its proprietary 3-D data acquisitions and alliances, Brigham has selected the sites of projects, primarily guided by its knowledge and experience in the core provinces it explores; established and monitored the seismic parameters of each project for which data was shot; and typically selected the equipment that was used. The acquisition of 3-D seismic data has generally been priced on the basis of the number of square miles shot.

Brigham's operations personnel (including management) includes five petroleum engineers that have reservoir and operations engineering experience primarily within Brigham's three core areas of operations. These engineers work closely with Brigham's explorationists and are integrally involved in all phases of the exploration and development process, including preparation of pre- and post-drill reserve estimates, analysis of full cycle risked drilling economics, well design and production management. Brigham conducts field operations for its operated oil and natural gas properties through third party contract personnel. In an effort to retain better control of its project timing, drilling and operational costs and production volumes, Brigham has significantly increased the percentage of the wells that it operates during the past several years. Brigham operated 55% of the gross and 82% of the net wells it participated in during 2000, as compared with 10% and 17%, respectively, of its wells drilled during 1996. As a result of its increased operational control in recent years, Brigham-operated wells constituted 73% of the PV10% value of its proved developed producing reserves at year-end 2000, as compared with only 8% at year-end 1996.

Technical Staff

Brigham's experienced technical staff (excluding management) includes five geophysicists, six geologists, four petroleum engineers, four computer applications specialists, four geophysical/geological/engineering technicians, three landmen and two lease and division order analysts. Brigham's geophysicists have different but complementary backgrounds, and their diversity of experience in varied geological and geophysical settings, combined with various technical specializations (from hardware and systems to software and seismic data processing), provide Brigham with valuable technical intellectual resources. Brigham's team of explorationists has over 210 years of exploration experience, or an average of more than 19 years per person, most of which was acquired at Brigham and various major and large independent oil companies. Brigham's team of technical specialists was assembled according to the expertise that these individuals have within producing basins where Brigham focuses its exploration and development activities. By integrating both geologic and geophysical expertise within its project teams, Brigham believes it possesses a competitive advantage in its exploration approach. Occasionally, Brigham will complement and leverage its exploration staff by

seeking out alliances or retainer relationships with geologists and other technical professionals who have extensive experience in a particular area of interest.

Oil and Natural Gas Marketing and Major Customers

Most of Brigham's oil and natural gas production is sold under price sensitive or spot market contracts. The revenues generated by Brigham's operations are highly dependent upon the prices of and demand for oil and natural gas. The price received by Brigham for its oil and natural gas production depends on numerous factors beyond Brigham's control, including seasonality, 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. Decreases in the prices of oil and natural gas could have an adverse effect on the carrying value of Brigham's proved reserves and its revenues, profitability and cash flow. Although Brigham is not currently experiencing any significant involuntary curtailment of its oil or natural gas production, market, economic and regulatory factors may in the future materially affect Brigham's ability to sell its oil or natural gas production. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations", "-- Risk Factors -- Volatility Of Oil And Gas Markets Affects Us; Oil And Natural Gas Prices Are Volatile" and "-- Risk Factors -- The Marketability Of Our Production Is Dependent On Facilities That We Typically Do Not Own Or Control." For the year ended December 31, 2000, sales to Highland Energy Company and Lantern Petroleum Corporation were approximately 36% and 20%, respectively, of Brigham's oil and natural gas revenues. Due to the availability of other markets and pipeline connections, Brigham does not believe that the loss of any single oil or natural gas customer would have a material adverse effect on its results of operations.

Competition

The oil and gas industry is highly competitive in all of its phases. Brigham encounters competition from other oil and gas companies in all areas of its operations, including the acquisition of seismic and leasing options and oil and natural gas leases on properties. Brigham's 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 its competitors are large, well established companies with substantially larger operating staffs and greater capital resources than Brigham. 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 Brigham's financial or human resources permit. Brigham's ability to acquire additional properties and to discover reserves in the future will be dependent upon its ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations -- Risk Factors -- We Face Significant Competition" and "-- Risk Factors -- We Have Substantial Capital Requirements."

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 new wells drilled by Brigham will be productive or that Brigham will recover all or any portion of its 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. Brigham's drilling operations may be curtailed, delayed or canceled as a result of numerous factors, many of which are beyond Brigham's control, including title problems, weather conditions, delays by project participants, compliance with governmental requirements and shortages or delays in the delivery of equipment and services. Brigham's future drilling activities may not be successful and, if unsuccessful, such failure may have a material adverse effect on its business, financial condition or results of operations. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations -- Risk Factors -- Exploratory Drilling Is A Speculative Activity Involving Numerous Risks And Uncertain Costs; We Are Dependent On Exploratory Drilling Activities." In addition, use of 3-D seismic technology requires greater pre-drilling expenditures than traditional drilling strategies. Although Brigham believes that its 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 Brigham's business, financial condition or results of operations.

Brigham's 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 properties of Brigham and others. Brigham maintains insurance against some but not all of the risks described above. In particular, the insurance maintained by Brigham does not cover claims relating to failure of title to oil and natural gas leases, trespass during 3-D survey acquisition or surface change attributable to seismic operations, business interruption or loss of revenues due to well failure. Furthermore, in certain circumstances in which insurance is available, Brigham 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 Brigham's business, financial condition and results of operations.

Employees

On March 20, 2001, Brigham had 49 full-time employees. None is represented by any labor union. Brigham believes its relations with its employees are good. In addition, Brigham relies on several regional consulting service companies to provide field landmen to support Brigham on a project-by-project basis. One of these companies, Brigham Land Management, is owned by Vincent M. Brigham, who is the brother of Ben M. Brigham, the Company's Chief Executive Officer, President and Chairman of the Board.

Facilities

Brigham's principal executive offices are located in Austin, Texas, where it leases approximately 34,330 square feet of office space at 6300 Bridge Point Parkway, Building 2, Suite 500, Austin, Texas 78730. In an effort to reduce corporate overhead expenses, Brigham has subleased approximately 5,300 square feet of excess office space at its principal executive offices to a third party for a two-year term beginning in November 1999.

Title to Properties

Brigham believes it has satisfactory title, in all material respects, to substantially all of its producing properties in accordance with standards generally accepted in the oil and gas industry. Brigham's properties are subject to royalty interests, standard liens incident to operating agreements, liens for current taxes and other inchoate burdens which Brigham believes do not materially interfere with the use of or affect the value of such properties. Brigham's Senior Credit Facility (as defined) is secured by a first lien against substantially all of Brigham's oil and natural gas properties and other tangible assets, and Brigham's Subordinated Notes Facility (as defined) is secured by a second lien against all collateral pledged by Brigham as security under its Senior Credit Facility. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

Governmental Regulation

Brigham's oil and natural gas exploration, production and marketing activities are subject to extensive laws, rules and regulations promulgated by federal and state legislatures and agencies. Failure to comply with such laws, rules and regulations can result in substantial penalties. The legislative and regulatory burden on the oil and gas industry increases Brigham's cost of doing business and affects its profitability. Although Brigham believes it is in substantial compliance with all applicable laws and regulations, Brigham is unable to predict the future cost or impact of complying with such laws and regulations because they are frequently amended, interpreted and reinterpreted.

The State of Texas and many 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

Brigham's operations and properties are, like the oil and 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 the acquisition of a permit or other authorization before construction or drilling commences and for certain other activities; limit or prohibit seismic acquisition, construction, drilling and other activities on certain lands lying within wilderness and other protected areas; and impose substantial liabilities for pollution resulting from Brigham's operations. The permits required for various of Brigham's 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 or injunction, or both. In the opinion of management, Brigham is in substantial compliance with current applicable environmental laws and regulations, and Brigham has 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 Brigham, as well as the oil and gas industry in general. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA") and comparable state statutes impose strict and arguably joint and several liability 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 Brigham's 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 the Company, 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 Brigham. 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. With respect to certain of its operations, Brigham is required to maintain such permits or meet general permit requirements. The Environmental Protection Agency ("EPA") has in place regulations concerning discharges of storm water runoff. This program requires covered facilities to obtain individual permits, participate in a group or seek coverage under an EPA general permit. Brigham believes that it 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 Brigham.

Brigham has acquired leasehold interests in numerous properties that for many years have produced oil and natural gas. Although Brigham believes that the previous owners of these interests have used operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties. In addition, some of Brigham's properties are operated by third parties over whom it has little control. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations -- Other

Matters" and "-- Risk Factors -- We Are Subject To Various Governmental Regulations And Environmental Risks."

ITEM 2. PROPERTIES

Primary Exploration Provinces

Brigham focuses its 3-D seismic exploration efforts in oil and natural gas producing provinces where it believes 3-D technology may be effectively applied to generate relatively large potential reserve volumes per well and per field, high potential production rates and multiple producing objectives. Brigham's exploration activities are concentrated primarily in three core provinces: the Anadarko Basin of western Oklahoma and the Texas Panhandle; the onshore Texas Gulf Coast; and West Texas. During the past four years, Brigham has concentrated the majority of its 3-D seismic and drilling activities on natural gas projects in the Anadarko Basin and Gulf Coast provinces primarily due to the higher expected rates of return provided by these opportunities relative to its more mature West Texas oil projects. However, in response to strong crude oil prices in late 2000 and to date in 2001, Brigham has recently begun to selectively drill certain of its higher grade, 3-D delineated West Texas prospects.

In 1997 and 1998, Brigham made significant investments in the acquisition of 3-D seismic and prospective acreage in its Anadarko Basin and Gulf Coast provinces. Through these investments, Brigham believes it has assembled an inventory of potential drilling locations that will support a multi-year drilling program, thereby providing attractive opportunities for long-term growth. From inception in 1990 through 2000, Brigham achieved net drilling costs of \$0.75 per Mcfe added through its 3-D seismic exploration efforts. In addition, the vast majority of Brigham's estimated potential drilling locations are in its currently most active Anadarko Basin and Gulf Coast provinces where Brigham has achieved inception-to-date average net drilling costs of \$0.53 and \$0.91 per Mcfe, respectively.

Continuing its strategic focus implemented during 1999 and 2000, Brigham intends to direct substantially all of its efforts and available capital resources in 2001 to the drilling and monetization of the highest grade prospects within its over 5,000 square mile inventory of 3-D seismic data. Employing this emphasis during the past two years, Brigham achieved average drilling and all-in finding and development costs of \$0.62 per Mcfe and \$0.85 per Mcfe, respectively, in 1999 - 2000.

Brigham's planned 2001 exploration and development capital expenditure budget is estimated to be approximately \$26 million, which includes \$22 million to drill 25 planned wells with an average working interest of approximately 40%. Brigham's planned 2001 drilling program represents a balanced blend of capital investments consisting of both development projects to recent discoveries and high potential exploration prospects. Approximately 66% of budgeted drilling expenditures are allocated to development activities with the remaining 34% targeted for exploratory drilling of its highest-grade prospects. In addition, over 80% of Brigham's budgeted drilling expenditures are focused in five project areas in the Springer and Hunton trends of the Anadarko Basin and the Vicksburg and Frio trends of the Texas Gulf Coast. Each of these five 3-D projects are in areas that Brigham has experienced its most significant recent exploration and development drilling successes. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations -- Liquidity and Capital Resources."

Brigham's actual capital expenditures in 2001 may differ from the estimates discussed herein based upon cash flow and capital availability during the year. There can be no assurance that any potential drilling locations identified by Brigham will be drilled at all or within the expected time frame. The final determination with respect to the drilling of any well, including those currently budgeted, will depend on a number of factors, including:

- the results of exploration and development efforts and the continuing review and analysis of the seismic data;

- the availability of sufficient capital resources by Brigham and other participants for drilling prospects;
- economic and industry conditions at the time of drilling, including prevailing and anticipated prices for oil and natural gas and the availability of drilling rigs and crews;
- Brigham's future financial results; and
- the availability of leases on reasonable terms and permitting for the potential drilling location.

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

Anadarko Basin

The Anadarko Basin is a prolific natural gas province that Brigham believes offers a combination of lower risk exploration and development opportunities in shallower horizons and deeper, higher potential objectives that have been relatively under explored. This province has produced in excess of 90 Tcfe to date from numerous, historically elusive stratigraphic targets, such as the Red Fork, Upper Morrow and Springer channel sands, as well as from deeper, higher potential structural objectives, such the Lower Morrow sandstones and the Hunton and Arbuckle carbonates. In some cases, these objectives have produced in excess of 50 Bcf of natural gas from a single well at rates of up to 30 MMcf of natural gas per day. In addition, drilling economics in the Anadarko Basin are enhanced by the multi-pay nature of many of the prospects in this province, with secondary or tertiary targets serving as either incremental value or bailout potential relative to the primary target zone.

Each of the stratigraphic and structural objectives in the Anadarko Basin can provide excellent targets for 3-D seismic imaging. Brigham has assembled an extensive digital data base in this province, including geologic studies, basin wide geologic tops, production data, well data, geographic data and over 8,400 miles of 2-D seismic data. Brigham's explorationists integrate this data with their extensive expertise and knowledge base to generate 3-D projects in the Anadarko Basin.

As of December 31, 2000, Brigham had acquired 2,062 square miles (1.3 million acres) of 3-D seismic data in the Anadarko Basin. Through its drilling efforts in this region from 1994 through 2000, Brigham had completed 92 wells in 119 attempts (77% completion rate) in the Anadarko Basin and had found cumulative net proved reserves of 79 Bcfe at an average net drilling cost of \$0.53 per Mcfe. In its Anadarko Basin drilling program in 1999 and 2000, Brigham completed 21 wells in 24 attempts (88% completion rate) with an average working interest of 42% that contributed to the addition of 32 net Bcfe of proved reserves (including revisions to previous estimates) at an average net drilling cost of \$0.30 per Mcfe.

Brigham intends to focus the majority of its exploration and development drilling expenditures in its Anadarko Basin province in the following key project areas during 2001:

Huskie and Boilermaker Projects

Brigham's Huskie and Boilermaker Projects consist of 103 and 96 square miles, respectively, of continuous 3-D seismic data covering approximately 127,000 acres in Blaine County, Oklahoma. These projects target stratigraphic fluvial sand channels in the Springer-aged Old Woman and Britt intervals. Brigham initiated acquisition of data in its Huskie Project in 1996 where it retained a 37.5% working interest and, based upon the prospect density and reserve potential interpreted from this initial data set, Brigham subsequently acquired data in its adjacent Boilermaker Project in 1998 where it retained a 100% working interest.

Brigham completed three Springer wells in three attempts in its Huskie Project during 2000. The first of these Springer channel sand tests was drilled to a depth of approximately 10,300 feet and encountered 41 feet of net pay. This discovery well began producing in May 2000 at a pipeline-curtailed daily rate of 3.5 MMcf of natural gas and 350 barrels

of condensate, or 3.1 MMcf net to Brigham's revenue interest. Upon completion of a pipeline expansion in December 2000, daily production from this well was increased to 6.5 MMcf of natural gas and 250 barrels of condensate, or 3.8 MMcf net to Brigham. Its most recent discovery in this project was drilled to a total depth of approximately 9,750 feet in December 2000 to test an analogous 3-D delineated Springer channel objective. Brigham completed this well in February 2001 at an initial test rate of 7.4 MMcf of natural gas and 90 barrels of condensate per day, or 1.6 MMcf per day net to Brigham's 20% revenue interest. Brigham operates this discovery and began producing the well in mid-March 2001 at a pipeline-curtailed rate of approximately 2.2 MMcf of natural gas and 75 barrels of oil per day, or 0.5 MMcf net to Brigham.

Based on the success of its 2000 drilling activity in this project area, Brigham plans to drill four to six Springer channel tests in its Huskie Project in 2001. These wells target similar objectives as its three 2000 producers, and Brigham expects to retain an working interest of approximately 50% in these planned wells.

Wildcat and Panther Projects

Brigham's Wildcat and Panther Projects consist of 47 and 99 square miles, respectively, of continuous 3-D seismic data covering approximately 93,440 acres in the southern portion of the Texas Panhandle in Wheeler County, Texas and Beckham County, Oklahoma. The primary exploration targets within these projects are high potential, structural features at depths ranging from 7,500 to 25,000 feet. Brigham initiated acquisition of data in its Wildcat Project in 1997 where it retained a 37.5% working interest. Based upon the interpretation of this initial data set, Brigham subsequently acquired data in its adjacent Panther Project in 1998 where it retained a 100% working interest.

In July 2000, Brigham spud a high potential Hunton test (64% working interest) that offsets a currently producing Hunton well that has produced over 15 Bcfe to date in its Wildcat Project. Drilled to a total depth of over 25,000 feet, Brigham completed the well in the targeted Hunton formation in late December 2000. The well encountered approximately 1,200 feet of gross pay and 340 feet of measured depth net pay (240 feet of calculated true vertical net pay) in three Hunton intervals. The well began producing to sales from one Hunton interval in early January 2001 at rates of approximately 9.5 MMcf of natural gas and 90 barrels of condensate per day, or 5.1 MMcf per day net to Brigham's 51% revenue interest. Current plans include stimulation of the two remaining Hunton pay intervals in the discovery well, and the drilling of at least one development well during 2001. Brigham has booked estimated proved reserves of approximately 21 gross Bcfe (or 10.7 net Bcfe) attributable to this Hunton producer at December 31, 2000. While ultimate recoverable reserves from this field discovery will be determined by the productivity of this initial well and future offset locations, Brigham believes this Hunton field could ultimately produce up to 250 Bcfe of gross unrisks reserves. In addition to this discovery, Brigham has also assembled a significant acreage position along trend and may drill another high potential exploratory Hunton test in early 2002.

Bearcat Project

Brigham's Bearcat Project consists of approximately 59 square miles of 3-D seismic data covering approximately 37,760 acres in the prolific Carter-Knox anticline in Grady County, Oklahoma. This project targets 3-D seismic amplitude-related shallow Pennsylvanian-aged channel sands and deep marine bar sands in the Springer section.

During its 2000 drilling program, Brigham participated in three wells that have confirmed the discovery of a potentially significant Springer Bar field that is estimated to be approximately nine miles long and two miles wide. The initial exploratory test of this 3-D delineated Springer Bar objective, the Nix #1-20 (20% working interest), encountered approximately 90 feet of Springer-aged sand that confirmed Brigham's seismic interpretation of this feature. Subsequent to this initial discovery, Brigham participated in two development wells in this new field. The Pitchford #1 (32% working interest) reached a total depth of 15,140 feet and logged approximately 31 feet of pay (greater than 8% density porosity) in the targeted Britt section with significant porosity improvement relative to the Nix #1-20. After fracture stimulation of this Britt interval, the well began producing to sales at a rate of approximately 2.2 MMcf of natural gas and 140 barrels of condensate per day, or approximately 3 MMcf per day, in December 2000. The second development well, the McCasland Farms #1 (23% working interest) was spud in late October 2000 and is currently being completed and fracture stimulated prior to commencement of production expected by the end of March 2001. This well logged 32 feet of

porosity density greater than 8%, which is comparable to that logged in the producing Pitchford #1 well.

Brigham currently owns over 2,500 net acres in nine sections over this Springer Bar feature, and anticipates participating in up to ten additional wells to fully develop the field. In its 2001 drilling program, Brigham plans to participate in the drilling of up to five development wells in this Springer Bar field with working interests generally ranging from 20% to 25%.

Texas Gulf Coast

The onshore Texas 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. Brigham was attracted to the Gulf Coast province because of the opportunity to apply its established 3-D seismic exploration approach and its exploration staff's extensive Gulf Coast experience to a prolific, structurally complex province with the potential to discover significant natural gas reserves and high rate production. Brigham has assembled a digital data base including geographical, production, geophysical and geological information that it evaluates on CAEX workstations. Brigham's team of explorationists has assembled projects in the Expanded Wilcox and Expanded Vicksburg trends in South Texas, and the Miocene and Upper, Middle, and Lower Frio trends of the mid-to-southern regions of the Texas Gulf Coast, each of which are active 3-D seismic exploration trends. The majority of Brigham's recent activity in this province has been focused in the Expanded Vicksburg and Frio trends.

A portion of Brigham's 3-D seismic data acquisition in the Gulf Coast has been accomplished through participation in certain non-proprietary, or speculative, seismic programs. By converting certain of Brigham's proprietary seismic projects in core exploration areas to speculative data, Brigham was able to leverage these proprietary projects for access to substantially larger non-proprietary speculative data for minimal or no additional cost. While increasing its exposure to competition in speculative seismic programs, Brigham believes this 3-D seismic acquisition strategy in the Gulf Coast, in certain circumstances, can accelerate the addition of attractive potential drilling locations in targeted trends at costs that are considerably less than those associated with proprietary 3-D seismic programs, thereby enhancing expected project rates of return.

As of December 31, 2000, Brigham had acquired 1,096 square miles (701,440 acres) of 3-D seismic data in its Texas Gulf Coast province. Through its drilling efforts in this region from 1996 through 2000, Brigham had completed 46 wells in 60 attempts (77% completion rate) in the Gulf Coast and had discovered cumulative net proved reserves of approximately 37 Bcfe at an average net drilling cost of \$0.91 per Mcfe. In its Gulf Coast drilling program in 1999 and 2000, Brigham completed 21 wells in 28 attempts (75% completion rate) with an average working interest of 28% that contributed to the addition of approximately 13 net Bcfe of proved reserves (including revisions to previous estimates) at an average net drilling cost of \$1.49 per Mcfe.

Brigham intends to focus the majority of its Texas Gulf Coast province exploration and development drilling expenditures in the following key project areas during 2001:

Diablo Project

Brigham's Diablo Project covers 57 square miles in Brooks County, Texas, and targets shallow Frio and deep Vicksburg producing horizons. Brigham is involved in a joint venture with a major integrated oil company in its Diablo Project. The project participants jointly control a significant acreage block and are actively exploring and developing for potential pay below 10,000 feet in the Vicksburg formation in this project area. Brigham has retained a 34% working interest in this joint exploration project in which the project participants control approximately 10,000 gross and net acres of leasehold. However, in prospective zones above 10,000 feet, primarily the Frio, Brigham has retained a 100% working interest in its original 4,000 acre lease block.

In the fourth quarter of 1999, Brigham confirmed a major Lower Vicksburg field discovery, the Home Run Field, in the Diablo Project with the completion of the Brigham-operated Palmer State #2 well. The Palmer State #2 encountered productive reservoirs in four Lower Vicksburg intervals with 210 feet of potential pay. After completion of successive operations to fracture stimulate each of these intervals during January and February 2000, the well was successfully commingled to produce simultaneously from all four Lower Vicksburg intervals. The Palmer State #2 began flowing to sales as a commingled producer in late February 2000 at average daily production rates of 10.1 MMcf of natural gas and 650 barrels of condensate, or approximately 4 MMcfe in total net to Brigham's 29% revenue interest. In mid-March 2001, this well was producing 3.1 MMcfe per day, or 0.9 MMcfe net to Brigham's revenue interest.

Brigham spud three development wells in the Home Run Field during 2000. The first development well, the Palmer State #3, began producing in early August 2000 at an initial rate of 12.3 MMcf of natural gas and 450 barrels of condensate per day, or 4.4 MMcfe net to Brigham's 29% revenue interest. In late October 2000, Brigham spud the second development well in the Home Run Field, the Palmer State #4, which is an updip offset to the Palmer State #2 field confirmation well. The Palmer State #4 is currently being completed and fracture stimulated in the target Lower Vicksburg objectives and is expected to be producing through commingled completions by the end of March 2001. The third Home Run field development well, the D.J. Sullivan #C-25, was spud in late December 2000 and is currently being completed with expected commingled production to sales by April 2001. Brigham retains net revenue interests ranging from 26% to 29% in each of these three Home Run Field development wells.

Brigham's 3-D interpretative mapping indicates that the Home Run Field reservoirs have over 500 feet of relief and cover approximately 1,100 acres with estimated potential gross reserves ranging from a minimum of 80 Bcfe to over 200 Bcfe (or 23 Bcfe to 58 Bcfe net). Brigham had 16.5 net Bcfe of estimated proved reserves attributable to the Home Run Field as of December 31, 2000. In addition to the expected production volume additions from the Palmer State #4 and D.J. Sullivan #C-25 wells, Brigham's planned drilling program includes two additional development wells to be drilled in the Home Run Field during 2001.

The 1,100 acre Home Run Field is located upthrown from two large, untested 3-D delineated Vicksburg structures (Mariposa and Floyd) in adjacent fault blocks that cover approximately 1,200 acres. Brigham currently plans to spud an exploratory test of the estimated 1,000 acre Mariposa fault block in the second quarter of 2001. This 3-D delineated Vicksburg structure is located beneath the shallower Mariposa Field that has produced in excess of 187 Bcf of natural gas from the Frio. The estimated 200 acre Floyd fault block is an apparent four-way Lower Vicksburg closure that Brigham plans to test in early 2002. Brigham believes that its Home Run Field discovery and subsequent development efforts to date have significantly enhanced the prospectiveness of each of these large structural closures. Additional exploratory fault blocks in this project area are currently being interpreted and may be tested in 2002 and beyond.

Hawkins Ranch and Millenium Projects

Brigham's Hawkins Ranch and Millenium Projects consist of 344 square miles of contiguous non-proprietary 3-D seismic data in the prolific Miocene/Frio trend in Matagorda County, Texas. Identified prospects in these project areas target potential in the shallow, nonpressured Frio sands as well as the deeper, pressured Frio sands. Operators have been actively leasing and drilling within this acreage during the past three years. This activity has resulted in the completion of 24 wells in 39 attempts, including the discovery of a 3-D delineated field that is estimated to contain gross reserves of approximately 40 Bcfe from three wells that have produced at rates in excess of 30 MMcf of natural gas per day per well. Sustaining these high production rates, these three wells have produced in excess of 37 Bcfe in less than eighteen months.

During the fourth quarter of 2000, Brigham participated in the drilling of a 3-D delineated Frio bright spot discovery in its Millenium Project. This well was completed in the targeted Frio objective in late December 2000 at daily rates of approximately 10 MMcf of natural gas and 200 barrels of condensate per day, or 2.1 MMcfe net to Brigham's 18.75% revenue interest. Based on the success of this recent discovery, Brigham spud an offsetting Frio bright spot test in late February 2001. This well was completed in early March 2001 and began producing at a rate of 17.5 MMcf of natural gas and 290 barrels of condensate per day, or 4.4 MMcfe net to Brigham's 23% net revenue interest. In addition to these recent discoveries, Brigham spud an additional Frio bright spot test in March 2001 in which it retained a 34% working interest.

Including the recently spud offset Frio test, Brigham's 2001 drilling program includes three 3-D seismic amplitude-supported prospects in its Hawkins Ranch and Millenium Projects that target combined gross unrisks reserve potential of 18 Bcfe. Brigham expects to retain an average working interest of approximately 40% in these three planned Frio wells.

West Texas

Brigham's drilling activity in its West Texas province has been focused primarily in the Horseshoe Atoll, the Midland Basin and the Eastern Shelf of the Permian Basin and in the Hardeman Basin. In response to reduced market prices for oil and comparatively higher potential natural gas projects in its Anadarko Basin and Gulf Coast provinces, Brigham substantially reduced its 3-D seismic acquisition and drilling activities in West Texas during 1998 and 1999. Based on improved oil prices during 2000 and in early 2001, Brigham has begun to selectively drill certain of its highest grade oil prospects in its West Texas 3-D seismic projects. To date, Brigham has been able to participate in the drilling of many of these wells by selling a portion of its working interest to industry participants on a promoted basis in which the participants pay a disproportionate share of the drilling costs.

As of December 31, 2000, Brigham had acquired 1,689 square miles (1.1 million acres) in the West Texas region. Through its drilling efforts in this region from 1990 through 2000, Brigham had completed 186 wells in 300 attempts (62% completion rate) in its West Texas province with an average working interest of 24% and had found cumulative net proved reserves of 23 Bcfe at an average net drilling cost of \$1.23 per Mcfe. In its substantially reduced drilling activity in this province during 1999 and 2000, Brigham completed one well in two attempts (50% completion rate) with an average working interest of 84% that contributed to the addition of 2.9 net Bcfe of proved reserves (including revisions to previous estimates) at an average net drilling cost of \$0.14 per Mcfe. In December 2000, Brigham spud a Canyon Reef test that was drilled to a total depth of 9,400 feet. The well was completed as a successful oil producer in February 2001 after logging over 90 feet of oil pay. In early March 2001, this well was producing 200 barrels of oil per day, or approximately 140 barrels per day net to Brigham's 71% revenue interest.

During 2001, Brigham plans to drill three to five wells in its West Texas 3-D project areas. In January 2001, Brigham spud a Fusselman test in its West Texas province in which it retained a 55% working interest. This well logged nine feet of pay and is expected to be completed as a producer by the end of March 2001.

Oil and Natural Gas Reserves

Brigham's estimated total net proved reserves of oil and natural gas as of December 31, 1998, 1999 and 2000 and the present values attributable to these reserves as of those dates were as follows:

	<u>As of December 31,</u>		
	<u>1998</u>	<u>1999</u>	<u>2000</u>
Estimated net proved reserves:			
Natural gas (MMcf)	71,166	65,457	78,167
Oil (MBbls)	4,433	3,027	2,870
Natural gas equivalent (MMcfe)	97,764	83,618	95,388
Proved developed reserves as a percentage of proved reserves	57%	48%	52%
Present Value of Future Net Revenues (in thousands)	\$ 81,741	\$ 114,466	\$ 497,666
Standardized Measure (in thousands)	\$ 81,649	\$ 113,546	\$ 359,228

The reserve estimates reflected above were prepared by Cawley, Gillespie & Associates, Inc. ("Cawley Gillespie"), Brigham's petroleum consultants, and are part of reports on Brigham's oil and natural gas properties prepared by Cawley Gillespie. The base sales prices for Brigham's reserves were \$2.12 per Mcf for natural gas and \$9.50 per Bbl for oil as of December 31, 1998, \$2.35 per Mcf for natural gas and \$22.75 per Bbl for oil as of December 31, 1999, and \$10.42 per Mcf for natural gas and \$26.83 per Bbl for oil as of December 31, 2000. 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

Brigham's reserves at these dates.

In accordance with applicable requirements of the SEC, estimates of Brigham's 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 proved reserves and future net revenues therefrom 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 Brigham's control. The reserve data set forth in this Form 10-K represent 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 Brigham, 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. Brigham's estimated proved reserves have not been filed with or included in reports to any federal agency. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations -- Risk Factors -- We Are Subject To Uncertainties In Reserve Estimates And Future Net Cash Flows."

Estimates with respect to 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.

Drilling Activities

Brigham drilled, or participated in the drilling of, the following number of wells during the periods indicated:

	Year Ended December 31,					
	1998		1999		2000 (1)	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells (2):						
Natural gas	30	15.6	8	3.4	6	1.9
Oil	7	2.5	2	0.1	3	0.9
Non-productive	<u>17</u>	<u>8.0</u>	<u>7</u>	<u>2.4</u>	<u>2</u>	<u>1.0</u>
Total.....	<u>54</u>	<u>26.1</u>	<u>17</u>	<u>5.9</u>	<u>11</u>	<u>3.8</u>
Development Wells (3):						
Natural gas	10	6.6	8	2.3	14	5.7
Oil	3	1.5	1	0.5	1	0.7
Non-productive	<u>5</u>	<u>3.4</u>	<u>1</u>	<u>0.6</u>	<u>1</u>	<u>0.8</u>
Total.....	<u>18</u>	<u>11.5</u>	<u>10</u>	<u>3.4</u>	<u>16</u>	<u>7.2</u>

- (1) Excludes one gross (1.0 net) exploratory well that was temporarily abandoned during drilling due to operational difficulties encountered prior to reaching total depth, and one gross (0.1 net) development well that was in the process of drilling at March 20, 2001. Brigham plans to re-enter the temporarily abandoned well to test the target natural gas objective during 2001.
- (2) From January 1, 2001 through March 20, 2001, Brigham drilled, or participated in the drilling of, five gross (2.4 net) exploratory wells, of which two gross (1.3 net) were completed as oil wells, two gross (0.8 net) were non-productive, and one gross (0.3 net) was in the process of drilling at March 20, 2001.
- (3) From January 1, 2001 through March 20, 2001, Brigham drilled, or participated in the drilling of, five gross (1.9 net) development wells, of which one gross (0.3 net) was completed as a natural gas well, one gross (0.04 net) was non-productive, and three gross (1.5 net) were in the process of drilling at March 20, 2001.

Brigham does not own any drilling rigs, and the majority of its drilling activities have been conducted by industry participant operators or independent contractors under standard drilling contracts. Consistent with its business strategy, Brigham has continued to retain operations of an increasing number of the wells it drills. Brigham operated 55% of the gross and 82% of the net wells it participated in during 2000.

Productive Wells and Acreage

Productive Wells

The following table sets forth Brigham's ownership interest as of December 31, 2000 in productive oil and natural gas wells in the areas indicated.

	Natural Gas		Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
Province:						
Anadarko Basin	63	21.3	10	2.8	73	24.1
Texas Gulf Coast	23	7.9	12	2.0	35	9.9
West Texas	12	1.7	76	22.4	88	24.1
Other	--	--	<u>2</u>	<u>0.7</u>	<u>2</u>	<u>0.7</u>
Total	<u>98</u>	<u>30.9</u>	<u>100</u>	<u>27.9</u>	<u>198</u>	<u>58.8</u>

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, none 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 in which Brigham held a leasehold, mineral or other interest at December 31, 2000:

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Province:						
Anadarko Basin	29,387	11,269	55,601	36,850	84,988	48,119
Gulf Coast.....	2,484	1,050	24,335	13,925	26,819	14,975
West Texas	6,089	1,784	13,372	4,735	19,461	6,519
Other	<u>480</u>	<u>148</u>	<u>7,350</u>	<u>2,576</u>	<u>7,830</u>	<u>2,724</u>
Total	<u>38,440</u>	<u>14,251</u>	<u>100,658</u>	<u>58,086</u>	<u>139,098</u>	<u>72,337</u>

All the leases for the undeveloped acreage summarized in the preceding table will expire at the end of their respective primary terms unless the existing leases are renewed, production has been obtained from the acreage subject to the lease prior to that date, or some other "savings clause" is implicated. The following table sets forth the minimum remaining terms of leases for the gross and net undeveloped acreage:

	Acres Expiring	
	Gross	Net
Twelve Months Ending:		
December 31, 2001	52,860	31,645
December 31, 2002.....	10,831	5,366
December 31, 2003.....	3,534	1,689
Thereafter.....	<u>33,433</u>	<u>19,386</u>
Total	<u>100,658</u>	<u>58,086</u>

In addition, Brigham had lease options as of December 31, 2000 to acquire an additional 622 gross and net acres, all of which expire in April 2001.

Volumes, Prices and Production Costs

The following table sets forth the production volumes, average prices received and average production costs associated with Brigham's sale of oil and natural gas for the periods indicated.

	<u>Year Ended December 31,</u>		
	<u>1998</u>	<u>1999</u>	<u>2000</u>
Production:			
Natural gas (MMcf).....	4,269	4,197	4,431
Oil (MBbls).....	396	346	362
Natural gas equivalent (MMcfe).....	6,644	6,270	6,600
Average sales price:			
Natural gas (per Mcf).....	\$ 2.04	\$ 2.11	\$ 1.94
Oil (per Bbl).....	\$ 12.85	\$ 17.79	\$ 29.17
Average production costs:			
Lease operating expenses (per Mcfe).....	\$ 0.33	\$ 0.36	\$ 0.32
Production taxes (per Mcfe).....	\$ 0.13	\$ 0.15	\$ 0.27

Costs Incurred

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

	<u>Year Ended December 31,</u>		
	<u>1998</u>	<u>1999⁽¹⁾</u>	<u>2000⁽²⁾</u>
Exploration.....	\$ 68,214	\$ 19,224	\$ 14,238
Property acquisition.....	16,245	3,462	2,540
Development.....	10,475	4,632	12,555
Proceeds from participants.....	<u>(10,502)</u>	<u>(2,439)</u>	<u>(40)</u>
Costs incurred	<u>\$ 84,432</u>	<u>\$ 24,879</u>	<u>\$ 29,293</u>

(1) Excludes \$27.1 million of proceeds from the sale of interests in properties, projects and prospects in 1999.

(2) Excludes \$3.9 million of proceeds from the sale of interests in properties, projects and prospects in 2000.

Costs incurred represent amounts incurred by Brigham for exploration, property acquisition and development activities. Periodically, Brigham will receive reimbursement of certain costs from participants in its projects subsequent to project initiation in return for an interest in the project. These payments are described as "Proceeds from participants" in the table above.

ITEM 3. LEGAL PROCEEDINGS

Brigham is not a party to any material legal proceedings.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITYHOLDERS

No matter was submitted to a vote of Brigham's securityholders during the fourth quarter of 2000.

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 table sets forth certain information concerning Brigham's executive officers as of March 20, 2001:

<u>Name</u>	<u>Age</u>	<u>Position</u>
Ben M. Brigham	41	Chief Executive Officer, President and Chairman
Curtis F. Harrell	37	Executive Vice President, Chief Financial Officer and Director
David T. Brigham	40	Senior Vice President – Land and Administration, Corporate Secretary
A. Lance Langford	38	Senior Vice President – Operations
Jeffery E. Larson	42	Senior Vice President – Exploration
Karen E. Lynch	39	Vice President – Legal and General Counsel
Christopher A. Phelps	30	Vice President – Finance and Strategic Planning

Set forth below is a description of the backgrounds of Brigham's executive officers.

Ben M. "Bud" Brigham has served as Chief Executive Officer, President and Chairman of the Board since founding the Company 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, a provider of 3-D seismic services, after earning his B.S. in Geophysics from the University of Texas. Mr. Brigham is the husband of Anne L. Brigham, Director, and the brother of David T. Brigham, Vice President -- Land and Administration and Corporate Secretary.

Curtis F. Harrell has served as Chief Financial Officer and Director of Brigham since August 1999, and as Executive Vice President since March 2001. From 1997 to August 1999, he was Executive Vice President and Partner at R. Chaney & Company, Inc., an equity investment firm focused on the energy industry, where he managed the firm's investment origination efforts in the U.S., focusing on investments in corporate equity securities of energy companies in the exploration and production and oilfield service industry segments. From 1995 to 1997, Mr. Harrell was a Director of Domestic Corporate Finance for Enron Capital & Trade Resources, Inc., where he was responsible for initiating and executing a variety of debt and equity financing transactions for independent exploration and production companies. Before joining Enron Capital & Trade Resources, Mr. Harrell spent eight years working in corporate finance and reservoir engineering positions for two public independent exploration and production companies, Kelley Oil & Gas Corporation and Pacific Enterprises Oil Company, Inc. He has a B.S. in Petroleum Engineering from the University of Texas at Austin and an M.B.A. from Southern Methodist University.

David T. Brigham joined the Company in 1992 and has served as Senior Vice President -- Land and Administration and Corporate Secretary since March 2001. Mr. Brigham served as Vice President -- Land and Administration and Corporate Secretary from February 1998 to March 2001, and as Vice President -- Land and Legal of the Company from 1994 until February 1998. 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 Brigham as Manager of Operations in 1995 and has served as Vice President -- Operations from January 1997 to March 2001, and as Senior Vice President -- Operations since March 2001. 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 Brigham in 1997 and has served as Vice President -- Exploration from August 1999 to March 2001, and as Senior Vice President -- Exploration since March 2001. Mr. Larson joined Brigham in October 1997 as Gulf Coast Exploration Manager in its Houston office where he co-managed Brigham's expansion into the onshore Gulf Coast province through the initiation and assemblage of 3-D seismic projects and drilling opportunities. In November 1998, Mr. Larson relocated to Brigham's corporate office in Austin where he assumed an expanded role in directing Brigham's exploration activities in the Anadarko Basin, in addition to the further advancement of its Gulf Coast activities. Prior to joining Brigham, 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 for seven years in various roles of increasing responsibility within its exploration department. Prior to Burlington, Mr. Larson spent five years at Exxon as a Production Geologist and Research Scientist. He has a B.S. in Earth Science from St. Cloud State University in Minnesota and a M.S. in Geology from the University of Montana.

Karen E. Lynch joined Brigham in October 1997 as General Counsel and has served as Vice President -- Legal and General Counsel since February 1998. Prior to joining Brigham, Ms. Lynch was a shareholder in the Dallas-based law firm of Thompson & Knight, P.C., where she practiced in the energy area since joining the firm in 1987. Ms. Lynch holds a B.B.A. in Petroleum Land Management from the University of Texas and a J.D. from the University of Oklahoma.

Christopher A. Phelps joined Brigham as Manager of Finance and Investor Relations in January 1998 and has served as Vice President -- Finance and Strategic Planning since August 1999. Prior to joining Brigham, Mr. Phelps was a Vice President in the Investment Banking Department of Bear, Stearns & Co. Inc., a major international securities brokerage and investment banking firm, where he spent over five years executing a variety of capital raising and mergers and acquisition transactions principally for independent exploration and production companies. He holds a B.B.A. in Finance from the University of Texas at Austin.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Brigham's common stock has been publicly traded on The Nasdaq Stock MarketSM under the symbol "BEXP" since Brigham's initial public offering effective May 8, 1997. The following table summarizes the high and low last reported sales prices of Brigham's common stock on Nasdaq for each quarterly period during the past two fiscal years:

	1999		2000	
	High	Low	High	Low
First Quarter	\$6.00	\$2.75	\$2.88	\$1.47
Second Quarter.....	\$3.25	\$0.88	\$2.88	\$1.88
Third Quarter.....	\$3.31	\$1.94	\$3.50	\$2.00
Fourth Quarter.....	\$2.72	\$1.00	\$6.00	\$2.00

The closing market price of Brigham's common stock on March 20, 2001 was \$4.00 per share. As of March 20, 2001, there were an estimated 118 record owners of Brigham's common stock.

No dividends have been declared or paid on Brigham's common stock to date. Brigham intends to retain all future earnings for the development of its business. In addition, the Senior Credit Facility (as defined) and the Subordinated Notes Facility (as defined) restrict Brigham's ability to pay dividends on its common stock.

On November 2, 2000, Brigham announced that it had entered into a series of financing agreements to provide funding (i) to repurchase all the debt and equity securities in Brigham held by affiliates of Enron North America at a substantial discount and (ii) to continue and expand Brigham's planned drilling program into 2001. These transactions included the issuance of the securities described below. No underwriters were involved, and therefore no underwriting commissions or discounts were paid in connection with the privately placed notes, preferred stock and warrants. The sales of these securities were made in reliance upon the exemption from the registration provisions of the Securities Act of 1933, as amended, provided by Section 4(2) thereof for transactions not involving a public offering.

Subordinated Notes Facility and Warrants. On October 31, 2000, Brigham entered into a new subordinated notes facility with Shell Capital Inc. that provided for \$20 million in borrowings. In connection with this new credit facility, Brigham issued to Shell Capital warrants to purchase an aggregate of 1,250,000 shares of Brigham common stock at an exercise price of \$3.00 per share. Terms of the warrants are described below under "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations -- Liquidity and Capital Resources -- Refinancing Transactions."

Series A Preferred Stock and Warrants. On November 1, 2000, Brigham issued to affiliates of Credit Suisse First Boston (USA), Inc. an aggregate of 1,000,000 shares of its Series A Preferred Stock and warrants to purchase an aggregate of 6,666,667 shares of Brigham common stock at an exercise price of \$3.00 per share, for a cash purchase price of \$20 million. Terms of the warrants are described below under "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations -- Liquidity and Capital Resources -- Refinancing Transactions."

ITEM 6. SELECTED FINANCIAL DATA

The following selected consolidated financial data should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and Brigham's consolidated financial statements and related notes included in "Item 8. Financial Statements and Supplementary Data."

(in thousands, except per share data)

	Year Ended December 31,				
	1996	1997	1998	1999	2000
Statement of Operations Data:					
Revenues:					
Oil and natural gas sales	\$ 6,141	\$ 9,184	\$ 13,799	\$ 14,992	\$ 19,143
Workstation revenue	627	637	390	285	53
Total revenues	6,768	9,821	14,189	15,277	19,196
Costs and expenses:					
Lease operating	726	1,151	2,172	2,259	2,139
Production taxes	362	549	850	968	1,786
General and administrative	2,199	3,570	4,672	3,481	3,100
Depletion of oil and natural gas properties	2,323	2,743	8,483	7,792	7,920
Depreciation and amortization	487	306	413	525	507
Capitalized ceiling impairment	-	-	25,926	-	-
Amortization of stock compensation	-	388	372	1	113
Total costs and expenses	6,097	8,707	42,888	15,026	15,565
Operating income (loss)	671	1,114	(28,699)	251	3,631
Other income (expense):					
Interest expense, net	(1,173)	(1,190)	(5,968)	(9,697)	(9,906)
Interest income	52	145	136	176	108
Other expense	-	-	-	(163)	(9,488)
Loss on sale of oil and natural gas properties	-	-	-	(12,195)	-
Total other income (expense)	(1,121)	(1,045)	(5,832)	(21,879)	(19,286)
Income (loss) before income taxes and extraordinary item	(450)	69	(34,531)	(21,628)	(15,655)
Income tax benefit (expense)	-	(1,186)	1,186	-	-
Loss before extraordinary item	(450)	(1,117)	(33,345)	(21,628)	(15,655)
Extraordinary item - gain on refinancing of debt, net of tax	-	-	-	-	32,267
Net income (loss)	(450)	(1,117)	(33,345)	(21,628)	16,612
Preferred dividend and accretion	-	-	-	-	275
Net income (loss) attributable to common stockholders	\$ (450)	\$ (1,117)	\$ (33,345)	\$ (21,628)	\$ 16,337
Net income (loss) per share - basic and diluted	\$ (0.05)	\$ (0.10)	\$ (2.64)	\$ (1.53)	\$ 1.01
Weighted average shares outstanding - basic and diluted	8,929	11,081	12,626	14,152	16,241
Statement of Cash Flows Data:					
Net cash provided (used) by operating activities	\$ 3,710	\$ 9,806	\$ 14,774	\$ 2,578	\$ (4,635)
Net cash provided (used) by investing activities	(11,796)	(57,300)	(86,227)	1,644	(26,071)
Net cash provided (used) by financing activities	7,731	47,748	72,321	(4,049)	28,801
Other Financial Data:					
Oil and natural gas capital expenditures	\$ 13,612	\$ 57,170	\$ 85,207	\$ 25,560	\$ 28,910
As of December 31,					
	1996	1997	1998	1999	2000
Balance Sheet Data:					
Cash and cash equivalents	\$ 1,447	\$ 1,701	\$ 2,569	\$ 2,742	\$ 837
Oil and natural gas properties, net	28,005	84,294	134,317	112,066	129,490
Total assets	33,614	92,519	150,516	125,683	146,911
Long-term debt, net	24,000	32,000	94,786	97,341	82,000
Total stockholders' equity	3,244	43,313	24,681	8,998	34,757

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Overview

Brigham is an independent exploration and production company that applies 3-D seismic imaging and other advanced technologies to systematically explore and develop onshore oil and natural gas provinces in the United States. From inception in 1990 through December 31, 2000, Brigham acquired 5,122 square miles of 3-D seismic data and drilled 498 wells delineated by 3-D seismic analysis. Through its 3-D seismic-based drilling efforts, Brigham has discovered an aggregate of 139 Bcfe of net proved reserves as of December 31, 2000, at an average net drilling cost of \$0.75 per Mcfe.

Combining its geologic and geophysical expertise with a sophisticated land effort, Brigham manages the majority of its projects from conception through 3-D acquisition, processing and interpretation and leasing. In addition, Brigham manages the negotiation and drafting of most of its geophysical exploration agreements, resulting in reduced contract risk and more consistent deal terms. Because it generates most of its projects, Brigham can often control the size of the working interest that it retains as well as the selection of the operator and the non-operating participants. Consistent with its business strategy, Brigham has increased the working interest it retained in its projects, based on capital availability and perceived risk. Brigham's average working interest in its 3-D seismic projects acquired during 1996, 1997 and 1998 was 37%, 66% and 81%, respectively, while its average working interest in its wells drilled during this period was 24%, 39% and 52%, respectively. Brigham did not acquire any new 3-D seismic in 1999 and 2000, and its average working interest in its wells drilled during these periods was 34% and 42%, respectively. Beginning in 1995, Brigham has managed operations through the drilling and production phases on an increasing portion of its 3-D seismic projects. Brigham operated 55% of its gross wells and 82% of its net wells drilled in 2000 as compared with 10% of its gross wells and 17% of its net wells drilled in 1996.

Expenditures made in oil and natural gas exploration vary from project to project depending primarily on the costs related to seismic acquisition, land and drilling, and the working interest retained by Brigham. Prior to 1997, Brigham's participants typically bore a disproportionate share of the costs of optioning available acreage and acquiring, processing and interpreting the 3-D seismic data, and Brigham and its participants each typically incurred leasing, drilling and completion costs in proportion to their ownership interests. In 1997 and 1998, Brigham retained majority working interests in its new 3-D seismic projects, and thereby reduced the financial leverage it historically received on the costs of optioning available acreage and acquiring, processing and interpreting the 3-D seismic data on its projects.

From inception through 1996, Brigham acquired 2,762 gross (781 net) square miles of 3-D seismic data. Initially, Brigham focused its exploration efforts in West Texas. Since 1996, Brigham has devoted the majority of its resources to the Anadarko Basin and Gulf Coast. With this shift in regional focus, the majority of Brigham's production volumes have shifted from oil to natural gas. To finance these project generation and drilling activities, Brigham supplemented cash flow from operations with private placements of debt and equity, commercial bank credit facilities and placements of working interests in projects with industry participants. As Brigham's cash flows from operations and other sources of capital have increased during this period, it retained larger average working interests in its projects.

In 1997 and 1998, Brigham acquired 2,360 gross (1,727 net) square miles of 3-D seismic and continued to focus the majority of its 3-D exploration efforts in the Anadarko Basin and the Gulf Coast. During these two years, Brigham acquired 1,196 square miles (51%) of 3-D seismic in the Anadarko Basin, making this basin its most active 3-D seismic acquisition province. Brigham also significantly increased its Gulf Coast activity, acquiring 942 square miles (40%) of 3-D seismic during this period. During 1997 and 1998, Brigham drilled 145 gross (65.9 net) wells based on its 3-D seismic data analysis. In addition to its drilling activities, Brigham acquired 21.3 net Bcfe of proved reserves and an interest in undeveloped acreage (the "Chitwood Acquisition") at the northern end of the Carter-Knox anticline in Grady County, Oklahoma for \$13.4 million in November 1997. As a result of these activities, Brigham's net oil and natural gas production increased from 2.1 Bcfe in 1996 to 6.6 Bcfe in 1998. Brigham's net production volumes consisted of 79% natural gas on an equivalent basis during the fourth quarter 1998 as compared with 36% during the fourth quarter 1996. Brigham supplemented cash flow from operations in 1997 and 1998 with borrowings under commercial bank credit

facilities, \$24 million raised in its initial public offering of common stock in May 1997, \$47.5 million raised through the placement of debt and equity securities in August 1998 and the placement of working interests in projects to industry participants to finance its project generation, property acquisition and drilling activities.

Brigham implemented a number of strategic initiatives during 1999 and 2000 to generate capital resources to fund its continuing exploration program while reducing its level of indebtedness. These objectives and results accomplished for each include:

- *Focusing All Planned Exploration Efforts to the Drilling of Highest-Grade 3-D Prospects in its Anadarko Basin and Gulf Coast Projects.* During 1999 and 2000, Brigham directed the vast majority of its resources to the drilling of identified prospects within natural gas trends where it had achieved historical drilling success. In addition, Brigham's drilling program during this time period consisted of a more balanced mix of exploration and development drilling projects as compared with prior drilling activity that was predominately exploratory in nature. This focused drilling emphasis contributed to substantially improved returns on Brigham's drilling investments during 1999 and 2000, with average drilling costs of \$0.62 per Mcfe and average all-in finding costs of \$0.85 per Mcfe in this two-year period.
- *Eliminating Substantially All Seismic and Land Expenditures for New Projects.* In an effort to devote the majority of its capital resources to the drilling of its identified prospect locations, Brigham did not acquire any new 3-D seismic data in 1999 and 2000. In addition to executing a high-graded drilling program, Brigham's staff of explorationists continued to interpret previously acquired 3-D seismic data within existing projects to further delineate and refine pre-drill analysis of potential drilling locations in its focus project areas.
- *Divesting Certain Producing Oil and Natural Gas Properties.* In June 1999, Brigham sold interests in certain non-operated properties in two project areas (the Chitwood Field and the Red Deer Creek Field) in its Anadarko Basin province for a total of \$17.1 million. These properties had estimated net proved reserves of 36 Bcfe as of June 1, 1999, of which approximately 67% were non-producing, and were producing an estimated 2.8 net MMcfe per day at the time of the sales. After application of the net proceeds received from these sales to the repayment of a portion of its outstanding borrowings under its bank credit facility, Brigham was able to increase its available borrowings under its bank credit facility by \$8 million. The increase in bank borrowing capacity resulting primarily from these property sales was utilized to fund a substantial portion of Brigham's capital expenditures during the second half of 1999.
- *Restructuring its Senior and Subordinated Debt Agreements.* Working closely with its senior and subordinated lenders in 1999 and early 2000, Brigham was able to amend its senior credit facility and the indenture for its then outstanding subordinated notes due 2003 to provide for increased borrowing availability and financial flexibility to preserve cash flow to fund its exploration activities. During 2000, Brigham completed several financing transactions, including the refinancing of its subordinated notes due 2003 at a substantial discount, that resulted in lower debt levels while providing funding for its 2000 and 2001 capital expenditure programs. See "-- Liquidity and Capital Resources."
- *Implementing an Overhead Reduction Plan.* Brigham implemented several initiatives during 1999 that were designed to reduce general and administrative expenses and thereby increase cash flow from operations. These cost reduction initiatives included a company-wide salary reduction effective in May 1999, the elimination of employee bonuses for 1999, subleasing a portion of Brigham's office space, certain personnel reductions and the elimination or reduction of various other discretionary expenses. As a result of these actions, Brigham's total general and administrative expenses (including amounts capitalized) were reduced 33% from the fourth quarter 1998 to the fourth quarter 1999, while per unit net general and administrative expenses decreased 43% from \$0.92 per Mcfe to \$0.52 per Mcfe during these same periods. Brigham continued its focus on minimizing discretionary overhead expenses during 2000. These continuing efforts resulted in a 6% reduction in total general and administrative expenses (including amounts capitalized) in 2000 as compared with 1999, while per unit net general and administrative expenses were further reduced by 16% from \$0.56 per Mcfe to \$0.47 per Mcfe during these same periods.

- *Raising Equity Capital.* During 1999 and 2000, Brigham raised in excess of \$15 million through the sale of interests in non-producing assets, primarily project and prospect equity sales to industry participants. In addition, Brigham issued \$4.2 million of common stock to Veritas DGC Land, Inc. ("Veritas") to satisfy payment obligations due to Veritas for seismic acquisition and processing services performed prior to 1999 and certain seismic processing services performed during 1999. In connection with its series of financing transactions effected in 2000 to fund its exploration and development program and to refinance its subordinated notes due 2003, Brigham raised \$24.5 million through private placements of common and preferred stock. See "-- Liquidity and Capital Resources."

Brigham uses the full cost method of accounting for oil and natural gas properties. Under this method, all acquisition, exploration and development costs, including payroll, interest, and other internal costs, 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 cost and proved reserves, in which case a gain or loss is recognized.

To the extent that the costs capitalized in the full-cost pool (net of depreciation, depletion and amortization and related deferred taxes) exceed the present value (using a 10% discount rate and based on period-end oil and natural gas prices) of estimated future net after-tax cash flows from proved oil and natural gas reserves plus the capitalized cost of unproved properties, such costs are charged to operations as a writedown of the carrying value of oil and natural gas properties, or a "capitalized ceiling impairment" charge. The risk that Brigham will be required to write down the carrying value of its oil and gas properties increases when oil and gas prices are depressed, even if such prices are temporary. In addition, capitalized ceiling impairment charges may occur if Brigham experiences poor drilling results or has substantial downward revisions in its estimated proved reserves. A capitalized ceiling impairment is a charge to earnings that does not impact cash flows, but does impact operating income and stockholders' equity. Once incurred, a capitalized ceiling impairment charge to oil and natural gas properties cannot be reversed at a later date. Primarily as a result of the significant declines in both oil and natural gas prices at December 31, 1998 and disappointing drilling results on several high working interest wells in 1998, Brigham recorded a capitalized ceiling impairment charge at December 31, 1998 of \$25.9 million. No assurance can be given that Brigham will not experience a capitalized ceiling impairment charge in future periods. See "-- Risk Factors -- Exploratory Drilling Is A Speculative Activity Involving Numerous Risks And Uncertain Costs; We Are Dependent On Exploratory Drilling Activities"; "-- Risk Factors -- Volatility Of Oil And Gas Markets Affects Us; Oil And Natural Gas Prices Are Volatile"; and "-- Risk Factors -- We Are Subject To Uncertainties In Reserve Estimates And Future Net Cash Flows."

Results of Operations

The following table sets forth certain operating data for the periods presented.

	Year Ended December 31,		
	1998	1999	2000
Production:			
Natural gas (MMcf).....	4,269	4,197	4,431
Oil (MBbls).....	396	346	362
Natural gas equivalent (MMcfe)	6,644	6,270	6,600
% Natural gas	64%	67%	67%
Average sales prices per unit ⁽¹⁾ :			
Natural gas (per Mcf)	\$ 2.04	\$ 2.11	\$ 1.94
Oil (per Bbl)	12.85	17.79	29.17
Natural gas equivalent (per Mcfe)	2.08	2.39	2.90
Costs and expenses per Mcfe:			
Lease operating	\$ 0.33	\$ 0.36	\$ 0.32
Production taxes.....	0.13	0.15	0.27
General and administrative.....	0.70	0.56	0.47
Depletion of oil and natural gas properties.....	1.28	1.24	1.20

(1) Reflects the effects of Brigham's hedging activities. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations -- Other Matters -- Derivative Instruments."

Year Ended December 31, 2000 Compared to Year Ended December 31, 1999

Oil and natural gas sales. Oil and natural gas sales increased 28% from \$15.0 million in 1999 to \$19.1 million in 2000. An increase in the average equivalent sales price received for oil and natural gas sales accounted for \$3.4 million of this increase and the remaining \$780,000 of this increase was the result of higher net equivalent production volumes.

Natural gas production volumes increased 6% from 4,197 MMcf in 1999 to 4,431 MMcf in 2000, while the average price received for natural gas decreased 8% from \$2.11 per Mcf in 1999 to \$1.94 per Mcf in 2000. Natural gas production volumes during 1999 included 442 MMcf attributable to properties sold by Brigham in June 1999. Excluding production attributable to these divested properties, natural gas production volumes increased 18% in 2000 as compared with adjusted production volumes in 1999.

Oil production volumes increased 5% from 346 MBbls in 1999 to 362 MBbls in 2000, while the average price received for oil increased 64% from \$17.79 per Bbl in 1999 to \$29.17 per Bbl in 2000. Oil production volumes during 1999 included 22 MBbls attributable to properties sold by Brigham in June 1999. Excluding production attributable to these divested properties, oil production volumes increased 12% in 2000 as compared with adjusted production volumes in 1999.

Oil and natural gas sales in 2000 were increased by higher realized equivalent oil and natural gas prices and production from wells completed during 2000, offset partially by the natural decline of existing production and losses from oil and natural gas hedges. See "-- Overview." As a result of hedging activities, natural gas revenues were reduced by \$9.4 million (\$2.12 per Mcf) in 2000, compared to a decrease in natural gas revenues of \$486,000 (\$0.12 per Mcf) in 1999. Oil revenues were reduced by \$107,000 (\$0.30 per Bbl) due to hedging losses in 2000. There were no gains or losses on crude oil hedges during 1999. See "-- Other Matters -- Derivative Instruments."

Workstation revenue. Workstation revenue decreased 81% from \$285,000 in 1999 to \$53,000 in 2000. Brigham recognizes workstation revenue as industry participants in its seismic programs are charged an hourly rate for the work Brigham performs on its 3-D seismic interpretation workstations. This decrease in 2000 is primarily attributable a reduction in the volume of 3-D seismic interpretation activity billable to industry participants as compared with 1999.

Lease operating expenses. Lease operating expenses decreased 5% from \$2.3 million (\$0.36 per Mcfe) in 1999 to \$2.1 million (\$0.32 per Mcfe) in 2000. This decrease was primarily due to a decrease in the number of producing wells in 2000 as compared with 1999 that was attributable to Brigham's June 1999 property divestitures and the plugging and abandonment of certain uneconomic wells. See "-- Overview."

Production taxes. Production taxes increased 85% from \$968,000 (\$0.15 per Mcfe) in 1999 to \$1.8 million (\$0.27 per Mcfe) in 2000 primarily due to higher average oil and natural gas sales prices and revenues before the effects of hedging gains or losses. The effective average production tax rate decreased from 6.3% of pre-hedge oil and natural gas sales in 1999 to 6.2% in 2000 resulting primarily from changes in the geographic distribution of Brigham's producing wells.

General and administrative expenses. Net general and administrative expenses decreased 11% from \$3.5 million (\$0.56 per Mcfe) in 1999 to \$3.1 million (\$0.47 per Mcfe) in 2000. This decrease was primarily attributable to the reduction of various administrative costs, including lower office rent due to the subleasing of a portion of Brigham's headquarters space, reduced equipment rental and maintenance expenses, and lower employee payroll and benefits expenses. See "-- Overview."

Depletion of oil and natural gas properties. Depletion of oil and natural gas properties increased 2% from \$7.8 million (\$1.24 per Mcfe) in 1999 to \$7.9 million (\$1.20 per Mcfe) in 2000. Of this increase, \$396,000 was attributable to higher production volumes, partially offset by \$268,000 due to the reduction in the depletion rate per unit of production. The decrease in depletion rate per unit of production was primarily the result of the addition of oil and natural gas reserves at lower average capital costs due to improved average finding costs during 2000.

Interest expense. Interest expense increased from \$9.7 million in 1999 to \$9.9 million in 2000 due to higher effective interest rates that were partly offset by lower outstanding debt balances. Brigham's weighted average outstanding debt balance decreased 2% from \$99.5 million in 1999 to \$97.4 million in 2000. This reduction in debt was primarily attributable to Brigham's refinancing of its senior subordinated notes due 2003 in November 2000. The effective annual interest rate on Brigham's outstanding indebtedness increased slightly from 12.6% in 1999 to 12.7% in 2000. In addition, interest expense in 2000 included (i) \$4.6 million of interest expenses that were paid in kind through the issuance of additional debt in lieu of cash, and (ii) \$2.0 million of non-cash charges related to the amortization of deferred loan fees and the amortization of discount on senior subordinated notes. Borrowings under Brigham's senior credit facility had an effective annual interest rate of 9.68% at December 31, 2000. In November 2000, Brigham refinanced its senior subordinated notes due 2003 at a substantial discount to the principal amount then outstanding. This refinancing reduced Brigham's outstanding debt borrowings and is expected to result in lower average interest rates during 2001. See "-- Liquidity and Capital Resources -- Refinancing Transactions."

Other expense. Other expense increased from \$163,000 in 1999 to \$9.5 million in 2000. Brigham recognizes other income or expense primarily related to the changes in the fair market values and the related cash flows of certain oil and natural gas derivative contracts that do not qualify for hedge accounting treatment. Other expense in 1999 included (i) \$115,000 of non-cash expenses related to the changes in the fair market values of these derivative contracts during the period, and (ii) \$48,000 of expenses related to cash settlements incurred during the period pursuant to these derivative contracts. Other expense in 2000 included (i) \$8.9 million of non-cash expenses related to the changes in the fair market values of these derivative contracts during the period, and (ii) \$603,000 of expenses related to cash settlements incurred during the period pursuant to these derivative contracts.

Extraordinary gain on refinancing of senior subordinated notes. In November 2000, Brigham repurchased all of the debt and equity securities in Brigham held by affiliates of Enron North America (the "Enron Affiliates") at a substantial discount. With a portion of the proceeds from two new financing transactions, Brigham repurchased all of the Enron Affiliates' interests in Brigham, which included (i) \$51.2 million of senior subordinated notes due 2003 (which bore interest at annual rates of 12% to 14%) and associated accrued interest obligations, (ii) warrants to purchase an aggregate of one million shares of common stock at \$2.43 per share, and (iii) 1,052,632 shares of common stock (collectively, the "Enron Securities"), for total cash consideration of \$20 million. As a result of the repurchase of the senior subordinated

notes due 2003 at a discount to the principal amount outstanding, Brigham recorded an extraordinary gain of \$32.3 million in the fourth quarter of 2000.

Year Ended December 31, 1999 Compared to Year Ended December 31, 1998

Oil and natural gas sales. Oil and natural gas sales increased 9% from \$13.8 million in 1998 to \$15 million in 1999. An increase in the average sales price received for oil and natural gas sales accounted for \$2 million of this increase and was offset by \$797,000 from a decrease in net production volumes. Production volumes for natural gas decreased 2% from 4,269 MMcf in 1998 to 4,197 MMcf in 1999, while the average price received for natural gas increased 3% from \$2.04 per Mcf in 1998 to \$2.11 per Mcf in 1999. Production volumes for oil decreased 13% from 396 MBbls in 1998 to 346 MBbls in 1999, while the average price received for oil increased 38% from \$12.85 per Bbl in 1998 to \$17.79 per Bbl in 1999. Oil and natural gas sales in 1999 were increased by higher realized oil and natural gas prices and production from wells completed during 1999, offset partially by the natural decline of existing production and from the sale of certain producing wells in the Company's mid-1999 property divestitures. See "-- Overview." As a result of hedging activities, natural gas revenues were reduced by \$486,000 (\$0.12 per Mcf) in 1999, compared to an increase in natural gas revenues of \$555,000 (\$0.13 per Mcf) in 1998. See "-- Other Matters -- Derivative Instruments."

Workstation revenue. Workstation revenue decreased 27% from \$390,000 in 1998 to \$285,000 in 1999. This decrease is primarily attributable to Brigham's increased working interests in its 3-D seismic projects in 1997 and 1998, which reduced the amount of workstation interpretation costs billable to Brigham's project participants.

Lease operating expenses. Lease operating expenses increased 4% from \$2.2 million (\$0.33 per Mcfe) in 1998 to \$2.3 million (\$0.36 per Mcfe) in 1999. This increase was primarily due to higher average working interests in its producing wells and increased well repair and workover activity in 1999 as compared with 1998, offset in part by the elimination of lease operating expenses related to wells sold by Brigham in its mid-1999 property divestitures. See "-- Overview."

Production taxes. Production taxes increased 14% from \$850,000 (\$0.13 per Mcfe) in 1998 to \$968,000 (\$0.15 per Mcfe) in 1999 primarily due to higher average oil and natural gas sales prices and revenues. The effective average production tax rate increased from 6.2% of oil and natural gas sales revenues in 1998 to 6.5% in 1999 resulting from changes in the geographic distribution of Brigham's producing wells.

General and administrative expenses. Net general and administrative expenses decreased 25% from \$4.7 million (\$0.70 per Mcfe) in 1998 to \$3.5 million (\$0.56 per Mcfe) in 1999. This decrease was primarily attributable to a series of cost reduction initiatives implemented by Brigham during 1999 to reduce overhead expense levels. These initiatives included a company-wide salary reduction effective in May 1999, the elimination of employee bonuses for 1999, a sublease of a portion of Brigham's headquarters space effective in November 1999, certain personnel reductions and the elimination or reduction of various other discretionary expenses.

Depletion of oil and natural gas properties. Depletion of oil and natural gas properties decreased 8% from \$8.5 million (\$1.28 per Mcfe) in 1998 to \$7.8 million (\$1.24 per Mcfe) in 1999. Of this decrease, \$464,000 was attributable to the lower production volumes during the period and \$227,000 was due to the reduction in the depletion rate per unit of production. The decrease in depletion rate per unit of production was primarily the result of the addition of oil and natural gas reserves at lower average capital costs due to improved average finding costs during 1999, partially offset by an increase in the percentage of Brigham's total full cost pool subject to depletion attributable to an increase in the estimate of the evaluated portion of Brigham's oil and natural gas properties.

Interest expense. Interest expense increased from \$6 million in 1998 to \$9.7 million in 1999 due to higher outstanding debt balances in 1999 at higher effective interest rates. Brigham's weighted average outstanding debt balance increased 51% from \$66 million in 1998 to \$99.5 million in 1999. This increase in debt was incurred primarily to fund Brigham's increased capital expenditures and working capital needs, net of operating cash flow, during 1998 and 1999. The effective annual interest rate on Brigham's outstanding indebtedness increased from 10.6% in 1998 to 12.6% in 1999, primarily due to Brigham's issuance of \$40 million of senior subordinated notes due 2003 in August 1998, which

bore interest at an annual rate of 12% when paid in cash and 13% when paid "in kind" through the issuance of additional subordinated notes. In addition, interest expense in 1999 included (i) \$5.5 million of interest expenses related to the subordinated notes due 2003 that was paid in kind through the issuance of additional subordinated notes in lieu of cash, and (ii) \$2.3 million of non-cash charges related to the amortization of deferred loan fees and the amortization of discount on the subordinated notes. Borrowings under Brigham's senior credit facility had an effective annual interest rate of 9.5% at December 31, 1999. See "-- Liquidity and Capital Resources."

Loss on sale of oil and natural gas properties. In June 1999, Brigham sold all of its interests in certain producing and non-producing oil and natural gas properties for a total sales price of \$17.1 million. Due to the magnitude of the reserve volumes that were attributable to these properties relative to Brigham's remaining net reserve volumes, Brigham recognized a \$12.2 million non-cash loss to reflect the difference between the sales price received (after adjustment for transaction costs) and the \$28.9 million basis allocated to the divested properties in accordance with the full-cost method of accounting for oil and gas properties. No property divestitures occurred during 1998 for which recognition of gain or loss was appropriate.

Liquidity and Capital Resources

Brigham's primary sources of capital have been credit facility and other debt borrowings, public and private equity financings, the sale of interests in projects and properties and funds generated by operations. Brigham's primary capital requirements are 3-D seismic acquisition, processing and interpretation costs, land acquisition costs and drilling expenditures.

Credit Facility

In January 1998, Brigham entered into a revolving credit agreement (as amended, the "Senior Credit Facility"), which provided for an initial borrowing availability of \$75 million. The Senior Credit Facility was amended in March 1999 to reduce the borrowing availability, extend the date of borrowing base redetermination, modify certain financial covenants, include certain additional covenants that place restrictions on Brigham's ability to incur certain capital expenditures, and to increase the interest rate on outstanding borrowings.

As a result of the completion of the majority of Brigham's strategic initiatives to improve its capital resources, including its June 1999 property divestitures and the application of the net sales proceeds to reduce borrowings outstanding under the Senior Credit Facility, Brigham and its senior lenders entered into an amendment to the Senior Credit Facility in July 1999. This amendment provided Brigham with borrowing availability of \$56 million. As consideration for this amendment, in July 1999 Brigham issued to its senior lenders warrants to purchase an aggregate of 1,000,000 shares of Brigham common stock at an exercise price of \$2.25 per share. The warrants have a seven-year term from the date of issuance and are exercisable at the holders' option at any time. An estimated value of \$1.2 million was attributed to these warrants by Brigham and was recognized as additional deferred loan fees that will be amortized and included in interest expense over the remaining period to maturity of the Senior Credit Facility.

In February 2000, Brigham entered into an amended and restated Senior Credit Facility with its existing senior lenders and a new senior lender. The Senior Credit Facility was further amended in October 2000. The amended and restated Senior Credit Facility provides Brigham with \$75 million in borrowing availability for a three-year term.

As a result of the February 2000 amendments, \$30 million of the Senior Credit Facility held by one of the lenders is convertible into shares of Brigham common stock (the "Convertible Notes") in the following amounts and prices: (i) \$10 million is convertible at \$3.90 per share, (ii) \$10 million is convertible at \$6.00 per share and (iii) \$10 million is convertible at \$8.00 per share. As of December 31, 2000, Brigham had \$75 million in borrowings outstanding under the Senior Credit Facility, of which the Convertible Notes are \$30 million.

In connection with Brigham's refinancing of its subordinated notes due 2003 (see "-- Subordinated Notes" and "-- Refinancing Transactions") in October 2000, Brigham entered into an amendment to the Senior Credit Facility that, among other things, permitted the issuance of new subordinated notes and new preferred stock to provide funding for the repurchase of the subordinated notes due 2003 and equity interests in Brigham held by the Enron Affiliates. In addition, the minimum interest coverage ratio (as defined) tests of the Senior Credit Facility were amended to reflect Brigham's expected cash flow and interest expense beginning in the fourth quarter of 2000 subsequent to the Refinancing Transactions (as defined), and Brigham conditionally waived certain rights to force conversion of the portion of the borrowings under the Senior Credit Facility that are convertible at \$3.90 per share.

If the Senior Credit Facility is repaid at maturity or is prepaid prior to maturity without payment of cash premiums, the warrants to purchase Brigham common stock issued to the new participant in the Senior Credit Facility become exercisable. Further, to the extent Brigham chooses to prepay any of the Convertible Notes without the warrants becoming exercisable, and also assuming the lender chooses not to convert to equity upon notice of such prepayment, Brigham will be required to pay a premium above the face value of the Convertible Notes to the lender. Such premium amounts would range from 150% to 110%, depending upon the timing of the prepayment. Such prepayment, however, would require prior approval of the original lenders to the Senior Credit Facility. In addition, certain financial covenants of the Senior Credit Facility were amended or added in the July 1999, February 2000 and October 2000 amendments. In connection with the February 2000 amendment, Brigham reset the price of the warrants previously issued to its existing senior lenders to purchase one million shares of Brigham common stock from the then current exercise price of \$2.25 per share to \$2.02 per share.

Principal outstanding under the Senior Credit Facility is due at maturity on December 31, 2002, with interest due monthly for base rate tranches or periodically as LIBOR tranches mature. The annual interest rate for borrowings under the Senior Credit Facility is either the lender's base rate or LIBOR plus 3.00%, at Brigham's option. Obligations under the Senior Credit Facility are secured by substantially all of Brigham's oil and natural gas properties and other tangible assets. At March 20, 2001, Brigham had \$75 million in borrowings outstanding under the Senior Credit Facility, which bear interest at an annual rate of approximately 8.35%.

The Senior Credit Facility has certain financial covenants, including current and interest coverage ratios, as defined. Brigham and its senior lenders effected the amendments to the Senior Credit Facility described above in part to enable Brigham to comply with certain financial covenants of the Senior Credit Facility, including the minimum current ratio (as defined), minimum interest coverage ratio (as defined), and the limitation on capital expenditures related to seismic and land activities. Should Brigham be unable to comply with certain of the financial or other covenants, its senior lenders may be unwilling to waive compliance or amend the covenants in the future. In such instance, Brigham's liquidity may be adversely affected, which could in turn have an adverse impact on its future financial position and results of operations.

Subordinated Notes

In August 1998, Brigham issued \$50 million of debt and equity securities to affiliates of Enron Corp. The securities issued by Brigham in connection with this financing transaction included: (i) \$40 million of subordinated notes due 2003, (ii) warrants to purchase an aggregate of one million shares of Brigham common stock at a price of \$10.45 per share, and (iii) 1,052,632 shares of Brigham common stock at a price of \$9.50 per share.

As described below, Brigham repurchased the subordinated notes due 2003, together with all equity interests in Brigham held by the Enron Affiliates, for \$20 million in cash in November 2000 (see "-- Refinancing Transactions").

Refinancing Transactions

On October 31, 2000 and November 1, 2000, Brigham entered into a series of financing agreements to provide funding (i) to repurchase all the debt and equity securities in Brigham held by affiliates of Enron North America at a substantial discount, and (ii) to continue and expand Brigham's planned drilling program into 2001.

Financing and Repurchase Transactions. Brigham raised an aggregate of \$40 million in these financing transactions through the issuance of (i) \$20 million in new subordinated notes and warrants to purchase Brigham common stock to Shell Capital Inc., and (ii) \$20 million in new mandatorily redeemable preferred stock and warrants to purchase Brigham common stock to affiliates of Credit Suisse First Boston (USA), Inc. (the "CSFB Affiliates"). With a portion of the proceeds from these two financing transactions, Brigham purchased all of the Enron Affiliates' interests in Brigham, which included (i) \$51.2 million of outstanding subordinated notes due 2003 and associated accrued interest obligations, (ii) warrants to purchase one million shares of common stock at \$2.43 per share, and (iii) 1,052,632 shares of common stock (collectively, the "Enron Securities"), for total cash consideration of \$20 million. The remaining approximate \$17.5 million in net capital availability raised from these financing transactions, after the repurchase of the Enron Securities and the payment of fees and expenses, was available for Brigham to fund its planned drilling program into 2001.

Subordinated Notes Facility. The \$20 million of new subordinated notes issued to Shell Capital Inc. (the "SCI Notes") bear interest at 10.75% per annum and have no principal repayment obligations until maturity in 2005. The SCI Notes will be issued pursuant a multi-draw facility (the "Subordinated Notes Facility") at borrowing increments of at least \$1 million, and such funds cannot be redrawn once they have been repaid. At Brigham's option, up to 50% of the interest payments on the SCI Notes during the first two years can be satisfied by payment-in-kind ("PIK") through the issuance of additional SCI Notes in lieu of cash. The SCI Notes are secured obligations ranking junior to Brigham's existing \$75 million Senior Credit Facility. The SCI Notes have a five-year maturity, are redeemable at Brigham's option for face value at anytime, and have certain financial and other covenants. The warrants to purchase an aggregate of 1,250,000 shares of Brigham common stock issued to Shell Capital Inc. (the "SCI Warrants") have a term of seven years, an exercise price of \$3.00 per share and a cashless exercise feature. For financial reporting purposes, the SCI Warrants were valued using the Black-Scholes valuation model and the estimated value of \$2.9 million was recorded as deferred loan costs that will be amortized over the five year term of the SCI Notes. As of December 31, 2000 and March 20, 2001, Brigham had \$7 million and \$16 million, respectively, of borrowings outstanding under the Subordinated Notes Facility.

Series A Preferred Stock. The \$20 million of mandatorily redeemable preferred stock (the "Series A Preferred Stock") issued to the CSFB Affiliates bears dividends at a rate of 6% per annum if paid in cash and 8% per annum if paid-in-kind through the issuance of additional Series A Preferred Stock in lieu of cash. At Brigham's option, up to 100% of the dividend payments on the Series A Preferred Stock during the first five years can be satisfied through the issuance of PIK dividends. The Series A Preferred Stock has a ten-year maturity and is redeemable at Brigham's option at 100% or 101% of par value (depending upon certain conditions) at anytime prior to maturity. The warrants to purchase an aggregate of 6,666,667 shares of Brigham common stock issued to the CSFB Affiliates (the "Series A Warrants") have a term of ten years, an exercise price of \$3.00 per share and must be exercised, if Brigham so requires, in the event that Brigham common stock trades at or above \$5.00 per share for 60 consecutive trading days. The exercise price of the Series A Warrants is payable either in cash or in shares of Series A Preferred Stock, valued at liquidation value plus accrued dividends. If Brigham requires exercise of the Series A Warrants, proceeds from the exercise of the Series A Warrants will be used to fund the redemption of a similar value of then outstanding Series A Preferred Stock. For financial reporting purposes, the Series A Warrants were valued at \$11.5 million using the Black-Scholes valuation model and were recorded as additional paid-in capital in the year ended December 31, 2000. Pursuant to the terms of the securities purchase agreement related to the Series A Preferred Stock, Brigham agreed to nominate one representative of one of the CSFB Affiliates to serve as a member of Brigham's board of directors so long as the CSFB Affiliates or their affiliates own at least 10% of the Series A Preferred Stock issued in November 2000, or at least 5% of the outstanding shares of Brigham common stock. In March 2001, Brigham sold an additional \$10 million of Series A Preferred Stock to affiliates of CSFB (see "-- Equity Placements -- Private Placement of Preferred Stock"). As of December 31, 2000 and March 20, 2001, Brigham had \$20.3 million and \$30.3 million (liquidation value), respectively, of Series A Preferred Stock outstanding.

Sales of Interests in Projects and Oil and Natural Gas Properties

Duke Project Financing. In February 1999, Brigham entered into a project financing arrangement with Duke Energy Financial Services, Inc. ("Duke") to fund the continued exploration of five Anadarko Basin projects covered by approximately 200 square miles of 3-D seismic data acquired in 1998. In this transaction, Brigham conveyed 100% of its working interest (land and seismic) in these project areas to a newly formed limited liability company (the "Brigham-Duke LLC") for total consideration of \$10 million. Brigham entered into this project financing arrangement to enable it to recoup substantially all of its pre-seismic land and seismic data acquisition costs incurred in these project areas and to provide the capital to fund the drilling of the first six wells within these projects. Brigham served as the managing member of the Brigham-Duke LLC with a 1% interest, and Duke was the sole remaining member with a 99% interest. Pursuant to the terms of the Brigham-Duke LLC agreement, Brigham paid 100% of the drilling and completion costs for all wells drilled by the Brigham-Duke LLC within the designated project areas in exchange for a 70% working interest in the wells (and their allocable drilling and spacing units), with the remaining 30% working interest remaining in the Brigham-Duke LLC, subject in each instance to proportionate reduction by any ownership rights held by third parties. Upon 100% project payout, Brigham had the right to back-in for 80% of the Brigham-Duke LLC's working interest in all of the then producing wells (and their allocable drilling and spacing units) and a 94% working interest in any wells (and their allocable drilling and spacing units) drilled after payout within the designated project areas governed by the Brigham-Duke LLC agreement, thereby increasing Brigham's effective working interest in the Brigham-Duke LLC wells from 70% to 94%. In February 2001, Duke, as majority member of the Brigham-Duke LLC, elected to dissolve the Brigham-Duke LLC. As a result, any ownership of remaining undeveloped land and/or seismic data within the Brigham-Duke LLC project areas will be transferred to Duke following the dissolution of the Brigham-Duke LLC.

Mid-1999 Property Sales. In June 1999, Brigham sold certain producing and non-producing oil and natural gas properties located in its Anadarko Basin province to two separate parties for a total of \$17.1 million. The divested properties were located in two fields operated by third parties – the Chitwood Field in Grady County, Oklahoma (originally acquired by Brigham for \$13.4 million in the Chitwood Acquisition in November 1997), and the Red Deer Creek Field in Roberts County, Texas. Brigham's independent reservoir engineers estimated net proved reserve volumes attributable to the properties as of June 1, 1999 of approximately 36 Bcfe, of which 33% were classified as proved developed producing reserves and 59% were natural gas. Brigham estimated that net production volumes from the divested properties were 2.8 MMcfe per day at the time of the sales. Brigham used the proceeds from these transactions to reduce borrowings under its credit facility, which contributed to provide \$8 million in borrowing availability under Brigham's then existing credit facility that was used to fund working capital needs and capital expenditures during the second half of 1999. The effective date of each transaction was June 30, 1999.

Equity Placements

Veritas Equity Issuances. On March 30, 1999, Brigham entered into an agreement with Veritas DGC Land, Inc. to exchange 1,002,865 shares of newly issued Brigham common stock valued at \$3.50 per share for approximately \$3.5 million of payment obligations due to Veritas in 1999 for certain seismic acquisition and processing services previously performed. In addition, this agreement provided for the payment by Brigham of up to \$1 million in future seismic processing services to be performed by Veritas in newly issued shares of Brigham common stock valued at \$3.50 per share, in the event that Brigham did not elect to pay for such services in cash. The settlement of these future seismic processing services was determined on a quarterly basis through September 30, 1999. Pursuant to this agreement, Brigham issued a total of 1,211,580 shares of common stock to Veritas to satisfy \$4.2 million in aggregate payment obligations due to Veritas for seismic acquisition and processing services performed prior to 1999 and certain seismic processing services performed during 1999.

Private Placement of Common Stock. On February 22, 2000, Brigham entered into an agreement to issue 2,195,122 shares of common stock and 731,707 warrants to purchase common stock for total consideration of \$4.5 million in a private placement to a group of institutional investors led by affiliates of two members of Brigham's board of directors. The equity sale consisted of units that include one share of common stock priced at \$2.0525 per share and one-third of a warrant to purchase Brigham common stock at an exercise price of \$2.5625 per share with a three-year term. Pricing of this private equity placement was based on the average market price of Brigham common stock during a twenty trading

day period prior to issuance. Net proceeds from this equity placement were used to fund a portion of Brigham's capital expenditures and working capital obligations during 2000.

Private Placement of Preferred Stock. On March 5, 2001, Brigham sold \$10 million of additional Series A Preferred Stock and warrants (the "New CSFB Warrants") to affiliates of CSFB in a private placement transaction. The conditions to Brigham's receipt of the proceeds from this transaction were fulfilled on March 22, 2001. The New CSFB Warrants to purchase an aggregate of 2,105,263 shares of Brigham common stock have a term of ten years, an exercise price of \$4.75 per share and must be exercised, if Brigham so requires, in the event that Brigham common stock trades at an average of at least 150% of the exercise price (currently, \$7.125 per share) for 60 consecutive trading days. The exercise price of the New CSFB Warrants is payable either in cash or in shares of Series A Preferred Stock, valued at liquidation value plus accrued dividends. If Brigham requires exercise of the New CSFB Warrants, proceeds from the exercise of the New CSFB Warrants will be used to fund the redemption of a similar value of then outstanding Series A Preferred Stock. For financial reporting purposes, the New CSFB Warrants were valued at approximately \$4.5 million using the Black-Scholes valuation model and were recorded as additional paid-in capital in March 2001.

Cash Flow Analysis

Cash Flows from Operating Activities. Cash flows provided (used) by operating activities were (\$4.6) million in 2000, \$2.6 million in 1999, and \$14.8 million in 1998. The decrease in cash flows for 2000 as compared to 1999 was primarily attributable to changes in working capital (a \$13.2 million reduction in cash flow from working capital items in 2000 compared to a \$5 million reduction in cash flow from working capital items in 1999), offset in part by a \$1.1 million increase in cash flow from operations before working capital. Cash flow from operations before working capital changes were \$8.6 million in 2000 as compared to \$7.5 million in 1999. The decrease in cash flows for 1999 compared to 1998 was primarily attributable to changes in working capital (a \$5 million reduction in cash flow from working capital items in 1999 compared to an \$11.9 million increase in cash flow from working capital items in 1998).

Cash Flows from Investing Activities. Cash flows provided (used) by investing activities were (\$26.1) million in 2000, \$1.6 million in 1999 and (\$86.2) million in 1998. The decrease in cash flow from investing activities in 2000 were primarily attributable to (i) an increase in Brigham's capital expenditures related to exploration and development activities, and (ii) a reduction in proceeds received from the sale of oil and natural gas properties, as compared with those in 1999. The increase in net cash flow from investing activities in 1999 was due to the combined effects of significantly reduced net capital expenditures and a total of \$27.1 million of proceeds received from the sales of oil and natural gas properties, which consisted principally of Brigham's mid-1999 producing property divestitures and its sales of promoted interests in certain 3-D seismic projects and drilling prospects in its Anadarko Basin and Texas Gulf Coast regions. Capital expenditures (before the application of net proceeds received from the sales of interests in projects) were \$28.9 million in 2000, \$25.6 million in 1999 and \$85.2 million in 1998.

After acquiring 2,361 gross (1,727 net) square miles of 3-D seismic data in 1997 and 1998, Brigham did not acquire any new 3-D seismic data during 1999 and 2000. Brigham's drilling efforts during the past three years resulted in the completion of 24 (9.2 net) wells in 2000, 19 (6.3 net) wells in 1999, and 50 (26.3 net) wells in 1998, which contributed to aggregate net increases in proved reserve volumes (net of revisions to previous estimates) of 18.4 Bcfe in 2000, 28.7 Bcfe in 1999 and 31.2 Bcfe in 1998. In addition, Brigham sold interests in certain 3-D seismic data for \$3.9 million in 2000, sold interests in certain producing and non-producing properties in 1999 for a total of \$27.1 million, and acquired certain producing properties and related interests for \$1 million in 1998.

Cash Flows from Financing Activities. Cash flows provided by financing activities in 2000 were \$28.8 million, principally due to the combined effects of increased borrowings under its Senior Credit Facility and Subordinated Notes Facility, the repurchase of its senior subordinated notes due 2003, the issuance of \$20 million of mandatorily redeemable preferred stock and warrants, and the placement of common stock that provided \$4.2 million. Cash flows used by financing activities in 1999 were \$4.1 million, principally due to the net repayment of borrowings outstanding under Brigham's Senior Credit Facility and the payment of deferred loan fees. Cash flows provided by financing activities in 1998 were \$72.3 million, primarily as a result of borrowings under the Brigham's Senior Credit Facility, the issuance of the senior subordinated notes due 2003 and the sale of \$10 million of common stock.

Capital Expenditures

Continuing its strategy initiated in 1999 to harvest its prior 3-D seismic project investments, Brigham intends to focus substantially all of its efforts and available capital resources in 2001 to the drilling and monetization of its highest grade prospects within its over 5,000 square mile inventory of 3-D seismic data. Brigham's planned 2001 capital expenditure budget is estimated to be \$32 million, which includes approximately \$22 million for drilling projects, \$4 million for acreage leasing and G&G activities, and \$6 million for capitalized overhead and interest costs. Brigham's planned 2001 drilling program consists of a balanced blend of higher potential exploration tests and lower risk development drilling projects, driven to a large extent by the development of several significant exploratory discoveries completed during 2000. Approximately 34% of budgeted 2001 drilling expenditures are targeted for exploratory prospects, 52% for development locations and the remaining 14% for development locations that are contingent upon drilling success during the year. In addition, over 80% of Brigham's budgeted drilling expenditures are focused in five project areas in the Springer and Hunton trends of the Anadarko Basin and the Vicksburg and Frio trends of the Texas Gulf Coast. Brigham intends to fund its budgeted capital expenditures through a combination of cash flow from operations, available borrowings under its Subordinated Notes Facility and the net proceeds from its private placements of Series A Preferred Stock in November 2000 and March 2001. Additionally, Brigham will continue to seek opportunities to supplement its available capital resources through selective sales of interests in non-producing assets, including interests in its 3-D seismic projects and promoted interests in future drilling prospects or locations. See "Item 2. Properties -- Primary Exploration Provinces."

Due to its active exploration and development activities, Brigham has experienced and expects to continue to experience substantial working capital requirements. While Brigham believes that cash flow from operations and borrowings under its Subordinated Notes Facility should allow it to finance its planned operations through 2001 based on current conditions and expectations, additional financing will be required in the future to fund Brigham's exploration and development activities. In the event additional financing is not available, Brigham may be required to curtail or delay its planned activities.

Other Matters

Derivative Instruments

Brigham believes that hedging, although not free of risk, allows it to reduce its exposure to oil and natural gas sales price fluctuations and thereby to achieve more predictable cash flows. However, hedging arrangements, when utilized, may limit the benefit to Brigham of increases in the prices of the hedged commodity. Moreover, Brigham's hedging arrangements generally do not apply to all of its production and thus provide only partial price protection against declines in commodity prices. Brigham expects that the amount of its hedges will vary from time to time. See "-- Risk Factors -- Our Hedging Transactions May Not Prevent Losses" and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

In 1998, Brigham began using natural gas swap arrangements in an attempt to reduce its sensitivity to volatile commodity prices as its production base became increasingly weighted toward natural gas. Pursuant to these arrangements, Brigham exchanges a floating market price for a fixed contract price. Brigham makes payments when the floating price exceeds the fixed price for a contract month, and Brigham receives payments when the fixed price exceeds the floating price. Settlements of these swaps are based on the difference between regional market index prices for a contract month and the fixed contract price for the same month.

Total natural gas purchased and sold subject to swap arrangements entered into by Brigham was 2,750,000 MMBtu in 1998, 5,025,000 MMBtu in 1999, and 5,490,000 MMBtu in 2000. Brigham accounted for these transactions as hedging activities and, accordingly, adjusted the price received for oil and natural gas production during the period the hedged transactions occurred. Adjustments to the price received for natural gas under these swap arrangements resulted in an increase in natural gas revenues of \$555,000 in 1998 and decreases in natural gas revenues of \$486,000 in 1999 and \$9.4 million in 2000. In addition, Brigham's oil revenues were reduced by \$107,000 in 2000 as a result of its crude oil collar hedging arrangements outstanding during the year. Brigham did not have any outstanding crude oil hedging

contracts during 1998 and 1999.

In September 1999, Brigham sold call options on a portion of its future oil and natural gas production. Brigham applied the proceeds from the sale of these call options to increase the effective fixed swap price on its then existing natural gas hedging contracts during the months of October 1999 through January 2000 by an average of \$0.57 per MMBtu. For accounting purposes, the improvement in Brigham's fixed natural gas swap price attributable to these transactions was not reflected in reported revenues. Rather, it was reflected in (i) other income (expense) on the income statement, and (ii) amortization of deferred loss on derivatives instruments and market value adjustment for derivatives instruments on the cash flow statement.

The following tables summarize Brigham's outstanding oil and natural gas derivative contracts as of December 31, 2000:

Natural Gas Derivative Contracts

	<u>Pricing Basis</u>	<u>Monthly Contract Term</u>	<u>2001</u>		<u>2002</u>	
			<u>Volumes Hedged (MMBtu)</u>	<u>Average Contract Price (\$/MMBtu)</u>	<u>Volumes Hedged (MMBtu)</u>	<u>Average Contract Price (\$/MMBtu)</u>
Fixed Price Swaps:						
Contract #1	ANR Oklahoma	January 2001 - April 2001	600,000	\$2.0650	--	--
Contract #2	Houston Ship Channel	January 2001 - April 2001	600,000	\$2.1500	--	--
Contract #3	TETCO South Texas	January 2001 - April 2001	600,000	\$2.0575	--	--
Fixed Price Cap	ANR Oklahoma	May 2001 - June 2002	2,450,000	\$2.5498	1,810,000	\$2.6326
Fixed Price Floor	ANR Oklahoma	May 2001 - December 2001	765,000	\$1.8000	--	--

Crude Oil Derivative Contracts

	<u>Pricing Basis</u>	<u>Monthly Contract Term</u>	<u>2001</u>		<u>2002</u>	
			<u>Volumes Hedged (Bbls)</u>	<u>Average Contract Price (\$/Bbl)</u>	<u>Volumes Hedged (Bbls)</u>	<u>Average Contract Price (\$/Bbl)</u>
Fixed Price Cap	NYMEX	January 2001 - December 2001	109,200	\$26.15	--	--
Fixed Price Floor	NYMEX	January 2001 - December 2001	109,200	\$17.36	--	--

Effects of Inflation and Changes in Prices

Brigham's 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 Brigham is required to bear for operations. Inflation has had a minimal effect on Brigham.

Environmental and Other Regulatory Matters

Brigham's 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 Brigham believes it is in substantial compliance with all applicable laws and regulations, the requirements imposed by laws and regulations are frequently changed and subject to interpretation, and Brigham is unable to predict the ultimate cost of compliance with these requirements or their effect on its operations. Any suspensions, terminations or inability to meet applicable bonding requirements could materially adversely affect Brigham's financial condition and operations. Although significant expenditures may be required to comply with governmental laws and regulations applicable to Brigham, compliance has not had a material adverse effect on the earnings or competitive position of Brigham. Future regulations may add to the cost of, or significantly limit, drilling activity. See "-- Risk Factors -- We Are Subject To Various Governmental Regulations And Environmental Risks," "Item 1. Business -- Governmental Regulation" and "Item 1. Business -- Environmental Matters."

Recent Accounting Pronouncements

In June 1998, the Financial Accounting Standards Board (the "FASB") issued Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("FAS 133"). The FASB has subsequently issued Statements of Financial Accounting Standards No. 137 and 138, which are amendments to FAS 133. FAS 133, as amended, is effective for fiscal years beginning after June 15, 2000. Brigham adopted FAS 133 on January 1, 2001.

FAS 133, as amended, establishes accounting and reporting standards for derivative instruments and for hedging activities. All derivative instruments will be 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 derivative contracts consist primarily of cash flow hedge transactions in which Brigham is hedging the variability of cash flows related to a forecasted transaction. Changes in the fair value of these derivative instruments will be reported in other comprehensive income and will be reclassified as earnings in the periods in which earnings are impacted by the variability of the cash flows of the hedged item. The ineffective portion of all hedges will be recognized in current period earnings.

In January 2001, Brigham recorded a net of tax cumulative effect adjustment of \$11.8 million to other comprehensive income to recognize the fair value (liability) of all derivative instruments which qualify for hedge accounting treatment in accordance with FAS 133.

Forward Looking Information

Brigham or its representatives may make forward looking statements, oral or written, including statements in this report, press releases and filings with the SEC, regarding estimated future net revenues from oil and natural gas reserves and the present value thereof, planned capital expenditures (including the amount and nature thereof), increases in oil and gas production, the number of wells it anticipates drilling during 2001 and Brigham's financial position, business strategy and other plans and objectives for future operations. Although Brigham believes that the expectations reflected in these forward looking statements are reasonable, there can be no assurance that the actual results or developments anticipated by Brigham will be realized or, even if substantially realized, that they will have the expected effects on its business or operations. Among the factors that could cause actual results to differ materially from Brigham's expectations are general

economic conditions, inherent uncertainties in interpreting engineering data, operating hazards, delays or cancellations of drilling operations for a variety of reasons, competition, fluctuations in oil and gas prices, availability of sufficient capital resources to Brigham and its project participants, government regulations and other factors set forth among the risk factors noted below or in the description of Brigham's business in Item 1 of this report. All subsequent oral and written forward looking statements attributable to Brigham or persons acting on its behalf are expressly qualified in their entirety by these factors. Brigham assumes no obligation to update any of these statements.

Risk Factors

We Are Substantially Leveraged

Our outstanding long-term debt was \$82 million as of December 31, 2000, and \$91 million as of March 20, 2001. The credit agreements related to our Senior Credit Facility and Subordinated Notes Facility limit the amount of additional debt borrowings, including borrowings under these facilities or other senior or subordinated indebtedness. As of March 20, 2001, we had no additional borrowing availability under our Senior Credit Facility and \$4 million in additional permitted borrowing availability under our Subordinated Notes Facility. In addition, Brigham held as cash \$9.9 million in net proceeds from the March 2001 private placement of Series A Preferred Stock.

Our level of indebtedness will have several important effects on our operations, including those listed below.

- We will dedicate a substantial 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 in our credit facilities 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 also be required to alter our capitalization significantly to accommodate future exploration, development or acquisition activities. These changes in capitalization may significantly alter our leverage and dilute the equity interests of existing stockholders. Our ability to meet our debt service obligations and to reduce our total indebtedness will be dependent upon our future performance, which will be subject to general economic conditions and to financial, business and other factors affecting our operations, many of which are beyond our control. We cannot assure you that our future performance will not be harmed by such economic conditions and financial, business and other factors. See "-- Liquidity and Capital Resources."

We Have Substantial Capital Requirements

We make and will continue to make substantial capital expenditures in our exploration and development projects. While we believe that our cash flow from operations and borrowings under our Subordinated Notes Facility should allow us to finance our planned operations through 2001 based on current conditions and expectations, additional financing will be required in the future to fund our exploration and development activities. We cannot assure you that we will be able to secure additional financing on reasonable terms or at all, or that financing will continue to be available to us under our existing or new financing arrangements. Without additional capital resources, our drilling and other activities may be limited and our business, financial condition and results of operations may suffer. See "-- Liquidity and Capital Resources."

Volatility Of Oil And Gas Markets Affects Us; Oil And Natural Gas Prices Are Volatile

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. Market prices of oil and natural gas depend on many factors beyond our control, including:

- worldwide and domestic supplies of oil and natural gas;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- political instability or armed conflict in oil-producing regions;
- 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.

We cannot predict future oil and natural gas price movements with certainty. During 2000, the high and low settlement prices for oil on the NYMEX were \$37.20 per Bbl and \$23.85 per Bbl, and the high and low settlement prices for natural gas on the NYMEX were \$9.98 per MMBtu and \$2.17 per MMBtu. Significant declines in oil and natural gas prices for an extended period may have the following effects on our business:

- limit our financial condition, liquidity, ability to finance planned capital expenditures and results of operations;
- reduce the amount of oil and natural gas that we can produce economically;
- cause us to delay or postpone some of our capital projects;
- reduce our revenues, operating income and cash flow; and
- reduce the carrying value of our oil and natural gas properties.

Our Hedging Transactions May Not Prevent Losses

In an attempt to reduce our sensitivity to energy price volatility, we use swap and collar hedging arrangements that generally result in a fixed price or a range of minimum and maximum price limits over a specified monthly time period. If we do not produce our oil and natural gas reserves at rates equivalent to our hedged position, we would be required to satisfy our obligations under hedging contracts on potentially unfavorable terms without the ability to hedge that risk through sales of comparable quantities of our own production. This situation occurred during a portion of 1999 and again during portions of 2000, due in part to our sale of certain producing reserves in mid-1999. As a result, our cash flow was significantly reduced, particularly during 2000. Because the terms of our hedging 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 hedged prices and actual results could harm our anticipated profit

margins and our ability to manage the risk associated with fluctuations in oil and natural gas prices. Hedging contracts limit the benefits we will realize if actual prices rise above the contract prices. We could be financially harmed if the other party to the hedging contracts proves unable or unwilling to perform its obligations under such contracts. See "-- Other Matters -- Derivative Instruments" and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

Exploratory Drilling Is A Speculative Activity Involving Numerous Risks And Uncertain Costs; We Are Dependent On Exploratory Drilling Activities

Our revenues, operating results and future rate of growth depend highly upon the success of our exploratory drilling program. Exploratory drilling involves numerous risks, including the risk that we will not encounter commercially productive natural gas or oil reservoirs. We cannot always 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.

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. We could incur losses because our use of 3-D seismic data and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies. Even when fully utilized and properly interpreted, our 3-D seismic data and other advanced technologies only assist us in identifying subsurface structures and do not indicate whether hydrocarbons are in fact present in those structures. Because we interpret the areas desirable for drilling from 3-D seismic data gathered over large areas, we may not acquire option and lease rights until after the seismic data is available and, in some cases, until the drilling locations are also identified. Although we have identified numerous potential drilling locations, we cannot assure you that we will ever lease, drill or produce oil or natural gas oil from these or any other potential drilling locations. We cannot assure you that we will be successful in our drilling activities, that our overall drilling success rate for activity within a particular province will not decline, or that our completed wells will ultimately produce our estimated economically recoverable reserves. Unsuccessful drilling activities could materially harm our operations and financial condition.

We Are Subject To Various Casualty Risks

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. See "Item 1. Business -- Operating Hazards and Uninsured Risks."

We May Not Have Enough Insurance To Cover Some Operating Risks

We maintain insurance coverage against some, but not all, potential losses in order to protect against operating hazards. We may elect to self-insure if our management believes that the cost of insurance, although available, is excessive relative to the risks presented. We generally maintain insurance for the hazards and risks inherent in drilling for and producing and transporting oil and natural gas and believe this insurance is adequate. If an event occurs that is not covered, or not fully covered, by insurance, it could harm our financial condition and results of operations. In addition, we cannot fully insure against pollution and environmental risks.

The Marketability Of Our Production Is Dependent On Facilities That We Typically Do Not Own Or Control

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. Our ability to produce and market oil and natural gas could be harmed by any dramatic change in market factors or by:

- federal and state regulation of oil and natural gas production and transportation;
- tax and energy policies;
- changes in supply and demand; and
- general economic conditions.

We Have Historical Operating Losses And Our Future Results May Vary; We Have Incurred Net Losses In Each Year Of Operation

We cannot assure you that we will be profitable in the future. At December 31, 2000, we had an accumulated deficit of \$38.4 million and total stockholders' equity of \$34.8 million. We have recognized the following annual net losses before extraordinary items since 1995: \$1.6 million in 1995, \$450,000 in 1996, \$1.1 million (including a net \$1.2 million non-cash deferred income tax charge incurred in connection with our conversion from a partnership to a corporation) in 1997, \$33.3 million (including a \$25.9 million non-cash writedown in the carrying value of our oil and natural gas properties) in 1998, \$21.6 million (including a \$12.2 million non-cash loss on the sale of oil and natural gas properties) in 1999, and \$15.7 million in 2000. See "Item 6. Selected Financial Data."

Our Future Operating Results May Fluctuate

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.

Maintaining Reserves And Revenues In The Future Depends On Successful Exploration And Development

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 will decline as reserves are produced. Our future oil and natural gas production depends highly upon our ability to economically find, develop or acquire reserves in commercial quantities.

The business of exploring for or developing reserves is capital intensive. Reductions in our cash flow from operations and limitations on or unavailability of external sources of capital may impair our ability to make the necessary capital investment to maintain or expand our asset base of oil and natural gas reserves. In addition, we cannot be certain that our future exploration and development activities will result in additional proved reserves or that we will be able to drill productive wells at acceptable costs. Furthermore, although significant increases in prevailing prices for oil and natural gas could cause increases in our revenues, our finding and development costs could also increase. Finally, we participate in a percentage of our wells as a non-operator. The failure of an operator of our wells to adequately perform operations, or an operator's breach of the applicable agreements, could harm us.

We Are Subject To Uncertainties In Reserve Estimates And Future Net Cash Flows

There is substantial uncertainty in estimating quantities of proved reserves and projecting future production rates and the timing of development expenditures. No one can measure underground accumulations of oil and natural gas in an exact way. Accordingly, oil and natural gas reserve engineering requires subjective estimations of those accumulations. Estimates of other engineers might differ widely from those of our independent petroleum engineers. Accuracy of reserve estimates depends on the quality of available data and on engineering and geological interpretation and judgment. Our independent petroleum engineers may make material changes to reserve estimates based on the results of actual drilling, testing, and production. As a result, our reserve estimates often differ from the quantities of oil and natural gas we ultimately recover. Also, we make certain assumptions regarding future oil and natural gas prices, production levels, and operating and development costs that may prove incorrect. Any significant variance from these assumptions could greatly affect our estimates of reserves, the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery and estimates of the future net cash flows. See "Item 2. Properties -- Oil and Natural Gas Reserves."

Actual future net cash flows from our oil and natural gas properties also will be affected by factors such as:

- the amount and timing of actual production;
- supply and demand for oil and natural gas;
- limits or increases in consumption by gas purchasers; and
- changes in governmental regulations or taxation.

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

We Face Significant Competition

We operate in the highly competitive areas of oil and natural gas exploration, exploitation, acquisition and production with other companies. 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. See "Item 1. Business -- Competition."

We Are Subject To Various Governmental Regulations And Environmental Risks

Our business is subject to 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 safety matters. Although we believe we are in substantial compliance with all applicable laws and regulations, 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 environmental laws and regulations adopted by federal, state and local governmental authorities. 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 natural gas, oil, 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 cannot be certain that existing environmental laws or regulations, as currently interpreted or reinterpreted in the future, or future laws or regulations will not harm our results of operations and financial condition. See "Item 1. Business -- Governmental Regulation; and -- Environmental Matters."

Our Business May Suffer If We Lose Key Personnel

We have assembled a team of geologists, geophysicists and engineers who have considerable experience in applying 3-D imaging technology to explore for and to develop oil and natural gas. We depend upon the knowledge, skills and experience of these experts to provide 3-D 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 Ben M. Brigham, but do not have an employment agreement with any of our other employees. We have key man life insurance on Mr. Brigham in the amount of \$2 million. 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 cannot assure you that we will be successful in attracting and retaining such executives, geophysicists, geologists and engineers. See "Item 1. Business -- Technical Staff" and "Executive Officers of the Registrant."

Control By Certain Stockholders And Certain Anti-Takeover Provisions May Affect You; Certain Of Our Affiliates Control A Majority Of The Outstanding Common Stock

As of March 20, 2001, our directors, executive officers and principal stockholders, and certain of their affiliates, beneficially owned approximately 77% of our outstanding common stock. Accordingly, these stockholders, as a group, will 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 common stock will 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 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. 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.

The Market Price Of Our Stock Price Is Volatile

The trading price of our common stock and the price at which we may sell securities in the future is 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.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Management Opinion Concerning Derivative Instruments

Brigham limits its use of derivative instruments principally to commodity price hedging activities, whereby gains and losses are generally offset by price changes in the underlying commodity. Brigham's use of derivative instruments for hedging activities could materially affect its results of operations in particular quarterly or annual periods since such instruments can limit Brigham's ability to benefit from favorable oil and natural gas price movements.

Commodity Price Risk

Brigham's primary commodity market risk exposure is to changes in the prices related to the sale of its 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, Brigham employs established policies and procedures to manage its exposure to fluctuations in the sales prices it receives for its oil and natural gas production through hedging activities. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations -- Other Matters -- Derivative Instruments."

Brigham believes that hedging, although not free of risk, allows it to reduce its exposure to oil and natural gas sales price fluctuations and thereby to achieve more predictable cash flows. However, hedging arrangements, when utilized, may limit the benefit to Brigham of increases in the prices of the hedged commodity. Moreover, Brigham's hedging arrangements generally do not apply to all of its production and thus provide only partial price protection against declines in commodity prices. Brigham expects that the amount of its hedges will vary from time to time.

Interest Rate Risk

Brigham is subject to interest rate risk as borrowings under its Senior Credit Facility (\$75 million outstanding as of December 31, 2000) accrue interest at floating rates based on the lender's base rate or LIBOR. Brigham does not utilize derivative instruments to protect against changes in interest rates on debt borrowings. Based on Brigham's \$75 million of outstanding borrowings under its Senior Credit Facility at December 31, 2000, an adverse change (defined as a hypothetical 1% and 2% increase in interest rates on such borrowings) would reduce cash flow by approximately \$750,000 and \$1.5 million, respectively, from currently projected levels.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Brigham's 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.

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" and to the information under the caption "Section 16(a) Beneficial Ownership Reporting Compliance" in Brigham's definitive Proxy Statement (the "2001 Proxy Statement") for its annual meeting of stockholders to be held on May 10, 2001. The 2001 Proxy Statement will be filed with the Securities and Exchange Commission (the "Commission") not later than 120 days subsequent to December 31, 2000.

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 2001 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2000.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information required by this item is incorporated herein by reference to the 2001 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2000.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

The information required by this item is incorporated herein by reference to the 2001 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2000.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(a) 1. Consolidated Financial Statements:

See Index to Financial Statements on page F-1.

2. Financial Statement Schedules:

See Index to Financial Statements on page F-1.

3. Exhibits:

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

(b) The following reports on Form 8-K were filed by Brigham during the last quarter of the period covered by this Annual Report on Form 10-K:

Brigham filed a report on Form 8-K on November 3, 2000 (and a subsequent amendment thereto on November 8, 2000) to report a series of financing agreements.

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.

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

Bcf. One billion cubic feet.

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 of natural gas liquids.

CAEX. Computer-aided exploration.

Completion. The installation of permanent equipment for the production of oil or natural gas.

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.

Drilling Costs. The costs associated with drilling and completing a well (exclusive of seismic and land acquisition costs for that well and future development costs associated with proved undeveloped reserves added by the well) divided by total proved reserve additions.

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.

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

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

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

Mcf. One thousand cubic feet of natural gas.

Mcfe. One thousand cubic feet of natural gas equivalents.

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

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.

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

Net Production. Production that is owned by the Company 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.

Present Value of Future Net Revenues or PV10%. The pretax present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with SEC 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 aftertax present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with SEC 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%.

2-D Seismic. The method by which a cross-section of the earth's subsurface is created through the interpretation of reflecting seismic data collected along a single source profile.

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.

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.

BRIGHAM EXPLORATION COMPANY

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REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors
and Stockholders of Brigham Exploration Company

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of changes in stockholders' equity and of cash flows present fairly, in all material respects, the financial position of Brigham Exploration Company and its subsidiaries at December 31, 2000 and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000 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 auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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.

PricewaterhouseCoopers LLP

Dallas, Texas
February 23, 2001

BRIGHAM EXPLORATION COMPANY

CONSOLIDATED BALANCE SHEETS

(in thousands)

	December 31,	
	2000	1999
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 837	\$ 2,742
Accounts receivable	9,277	4,945
Other current assets	559	577
Total current assets	10,673	8,264
Oil and natural gas properties, at cost		
Unproved	41,617	40,518
Proved	162,482	138,237
Accumulated depletion	(74,609)	(66,689)
	129,490	112,066
Other property and equipment, at cost, net	1,341	1,686
Drilling advances paid	960	23
Deferred loan fees	4,338	3,481
Other noncurrent assets	109	163
	\$ 146,911	\$ 125,683
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	\$ 9,211	14,851
Accrued drilling costs	792	541
Participant advances received	136	850
Other current liabilities	7,760	1,502
Total current liabilities	17,899	17,744
Notes payable	75,000	56,000
Senior subordinated notes	7,000	41,341
Other noncurrent liabilities	3,697	1,600
Commitments and contingencies		
Mandatorily redeemable preferred stock, Series A Preferred Stock, \$.01 par value, \$20 stated value, 1.5 million shares authorized, 1 million shares issued and outstanding at December 31, 2000, redemption value of \$20 million	8,558	-
Stockholders' equity:		
Preferred stock, \$.01 par value, 10 million shares authorized, none issued and outstanding	-	-
Common stock, \$.01 par value, 50 million shares authorized, 17,030,176 and 14,517,786 issued at December 31, 2000 and 1999, respectively	170	145
Additional paid-in capital	78,274	64,171
Treasury stock, at cost; 1,052,632 shares at December 31, 2000	(3,950)	-
Unearned stock compensation	(1,321)	(290)
Accumulated deficit	(38,416)	(55,028)
Total stockholders' equity	34,757	8,998
	\$ 146,911	\$ 125,683

Oil and natural gas properties are accounted for using the full cost method.
See accompanying notes to the consolidated financial statements.

BRIGHAM EXPLORATION COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share data)

	Year Ended December 31,		
	2000	1999	1998
Revenues:			
Oil and natural gas sales	\$ 19,143	\$ 14,992	\$ 13,799
Workstation revenue	53	285	390
	<u>19,196</u>	<u>15,277</u>	<u>14,189</u>
Costs and expenses:			
Lease operating	2,139	2,259	2,172
Production taxes	1,786	968	850
General and administrative	3,100	3,481	4,672
Depletion of oil and natural gas properties	7,920	7,792	8,483
Depreciation and amortization	507	525	413
Capitalized ceiling impairment	-	-	25,926
Amortization of stock compensation	113	1	372
	<u>15,565</u>	<u>15,026</u>	<u>42,888</u>
Operating income (loss)	<u>3,631</u>	<u>251</u>	<u>(28,699)</u>
Other income (expense):			
Interest income	108	176	136
Interest expense, net	(9,906)	(9,697)	(5,968)
Loss on sale of oil and natural gas properties	-	(12,195)	-
Other expense	(9,488)	(163)	-
	<u>(19,286)</u>	<u>(21,879)</u>	<u>(5,832)</u>
Loss before income taxes and extraordinary item	(15,655)	(21,628)	(34,531)
Income tax benefit	-	-	1,186
Loss before extraordinary item	(15,655)	(21,628)	(33,345)
Extraordinary item - gain on refinancing of senior subordinated notes, net of \$0 tax	32,267	-	-
Net income (loss)	16,612	(21,628)	(33,345)
Less accretion and dividends on redeemable preferred stock	275	-	-
Net income (loss) attributable to common stockholders	<u>\$ 16,337</u>	<u>\$ (21,628)</u>	<u>\$ (33,345)</u>
Net income (loss) per share attributable to common stockholders:			
Basic/Diluted			
Loss before extraordinary item	\$ (0.98)	\$ (1.53)	\$ (2.64)
Extraordinary item	\$ 1.99	\$ -	\$ -
	<u>\$ 1.01</u>	<u>\$ (1.53)</u>	<u>\$ (2.64)</u>
Weighted average common shares outstanding:			
Basic/Diluted	<u>16,241</u>	<u>14,152</u>	<u>12,626</u>

See accompanying notes to the consolidated financial statements.

BRIGHAM EXPLORATION COMPANY

CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDERS' EQUITY

(in thousands)

	Common Stock		Additional Paid-in Capital	Unearned Stock Compensation	Accumulated Deficit	Treasury Stock		Total
	Shares	Amounts				Shares	Amounts	
Balance, December 31, 1997	12,253	\$ 123	\$ 44,919	\$ (1,674)	\$ (55)	-	\$ -	\$ 43,313
Net loss	-	-	-	-	(33,345)	-	-	(33,345)
Issuance of common stock	1,053	10	9,419	-	-	-	-	9,429
Issuance of warrants	-	-	4,500	-	-	-	-	4,500
Amortization of unearned stock compensation	-	-	-	784	-	-	-	784
Balance, December 31, 1998	13,306	133	58,838	(890)	(33,400)	-	-	24,681
Net loss	-	-	-	-	(21,628)	-	-	(21,628)
Issuance of common stock	1,212	12	4,228	-	-	-	-	4,240
Forfeiture of stock options	-	-	(602)	602	-	-	-	-
Revision in terms of warrants	-	-	479	-	-	-	-	479
Issuance of warrants	-	-	1,228	-	-	-	-	1,228
Amortization of unearned stock compensation	-	-	-	(2)	-	-	-	(2)
Balance, December 31, 1999	14,518	145	64,171	(290)	(55,028)	-	-	8,998
Net income	-	-	-	-	16,612	-	-	16,612
Issuance of common stock	2,203	22	4,185	-	-	-	-	4,207
Issuance of restricted stock	309	3	1,137	(1,140)	-	-	-	-
Issuance of stock options	-	-	185	(185)	-	-	-	-
Forfeiture of stock options	-	-	(60)	10	-	-	-	(50)
Issuance of warrants	-	-	13,910	-	-	-	-	13,910
Cancellation of warrants	-	-	(4,979)	-	-	-	-	(4,979)
Amortization of unearned stock compensation	-	-	-	284	-	-	-	284
Purchase of treasury stock	-	-	-	-	-	(1,053)	(3,950)	(3,950)
Dividends on Series A Preferred Stock	-	-	(267)	-	-	-	-	(267)
Accretion on Series A Preferred Stock	-	-	(8)	-	-	-	-	(8)
Balance, December 31, 2000	<u>17,030</u>	<u>\$ 170</u>	<u>\$ 78,274</u>	<u>\$ (1,321)</u>	<u>\$ (38,416)</u>	<u>(1,053)</u>	<u>\$(3,950)</u>	<u>\$ 34,757</u>

See accompanying notes to the consolidated financial statements.

BRIGHAM EXPLORATION COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	December 31,		
	2000	1999	1998
Cash flows from operating activities:			
Net income (loss)	\$ 16,612	\$ (21,628)	\$ (33,345)
Adjustments to reconcile net income (loss) to cash provided (used) by operating activities:			
Depletion of oil and natural gas properties	7,920	7,792	8,483
Depreciation and amortization	507	525	413
Capitalized ceiling impairment	-	-	25,926
Amortization of stock compensation	113	1	372
Interest paid through issuance of additional senior subordinated notes	4,575	5,459	-
Amortization of deferred loan fees and debt issuance costs	1,283	1,739	726
Amortization of discount on senior subordinated notes	673	575	286
Amortization of deferred loss on derivative instruments	280	759	-
Market value adjustment for derivative instruments	8,885	115	-
Extraordinary gain on refinancing of senior subordinated notes	(32,267)	-	-
Loss on sale of oil and natural gas properties	-	12,195	-
Changes in working capital and other items:			
(Increase) decrease in accounts receivable	(4,332)	2,993	(3,029)
(Increase) decrease in other current assets	(262)	(1,046)	(10)
Increase (decrease) in accounts payable	(7,290)	(1,136)	7,991
Increase (decrease) in participant advances received	(714)	86	275
Increase (decrease) in other current liabilities	(640)	(115)	862
Increase (decrease) in deferred tax liability	-	-	(1,186)
Other noncurrent assets	54	(151)	6
Other noncurrent liabilities	(32)	(5,585)	7,004
Net cash provided (used) by operating activities	<u>(4,635)</u>	<u>2,578</u>	<u>14,774</u>
Cash flows from investing activities:			
Additions to oil and natural gas properties	(28,910)	(25,560)	(85,207)
Proceeds from sale of oil and natural gas properties	3,938	27,143	-
Additions to other property and equipment	(162)	(146)	(868)
(Increase) decrease in drilling advances paid	(937)	207	(152)
Net cash provided (used) by investing activities	<u>(26,071)</u>	<u>1,644</u>	<u>(86,227)</u>
Cash flows from financing activities:			
Proceeds from issuance of common stock	4,207	-	9,429
Proceeds from issuance of preferred stock and warrants	20,060	-	-
Proceeds from issuance of senior subordinated notes and warrants	7,000	-	40,000
Increase in notes payable	19,000	13,750	105,800
Repayment of notes payable	-	(16,750)	(78,800)
Principal payments on senior subordinated notes	(20,354)	-	-
Principal payments on capital lease obligations	(210)	(253)	(236)
Deferred loan fees paid	(902)	(796)	(3,872)
Net cash provided (used) by financing activities	<u>28,801</u>	<u>(4,049)</u>	<u>72,321</u>
Net increase (decrease) in cash and cash equivalents	(1,905)	173	868
Cash and cash equivalents, beginning of year	2,742	2,569	1,701
Cash and cash equivalents, end of year	<u>\$ 837</u>	<u>\$ 2,742</u>	<u>\$ 2,569</u>

See accompanying 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 the "Company." 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 West Texas, the Anadarko Basin and the onshore Gulf Coast.

Pursuant to an exchange agreement dated February 26, 1997 (the "Exchange Agreement") and upon the initial filing on February 27, 1997 of a registration statement with the Securities and Exchange Commission (the "SEC") for the public offering of common stock (the "Offering"), the shareholders of Brigham, Inc. transferred all of the outstanding stock of Brigham, Inc. to the Company in exchange for 3,859,821 shares of common stock of the Company. Pursuant to the Exchange Agreement, the Partnership's other general partner and the limited partners also transferred all of their partnership interests to the Company in exchange for 3,314,286 shares of common stock of the Company. Furthermore, the holders of the Partnership's subordinated convertible notes transferred these notes to the Company in exchange for 1,754,464 shares of common stock. These transactions are referred to as "the Exchange." In completing the Exchange, the Company issued 8,928,571 shares of common stock to the stockholders of Brigham, Inc., the partners of the Partnership and the holder of the Partnership's subordinated notes payable. As a result of the Exchange, the Company now owns all the partnership interests in the Partnership. In May 1997, the Company sold 3,325,000 shares of its common stock in the Offering at a price of \$8.00 per share.

2. Summary of Significant Accounting Policies

Basis of Accounting

The preparation of financial statements in conformity with generally accepted accounting principles 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. Actual results may differ from those estimates.

Principles of Consolidation

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

Cash and Cash Equivalents

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

Property and Equipment

The Company uses the full cost method of accounting for oil and natural gas properties. Under this method, all acquisition, exploration and development costs, including payroll, interest, and other internal costs, 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 cost 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 costs of future development, dismantlement, restoration and abandonment costs, net of estimated salvage values, 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 valuation 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.

Other property and equipment, which primarily consists of 3-D seismic interpretation workstations, are 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

The Company recognizes oil and natural gas sales from its interests in producing wells under the sales method of accounting. Under the sales method, the Company recognizes revenues based on the amount of oil or natural gas sold to purchasers which may differ from the amounts to which the Company is entitled based on its interest in the properties. Gas balancing obligations as of December 31, 2000, 1999 and 1998 were not significant.

Industry participants in the Company's seismic programs are charged on an hourly basis for the work performed by the Company on its 3-D seismic interpretation workstations. The Company recognizes workstation revenue as service is provided.

Financial Instruments

The Company periodically enters into commodity contracts, including price swaps, caps and/or 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 natural gas or crude oil without the exchange of underlying volumes. The notional amounts of these financial instruments are based on expected production from existing wells. The Company uses these financial instruments to manage market risks resulting from fluctuations in commodity prices.

Correlation of the commodity contracts is determined by evaluating whether the contract gains and losses will substantially offset the effects of price changes on the underlying natural gas and crude oil sales volumes. To the extent that correlation exists between the contracts and the underlying natural gas and crude oil sales volumes, realized gains or losses and related cash flows arising from the contracts are recognized as a component of oil and natural gas sales in the same period as the sale of the underlying volumes. To the extent that correlation does not exist between the contracts and the underlying natural gas and crude oil sales volumes, realized gains or losses and related cash flows arising from the contracts are recognized in the period incurred as a component of other income. The fair market value of any contract that does not meet the correlation test outlined above is recorded as a deferred gain or loss on the balance sheet and is adjusted to current market value at each balance sheet date with any deferred gains or losses recognized as a component of other income.

In the event that management decides to terminate a contract, generally accepted accounting principles require that any gains or losses upon termination be deferred and recognized as oil and natural gas sales in the period in which the underlying volumes are sold.

Stock Based Compensation

The Company 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, the Company has adopted the disclosure-only provisions of Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation" ("FAS 123"). See Note 13 for the pro forma disclosures of compensation expense determined under the fair-value provisions of FAS 123.

Income Taxes

The Company follows the provisions of Financial Accounting Standard No. 109, "Accounting for Income Taxes" ("FAS 109"). Under the asset and liability method of FAS 109, 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. Under FAS 109, 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.

Segment Information

All of the Company's oil and natural gas properties and related operations are located in the United States and management has determined that the Company 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.

New Pronouncements

In June 1998, the Financial Accounting Standards Board (the "FASB") issued Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("FAS 133"). The FASB has subsequently issued Statements of Financial Accounting Standards No. 137 and 138, which are amendments to FAS 133. FAS 133, as amended, is effective for fiscal years beginning after June 15, 2000. The Company adopted FAS 133 on January 1, 2001.

FAS 133, as amended, establishes accounting and reporting standards for derivative instruments and for hedging activities. All derivative instruments will be 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. The Company's derivative contracts consist primarily of cash flow hedge transactions in which the Company is hedging the variability of cash flows related to a forecasted transaction. Changes in the fair value of these derivative instruments will be reported in other comprehensive income and will be reclassified as earnings in the periods in which earnings are impacted by the variability of the cash flows of the hedged item. The ineffective portion of all hedges will be recognized in current period earnings.

In January 2001, the Company recorded a net of tax cumulative effect adjustment of \$11.8 million to other comprehensive income to recognize the fair value (liability) of all derivative instruments which qualify for hedge accounting treatment in accordance with FAS 133.

Reclassifications

Certain reclassifications have been made to the prior year balances to conform to current year presentation.

3. Asset Dispositions

In February 1999, the Company entered into a project financing arrangement with Duke Energy Financial Services, Inc. ("Duke") to fund the continued exploration of five projects covered by approximately 200 square miles of 3-D seismic data acquired in 1998. In this transaction, the Company conveyed 100% of its working interest in land and seismic in these project areas to a newly formed limited liability company (the "Duke LLC") for a total consideration of \$10 million. The Company is the managing member of the Duke LLC with a 1% interest and Duke is the sole remaining member with a 99% interest. Pursuant to the terms of the Duke LLC agreement, the Company pays 100% of the drilling and completion costs for all wells drilled by the Duke LLC in exchange for a 70% working interest in the wells and their associated drilling and spacing units and allocable seismic data. Upon 100% project payout, the Company has certain rights to back-in for up to a 94% effective working interest in the Duke LLC properties. See Note 16 regarding dissolution of the Duke LLC in February 2001.

In June 1999, the Company sold its entire interest in certain producing and non-producing oil and natural gas properties located in its Anadarko Basin province to two parties for a combined sales price of \$17.1 million. Total proceeds, net of transaction costs, were \$16.7 million and were used to repay a portion of the Company's notes payable. Due to the magnitude of the reserve volumes that were attributable to these properties relative to the Company's remaining net reserve volumes, the Company recognized a loss of \$12.2 million, which was the difference between the sales price received, after adjustment for transaction costs, and the \$28.9 million basis allocated to the divested properties in accordance with the full-cost method of accounting for oil and natural gas properties.

4. Property and Equipment

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

	December 31,	
	2000	1999
Oil and natural gas properties.....	\$ 204,099	\$ 178,755
Accumulated depletion.....	(74,609)	(66,689)
	<u>129,490</u>	<u>112,066</u>
Other property and equipment:		
3-D seismic interpretation workstations and software.....	2,277	2,248
Office furniture and equipment.....	2,015	1,909
Accumulated depreciation.....	(2,951)	(2,471)
	<u>1,341</u>	<u>1,686</u>
	<u>\$ 130,831</u>	<u>\$ 113,752</u>

The Company 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. During the years ended December 31, 2000, 1999 and 1998, these capitalized costs amounted to \$3.4 million, \$3.3 million and \$4.6 million, respectively. Capitalized costs do not include any costs related to production, general corporate overhead, or similar activities. Interest costs of \$2.8 million, \$3.0 million and \$1.2 million were capitalized in 2000, 1999 and 1998, respectively.

5. Notes Payable and Senior Subordinated Notes Payable

Notes Payable

In January 1998, the Company entered into a reserve-based revolving credit facility (the "Credit Facility") which originally provided for initial borrowing availability of \$75 million. Principal outstanding under the Credit Facility was due at maturity on January 26, 2001 with interest due monthly for base rate tranches or periodically as LIBOR tranches mature. Amounts outstanding under the Credit Facility accrued interest at either the lender's Base Rate or LIBOR plus 2.25%, at the Company's option. In connection with the origination of the Credit Facility, certain bank fees and other expenses totaling approximately \$1.9 million were recorded as deferred costs and are amortized over the life of the loan.

The Credit Facility was amended in March 1999 to reduce the borrowing availability, extend the date of borrowing base redetermination, modify certain financial covenants, include certain additional covenants that place significant restrictions on the Company's ability to make certain capital expenditures, and to change the interest rate on outstanding borrowings to either the lender's Base Rate or LIBOR plus 3.0%, at the Company's option. The Company incurred a \$500,000 transaction fee due to the lender over a ten-month period.

In July 1999, the Credit Facility was amended to provide the Company with borrowing availability of \$56 million. As consideration for this amendment, in July 1999 the Company issued to its senior lenders one million warrants to purchase the Company's common stock at an exercise price of \$2.25 per share. An estimated value of \$1.2 million was attributed to these warrants by the Company and was recognized as additional deferred loan fees to be amortized over the remaining period to maturity of the Credit Facility. The Company's obligations under the Credit Facility are secured by substantially all of the oil and natural gas properties and other tangible assets of the Company.

In February 2000, the Company entered into an amended and restated Credit Facility with its existing senior lenders and a new senior lender. The Credit Facility was further amended in October 2000. The amended and restated Credit Facility provides the Company with \$75 million in senior borrowing availability for a three-year term. The Credit Facility includes a provision whereby certain amounts held by one of the lenders, not to exceed \$30 million of the outstanding borrowings, are convertible into shares of the Company's common stock ("Convertible Notes") to the extent total borrowings exceed \$45 million. As of December 31, 2000, the outstanding balance of the Convertible Notes totaled \$30 million.

The Credit Facility provides that the Convertible Notes can be converted into shares of the Company's common stock at the following amounts and prices: (i) the first \$10 million of borrowings is convertible at \$3.90 per share, (ii) the second \$10 million is convertible at \$6.00 per share, and (iii) the final \$10 million is convertible at \$8.00 per share. The Convertible Notes could result in a beneficial conversion feature based on the relationship between the Company's stock price at the time of a borrowing and the share price at which the Company can force conversion of the relative portion of the Convertible Notes. The value assigned to the beneficial conversion feature would be recorded as a component of interest expense to the extent the Convertible Notes are immediately convertible. Due to the fact that the Company could force conversion of any portion of the Convertible Notes before February 17, 2001, and also given that the share prices at which the Company can force conversion were in excess of the market price of the Company's common stock at each draw date since the amendment of the Credit Facility, no beneficial conversion feature was recorded in 2000. If the Credit Facility is repaid at maturity or is prepaid prior to maturity without payments of cash premiums, the warrants issued to the new participant in the Credit Facility to purchase the Company's common stock become exercisable. Further, to the extent the Company prepays any of the Convertible Notes, it will be required to pay a premium above the face value of the Convertible Notes to the lender. Such premium amounts range from 150% to 110%, depending on the timing of the prepayment. Such prepayment, however, would require the prior approval of the original lenders to the Credit Facility. In addition, certain financial covenants of the Credit Facility were amended or added in February 2000 and in October 2000. In connection with the February 2000 amendment, the Company reset the price of the warrants previously issued to two of its senior lenders to purchase one million shares of the Company's common stock from an exercise price of \$2.25 per share to \$2.02 per share.

Principal outstanding under the Credit Facility is due at maturity on December 31, 2002 with interest due monthly for base rate tranches or periodically as LIBOR tranches mature. The annual interest rate for borrowings is either the lender's base rate or LIBOR plus 3%, at the Company's option. The obligation is secured by substantially all of the Company's oil and natural gas properties and other tangible assets. At December 31, 2000, the Company had \$75 million in borrowing outstanding under the Credit Facility.

The Credit Facility has certain financial covenants, including current and interest coverage ratios, minimum current ratio, minimum interest coverage ratio, and the limitation on capital expenditures related to seismic and land activities.

Senior Subordinated Notes Payable

In August 1998, the Company issued \$50 million of debt and equity securities to two affiliated institutional investors. The financing transaction consisted of the issuance of \$40 million of senior subordinated secured notes (the "Subordinated Notes") with warrants (the "Warrants") to purchase the Company's common stock and the sale of \$10 million of the Company's common stock, or 1,052,632 shares at a price of \$9.50 per share. The combined sale of the Subordinated Notes and common stock of the Company generated proceeds, net of transaction costs, of approximately \$47.5 million that was used to repay a portion of the then outstanding borrowings under the Credit Facility.

Principal outstanding under the Subordinated Notes was due at maturity on August 20, 2003. Interest on the Subordinated Notes was payable quarterly at rates that vary depending upon whether accrued interest was paid in cash or "in kind" through the issuance of additional Subordinated Notes. Interest was payable in cash at interest rates of 12%, 13%, and 14% during the years one through three, year four and year five, respectively, of the term of the Subordinated Notes; provided, however, that the Company was permitted to pay interest in kind for a cumulative total of seven (or potentially eight) quarterly interest payments at interest rates of 13%, 14% and 15% during the years one through three, year four and year five, respectively, of the term of the Subordinated Notes. The Company was permitted to repay the Subordinated Notes in full without premium at any time prior to maturity. The indenture governing the Subordinated Notes contained certain covenants including, but not limited to, limitations or restrictions on indebtedness, distributions, affiliate transactions, liens and sale and leaseback transactions. The indenture prohibited all dividends on the Company's stock. Warrants to purchase 1 million shares of the Company's common stock exercisable during a period of seven years at a price of \$10.45 per share were issued in connection with the Subordinated Notes.

Concurrent with the issuance of the Subordinated Notes, the Company recorded a discount on the Subordinated Notes of \$4.5 million to reflect the estimated value of the Warrants. Also, in connection with the issuance of the Subordinated Notes, certain fees and expenses totaling approximately \$1.8 million were recorded as deferred costs. The Subordinated Note discount and deferred fees were amortized over the five-year term of the Subordinated Notes.

In March 1999, the indenture governing the Subordinated Notes was amended to provide the Company with the option to pay interest due on the Subordinated Notes in kind, for any reason, through the second quarter of 2000. The amendment also provided for a reduction in the exercise price per share of the Warrants from \$10.45 per share to \$3.50 per share. The discount on the Subordinated Notes was decreased by \$479,000 to reflect the change in value attributed to the Warrants as a result of the revision in the terms of the Warrants.

In February 2000, the indenture governing the Subordinated Notes was amended to, among other things, provide the Company with an extension of its right to pay interest through the issuance of additional Subordinated Notes in lieu of cash (or "in kind") through the third quarter of 2000 and potentially through the fourth quarter of 2000 if certain conditions were met. In exchange for granting these amendments, the Company (i) reset the price of the warrants previously issued to the holders of the Subordinated Notes to purchase one million shares of the Company's common stock from an exercise price of \$3.50 per share to \$2.43 per share and (ii) granted to the holders of the Subordinated Notes a term overriding royalty interest that provided for the limited right to receive 4%, or 3% if certain conditions were met, of the Company's net production revenue to reduce any outstanding Subordinated Notes issued as interest paid in kind. As payments were made pursuant to the term overriding royalty interest, they were recorded by the Company as a reduction of the balance payable pursuant to the Subordinated Notes.

On November 1, 2000, the Subordinated Notes, the term overriding royalty interest and all of the equity securities of the Company held by the holders of the Subordinated Notes were purchased by the Company for \$20 million cash resulting in an extraordinary gain of \$32.3 million, net of transaction costs of \$1.7 million.

In October 2000, the Company issued \$20 million of new subordinated notes to Shell Capital Inc. (the "SCI Notes") and 1,250,000 warrants to purchase the Company's common stock (the "SCI Warrants"). The SCI Notes bear interest at 10.75% per annum and have no principal repayment obligations until maturity in 2005. The SCI Notes are issued pursuant a multi-draw facility at borrowing increments of at least \$1 million, and such funds cannot be redrawn once they have been repaid. Interest is payable quarterly on the last day of each January, April, July and October. At the Company's option, up to 50% of the interest payments during the first two years can be satisfied by payment-in-kind ("PIK") through the issuance of additional SCI Notes in lieu of cash. The SCI Notes are secured obligations ranking

junior to the Company's existing \$75 million Credit Facility, have a five-year maturity, are redeemable at the Company's option for face value at anytime and have certain financial and other covenants. The SCI Warrants have a term of seven years, an exercise price of \$3.00 per share and a cashless exercise feature. The Company valued the SCI Warrants using the Black-Scholes valuation model and recorded the estimated value of \$2.9 million as deferred loan costs which are amortized over the five year term of the SCI Notes. As of December 31, 2000, the outstanding balance of the SCI Notes totaled \$7 million.

6. Series A Preferred Stock

On October 31, 2000, the Company issued one million shares of mandatorily redeemable preferred stock (the "Series A Preferred Stock") and 6,666,667 warrants to purchase the Company's common stock (the "Series A Warrants") for net proceeds of \$19.8 million. The proceeds from the issuance of the Series A Preferred Stock and Series A Warrants were used to purchase the Subordinated Notes, the term overriding royalty interest and all of the equity securities of the Company held by the holder of the Subordinated Notes as described in Note 5.

The Company designated 1.5 million shares of preferred stock as Series A Preferred Stock, which has a par value of \$.01 per share and a stated value of \$20 per share, in October 2000. 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. At the Company's option, up to 100% of the dividend payments on the Series A Preferred Stock can be paid by the issuance of PIK dividends until November 2005. The Series A Preferred Stock matures in November 2010 and is redeemable at the Company's option at 100% or 101% of par value (depending upon certain conditions) at anytime prior to maturity. As of December 31, 2000, the Company had one million shares of Series A Preferred Stock issued and outstanding with a \$20 million liquidation value.

The Series A Warrants have a term of ten years, an exercise price of \$3.00 per share and must be exercised, if the Company so requires, in the event the Company's common stock trades at or above \$5.00 per share for 60 consecutive trading days. The exercise price of the Series A Warrants is payable either in cash or in shares of the Series A Preferred Stock valued at liquidation value plus accrued dividends. If the Company requires exercise of the Series A Warrants, proceeds will be used to fund the redemption of a similar value of then outstanding Series A Preferred Stock. The Series A Warrants were valued at \$11.5 million using the Black-Scholes valuation model and were recorded as additional paid-in capital in the year ended December 31, 2000.

7. Issuance of Common Stock

In February 2000, the Company issued 2,195,122 shares of common stock and 731,707 warrants to purchase the Company's common stock for total net proceeds of \$4.2 million in a private placement to a group of institutional investors led by affiliates of two members of the Company's board of directors. The equity sale consisted of units that included one share of common stock and one-third of a warrant to purchase the Company's common stock at an exercise price of \$2.5625 per share.

8. Capital Lease Obligations

Property under capital leases consists of the following (in thousands):

	<u>December 31,</u>	
	<u>2000</u>	<u>1999</u>
3-D seismic interpretation workstations and software	\$ 601	\$ 607
Office furniture and equipment.....	167	167
	<u>768</u>	<u>774</u>
Accumulated depreciation and amortization	(587)	(410)
	<u>\$ 181</u>	<u>\$ 364</u>

The obligations under capital leases are at fixed interest rates ranging from 7.5% to 17.9% and are collateralized by property, plant and equipment. The future minimum lease payments under the capital leases and the present value of the net minimum lease payments at December 31, 2000 are as follows (in thousands):

2001	\$ 115
2002	27
Total minimum lease payments	<u>142</u>
Estimated executory costs included in capital leases	(7)
Net minimum lease payments.....	<u>135</u>
Amounts representing interest.....	(9)
Present value of net minimum lease payments	126
Less: current portion	<u>(102)</u>
Noncurrent portion	<u>\$ 24</u>

9. Income Taxes

The provision for income taxes consists of the following (in thousands):

	Year ended December 31,	
	2000	1999
Current income taxes:		
Federal	\$ -	\$ -
State	-	-
Deferred income taxes:		
Federal	-	-
State	-	-
	<u>\$ -</u>	<u>\$ -</u>

The difference 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,	
	2000	1999
Tax at statutory rate	\$ 5,814	\$ (7,570)
Add the effect of:		
Nondeductible expenses	12	8
Valuation allowance	(5,826)	7,562
	<u>\$ -</u>	<u>\$ -</u>

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

	December 31,	
	2000	1999
Deferred tax assets:		
Net operating loss carryforwards	\$ 26,329	\$ 18,796
Amortization of stock compensation	305	266
Derivatives	3,434	-
Other	26	27
	<u>30,094</u>	<u>19,089</u>
Deferred tax liability:		
Depreciable and depletable property	(17,578)	(484)
Valuation allowance	(12,516)	(18,605)
	<u>\$ -</u>	<u>\$ -</u>

At December 31, 2000, the Company has regular tax net operating loss carryforwards of approximately \$75.2 million of which \$13.2 million expires in 2012, \$26.4 million expires in 2018, \$22.2 expires in 2019 and \$13.4 million expires in 2020. In addition, at December 31, 2000, the Company has alternative minimum tax net operating loss carryforwards of approximately \$63.3 million of which \$8.6 million expires in 2012, \$23.2 million expires in 2018, \$21.6 million expires in 2019 and \$9.9 million expires in 2020.

10. Net Income (Loss) Per Share

The Company accounts for its earnings per share in accordance with Statement of Financial Accounting Standards No. 128, "Earnings per Share" which replaced the calculation of primary and fully diluted earnings per share with basic and diluted earning per share. Basic earnings per share is 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 the Company. The number of common share equivalents outstanding is computed using the treasury stock method.

At December 31, 2000, 1999, and 1998, options and warrants to purchase approximately 11.1 million, 3.5 million and 2.2 million shares of common stock, respectively, were outstanding but were not included in the computation of diluted income (loss) per share because the effect of including the options and warrants would have been anti-dilutive.

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

Litigation

The Company 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 the Company.

As of December 31, 2000, there were no known environmental or other regulatory matters related to the Company's operations which are reasonably expected to result in a material liability to the Company. Compliance with environmental laws and regulations has not had, and is not expected to have, a material adverse effect on the Company's capital expenditures, earnings or competitive position.

Operating Lease Commitments

The Company leases office equipment and space under operating leases expiring at various dates through 2002. The future minimum annual rental payments under the noncancelable terms of these leases at December 31, 2000 are as follows (in thousands):

2001.....	\$	790
2002.....		395
		<u>\$ 1,185</u>

Rental expense for the years ended December 31, 2000, 1999 and 1998 was approximately \$805,000, \$938,000 and \$875,000, respectively.

Major Customers

The following purchasers accounted for 10% or more of the Company's oil and natural gas sales for the years ended December 31, 2000, 1999 and 1998:

	<u>2000</u>	<u>1999</u>	<u>1998</u>
Purchaser A	36%	26%	25%
Purchaser B	20%	16%	11%
Purchaser C	-	11%	-
Purchaser D	-	-	15%
Purchaser E	-	-	11%

Due to the availability of other purchasers, the Company does not believe that the loss of any one of these individual purchasers would adversely affect the Company's result of operations.

Factors Which May Affect Future Operations

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

12. Financial Instruments

The Company periodically enters into commodity price swap agreements 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 natural gas or crude oil without the exchange of the underlying volumes. The notional amounts of these derivative financial instruments are based on planned production from existing wells. The Company uses these derivative financial instruments to manage market risks resulting from fluctuations in commodity prices. Commodity price swaps are effective in minimizing these risks by creating essentially equal and offsetting market exposures.

In February 1998, the Company entered into a hedging contract whereby 10,000 MMBtu per day of natural gas was purchased and sold subject to a fixed price swap agreement for monthly periods from April 1998 through October 1999. Pursuant to these arrangements the Company exchanged a floating market price for a contract month and payments were received when the fixed price exceeded the floating price. Total natural gas subject to this hedging contract was 3,040,000 MMBtu in 1999 and 2,750,000 MMBtu in 1998.

In August 1998, the Company entered into a hedging contract whereby 5,000 MMBtu per day of natural gas was purchased and sold subject to a fixed price swap agreement for monthly periods from April 1999 through October 1999. Pursuant to these arrangements the Company exchanged a floating market price for a fixed contract price of \$2.015 per MMBtu. Payments were made by the Company when the floating price exceeded the fixed price for a contract month and payments were received when the fixed price exceeded the floating price. Total natural gas subject to this hedging contract was 1,070,000 MMBtu in 1999.

In January 1999, the Company entered into a swap agreement with terms similar to existing agreements which related to production for monthly periods from November 1999 through March 2000. Pursuant to these arrangements, 15,000 MMBtu per day of natural gas was purchased and sold subject to a fixed price swap agreement, and the Company exchanged a floating market price for a fixed contract price of \$2.065 per MMBtu. Total natural gas volumes subject to this agreement were 1,365,000 MMBtu in 2000 and 915,000 MMBtu in 1999.

As a result of these arrangements, the Company realized an increase (decrease) in oil and natural gas revenues of approximately \$(482,000), \$(486,000), and \$555,000 for the years ending December 31, 2000, 1999, and 1998, respectively. To the extent that notional amounts covered by these arrangements exceed actual production quantities, a corresponding portion of the contracts has been recorded on the balance sheet at fair value which approximated \$0 and

\$291,000 as of December 31, 2000 and 1999, respectively. Additionally, the mark-to-market adjustments and related cash flows associated with this portion of these contracts of approximately \$291,000 and \$(429,000) have been recorded as a component of other income (expense) on the 2000 and 1999 statements of operations, respectively.

In September 1999, the Company amended the fixed contract price from \$2.065 per MMBtu to a range from \$2.509 to \$2.678 per MMBtu for natural gas volumes for the months of October 1999 through January 2000 under the then outstanding swap agreement. This resulted in a deferred loss of \$1.1 million to be amortized to oil and natural gas revenues and other income (expense) over the original contract period of October 1999 through January 2000. For the year ended December 31, 2000, approximately \$285,000 was amortized to oil and natural gas revenues and, for the year ended December 31, 1999, approximately \$645,000 was amortized to oil and natural gas revenues and approximately \$129,000 was amortized to other income.

In March 2000, the Company redesignated or replaced the 15,000 MMBtu per day swap of natural gas production with three swap agreements of 5,000 MMBtu per day for the period from April 1, 2000 through April 30, 2001 at fixed prices of \$2.065 per MMBtu, \$2.0575 per MMBtu, and \$2.15 per MMBtu. The floating prices in the replacement swap agreements represent the principal geographic markets in which the Company produces and sells the natural gas which provides a better hedge of commodity price risks. Total natural gas subject to these agreements in 2000 and 2001 are 4,125,000 MMBtu and 1,800,000 MMBtu, respectively. The Company realized a decrease in oil and natural gas revenues of \$9.4 million for the year ended December 31, 2000.

In September 1999, the Company entered into a natural gas cap contract that provides the counterparty with a call option on 10,000 MMBtu per day of natural gas production for the monthly periods from May 2001 through June 2002. Payments are made by the Company to the counterparty when the floating price exceeds the fixed price of \$2.50 per MMBtu for the periods May 2001 through October 2001 and May 2002 through June 2002, and \$2.70 per MMBtu for the period November 2001 through April 2002. These instruments do not qualify for hedge accounting and, accordingly, were recorded on the date of the transaction at their fair value of \$1.1 million as a deferred credit on the balance sheet. As of December 31, 2000 and 1999, the fair value of the remaining contracts approximated \$10.1 million and \$875,000, respectively, with the corresponding mark-to-market adjustments and related cash flows recorded as a component of other income (expense) on the statement of operations.

In March 2000, the Company entered into a combination of crude oil floor and cap options on the sale of 400 barrels per day of production for the period January 1, 2001 through June 30, 2001. Under this collar arrangement, the Company will receive a minimum price of \$18.00 per barrel and a maximum of \$26.60 per barrel. The Company concurrently established a collar on 200 barrels per day of oil production for the period July 1, 2001 through December 31, 2001. The minimum and maximum prices for this collar are \$16.10 and \$25.25 per barrel, respectively.

The Company'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 maturities. The carrying value of the Company's revolving credit facility approximates its fair market value since it bears interest at floating market interest rates.

The Company's accounts receivable relate to oil and natural gas to various industry companies, amounts due from industry participants for expenditures made by the Company on their behalf and workstation revenues. Credit terms, typical of industry standards, are of a short-term nature and the Company does not require collateral. The Company's accounts receivable at December 31, 2000 and 1999 do not represent significant credit risks as they are dispersed across many counterparties. Counterparties to the natural gas and crude oil price swaps are investment grade financial institutions.

13. Employee Benefit Plans

Retirement Savings Plan

The Company has adopted a defined contribution 401(k) plan for substantially all of its employees. Eligible employees may contribute up to 25% of their compensation to this plan. The 401(k) plan provides that the Company

may, at its discretion, match employee contributions. The Company has not matched employee contributions in any plan year.

Stock Compensation

In 1994, three employees were granted restricted interests in the Company that vested in increments through July 1999. At the date of grant, the value of these interests was immaterial. On February 26, 1997, in connection with the Exchange (see Note 1), the three employees transferred these interests to the Company in exchange for 156,250 shares of restricted common stock of the Company. The terms of the restricted stock and the restricted Company interests are substantially the same. No compensation expense resulted from this exchange.

The Company adopted an incentive plan, effective upon completion of the Exchange (see Note 1), which provides 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 reward key employees whose performance may have a significant effect on the success of the Company. An aggregate of 1,588,170 shares of the Company's common stock was reserved for issuance pursuant to this plan. 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. Options granted subsequent to March 4, 1997 have an exercise price equal to the fair market value of the Company's common stock on the date of grant and generally vest over three to five years.

The Company also maintains a plan under which it offers stock compensation to non-employee directors. Pursuant to the terms of the plan, non-employee directors are entitled to annual grants. Options granted under this plan have an exercise price equal to the fair market value of the Company's common stock on the date of grant and generally vest over five years.

The following table summarizes activity under the incentive plan for each of the three years ended December 31, 2000:

	<u>Shares</u>	<u>Weighted Average Exercise Price</u>
Options outstanding December 31, 1997	628,737	\$ 5.03
Options granted	873,500	8.62
Options forfeited or cancelled	(307,583)	(12.88)
Options exercised	-	-
Options outstanding December 31, 1998	1,194,654	5.63
Options granted	650,000	2.43
Options forfeited or cancelled	(324,761)	(4.68)
Options exercised	(167)	(7.46)
Options outstanding December 31, 1999	1,519,726	4.47
Options granted	793,500	2.83
Options forfeited or cancelled	(898,112)	(5.57)
Options exercised	(8,000)	(5.11)
Options outstanding December 31, 2000	<u>1,407,114</u>	<u>\$ 2.89</u>

The Company is required to use variable accounting for 252,500 of the stock options granted during 2000. This method of accounting requires recognition of noncash compensation expense for the difference between the option exercise price and the market price of the Company's stock at the end of the accounting period of vested options. Since the market price for the Company's stock is a component of the variable cost accounting calculation, it is not possible to determine the total noncash compensation expense that will be recognized during the vesting period of these options.

On December 14, 1998, the Board of Directors approved a proposal to cancel and reissue outstanding employee stock options that were granted in January 1998 with an exercise price of \$12.88. A total of 305,250 options with an exercise price of \$12.88 per share were cancelled and reissued with an exercise price of \$6.31 per share, the fair market value of the Company's stock at the date of reissuance. Vesting schedules remained unchanged by the reissuance.

Exercise prices for options outstanding at December 31, 2000 range from \$1.5545 to \$14.375 and have remaining contract lives of 1 to 7 years. Exercise prices for options outstanding at December 31, 1999 range from \$1.5545 to \$14.375 and remaining contractual lives range from 4.5 to 7 years. Exercise prices for options outstanding at December 31, 1998 range from \$5.00 to \$14.375 and remaining contractual lives range from 5.5 to 7 years. Exercise prices for options outstanding at December 31, 1997 range from \$5.00 to \$14.375 and remaining contractual lives range from 5.5 to 6 years. Options exercisable at December 31, 2000, 1999 and 1998 were 247,450, 291,242 and 145,740, respectively.

The weighted average fair value per share of stock compensation issued during 2000, 1999 and 1998 was \$1.92, \$1.42 and \$5.40, respectively. The fair value for these options was estimated using the Black-Scholes model with the following weighted average assumptions for grants made in 2000, 1999 and 1998: risk free interest rate of 6.2%, 6.0% and 4.7%; volatility of the expected market prices of the Company's common stock of 67%, 57% and 77%; expected dividend yield of zero and weighted average expected option lives of 6.6, 5.6 and 5.0 years, respectively.

The Black-Scholes valuation 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 the Company'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 the Company's stock options.

Had compensation cost for the Company's stock options been determined based on the fair market value at the grant dates of the awards consistent with the methodology prescribed by FAS No. 123, the Company's net income (loss) and net income (loss) per share for 2000, 1999 and 1998 would have been the pro forma amounts indicated below:

	<u>2000</u>	<u>1999</u>	<u>1998</u>
Net income (loss) (in thousands):			
As reported	\$ 16,612	\$(21,628)	\$(33,345)
Pro forma	17,744	(21,605)	(33,591)
Net income (loss) per share:			
As reported	1.01	(1.53)	(2.64)
Pro forma.....	1.09	(1.53)	(2.66)

The Company granted 644,097 stock options as of March 4, 1997. These options have an exercise price of \$5.00 compared to an originally determined estimated fair market value of the Company's common stock at date of grant of \$8.00. This grant resulted in noncash compensation expense that is being recognized over the related vesting period of the options. In January 1998, the Company revised the fair market value of its common stock at the date these options were granted from \$8.00 to \$9.00. The result of this revision was an increase in the 1997 net loss of approximately \$81,000, or \$0.01 per share.

Exchange of Certain Options for Shares of Restricted Stock

On October 25, 2000, the compensation committee of the Board of Directors approved a proposal to give its employees a one-time right to elect to cancel all or half of their outstanding employee stock options which were previously granted with exercise prices of \$5.00 per share (the "\$5 Options") or \$6.31 per share (the "\$6.31 Options") and to receive in exchange shares of restricted stock under the Company's 1997 Incentive Plan. The exchange ratios were .643 shares of restricted stock for each share of common stock underlying a \$5 Option and .4 shares of restricted stock for each share of common stock underlying a \$6.31 Option.

Pursuant to the option exchange offer, on October 27, 2000, a total of 244,794 of the \$5 Options were canceled in exchange for 157,401 shares of restricted stock, and a total of 379,665 of the \$6.31 Options were canceled in exchange for 151,866 shares of restricted stock. Regardless of whether the canceled options were vested or unvested, the shares of restricted stock vest 25% per year beginning October 27, 2000. The restricted stock agreements contain provisions for accelerated vesting in some circumstances, which provisions are similar to those in the agreements covering the canceled options. This exchange resulted in noncash compensation expense of approximately \$1.1 million that is being recognized over the vesting period of the restricted stock.

14. Related Party Transactions

During the years ended December 31, 2000, 1999 and 1998, the Company incurred costs of approximately \$138,000, \$180,000 and \$851,000, respectively, for fees for land acquisition services performed by a company owned by a brother of the Company's President and Chief Executive Officer. Other participants in the Company's 3-D seismic projects reimbursed the Company for a portion of these amounts.

A director of the Company served as a consultant to the Company on various aspects of the Company's business and strategic issues. Fees paid for these services by the Company were \$32,709, \$62,874 and \$100,539 for the years ended December 31, 2000, 1999 and 1998, respectively. Additional disbursements totaling approximately \$12,000, \$12,000 and \$12,000 were made during 2000, 1999 and 1998, respectively, for the reimbursement of certain expenses.

15. Supplemental Cash Flow Information

	<u>2000</u>	<u>1999</u>	<u>1998</u>
Cash paid for interest	\$ 3,894	\$ 1,960	\$ 5,490
Noncash investing and financing activities:			
Capital lease asset additions	\$ -	\$ 51	\$ 320
Decrease in accounts payable and other noncurrent liabilities in exchange for issuance of common stock	-	4,240	-
Increase in accounts payable for deferred loan fees to be paid in future.....	-	50	-
Increase in deferred loan fees for issuance of warrants.....	2,400	1,228	-
Dividends and accretion on mandatorily redeemable preferred stock	275	-	-

16. Subsequent Events

Duke Project

In February 2001, Duke, as majority member of the Duke LLC (as described in Note 3) elected to dissolve the Duke LLC. As a result, the remaining undeveloped land and seismic data in the Duke LLC project areas will be unconditionally owned by Duke following the dissolution of the Duke LLC.

Preferred Stock Placement

In March 2001, the Company issued 500,000 shares of Series A Preferred Stock and 2,105,263 warrants to purchase the Company's common stock (the "Additional Series A Warrants") for \$10 million. The Series A Preferred Stock, which is mandatorily redeemable, is described in Note 6.

The Additional Series A Warrants have terms similar to the Series A Warrants described in Note 6 except the Additional Series A Warrants have an exercise price of \$4.75 per share and must be exercised, if the Company so requires, in the event that the Company's common stock trades at an average of at least 150% of the exercise price (currently \$7.125 per share) for 60 consecutive trading days. The Additional Series A Warrants are valued at approximately \$4.5 million using the Black-Scholes valuation model and were recorded as additional paid-in capital in March 2001.

17. Oil and Natural Gas Exploration and Production Activities

The tables presented below provide supplemental information about oil and natural gas exploration and production activities as defined by SFAS No. 69, "Disclosures about Oil and Gas Producing Activities".

Results of Operations for Oil and Natural Gas Producing Activities (in thousands)

	Year ended December 31,		
	2000	1999	1998
Oil and natural gas sales	\$ 19,143	\$ 14,992	\$ 13,799
Costs and expenses:			
Lease operating	2,139	2,259	2,172
Production taxes	1,786	968	850
Depletion of oil and natural gas properties.....	7,920	7,792	8,483
Capitalized ceiling impairment.....	-	-	25,926
Income tax expense (benefit) (a)	2,554	1,391	(8,271)
Total costs and expenses.....	<u>14,399</u>	<u>12,410</u>	<u>29,160</u>
	<u>\$ 4,744</u>	<u>\$ 2,582</u>	<u>\$(15,361)</u>
Depletion per physical unit of production (equivalent Mcf of gas)	<u>\$ 1.20</u>	<u>\$ 1.24</u>	<u>\$ 1.27</u>

- (a) The income tax expense (benefit) is calculated at the statutory rate and determined without regard to the Company's deduction for general and administrative expenses, interest costs and other income tax deductions and credits.

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,		
	2000	1999	1998
Costs incurred for the year:			
Exploration.....	\$ 14,238	\$ 19,224	\$ 68,214
Property acquisition.....	2,540	3,462	16,245
Development	12,555	4,632	10,475
Proceeds from participants	(40)	(2,439)	(10,502)
	<u>\$ 29,293</u>	<u>\$ 24,879</u>	<u>\$ 84,432</u>

Costs incurred represent amounts incurred by the Company for exploration, property acquisition and development activities. Periodically, the Company will receive proceeds from participants subsequent to project initiation for an assignment of an interest in the project. These payments are represented by "Proceeds from participants" in the table above.

Capitalized costs related to oil and natural gas acquisition, exploration and development activities follow (in thousands):

	December 31,	
	2000	1999
Cost of oil and natural gas properties at year-end:		
Proved	\$ 162,482	\$ 138,237
Unproved	41,617	40,518
Total capitalized costs	204,099	178,755
Accumulated depletion	(74,609)	(66,689)
	<u>\$ 129,490</u>	<u>\$ 112,066</u>

Following is a summary of costs (in thousands) excluded from depletion at December 31, 2000 by year incurred. At this time, the Company is unable to predict either the timing of the inclusion of these costs and the related natural gas and oil reserves in its depletion computation or their potential future impact on depletion rates.

	December 31,			Prior Years	Total
	2000	1999	1998		
Property acquisition	\$ 1,126	\$ 933	\$ 4,000	\$ 7,396	\$ 13,455
Exploration	595	1,015	13,107	8,480	23,197
Capitalized interest	2,772	1,951	242	-	4,965
Total	<u>\$ 4,493</u>	<u>\$ 3,899</u>	<u>\$ 17,349</u>	<u>\$ 15,876</u>	<u>\$ 41,617</u>

18. Oil and Natural Gas Reserves and Related Financial Data (Unaudited)

Information with respect to the Company'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 the Company's independent petroleum consultants and internal petroleum reservoir engineer.

Oil and Natural Gas Reserve Data

The following tables present the Company's estimates of its proved oil and natural gas reserves. The Company emphasizes that reserve estimates 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. Accordingly, there can be no assurance that the reserves set forth herein will ultimately be produced nor can there be assurance that the proved undeveloped reserves will be developed within the periods anticipated. A substantial portion of the reserve balances was estimated utilizing the volumetric method, as opposed to the production performance method.

	Natural Gas (MMcf)	Oil (MBbls)
Proved reserves at December 31, 1997	53,230	3,181
Revisions to previous estimates	(26,696)	(115)
Extensions, discoveries and other additions	48,050	1,752
Purchase of minerals-in-place	851	11
Production	<u>(4,269)</u>	<u>(396)</u>
Proved reserves at December 31, 1998	71,166	4,433
Revisions to previous estimates	(9,938)	214
Extensions, discoveries and other additions	30,428	1,156
Sales of minerals-in-place	(22,002)	(2,430)
Production	<u>(4,197)</u>	<u>(346)</u>
Proved reserves at December 31, 1999	65,457	3,027
Revisions of previous estimates	83	(554)
Extensions, discoveries and other additions	17,058	758
Production	<u>(4,431)</u>	<u>(361)</u>
Proved reserves at December 31, 2000	<u>78,167</u>	<u>2,870</u>
Proved developed reserves at December 31:		
1998	38,571	2,935
1999	28,594	1,873
2000	30,754	1,620

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 the Company'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 the Company's oil and natural gas reserves.

	December 31,		
	2000	1999	1998
Future cash inflows	\$ 899,819	\$ 228,429	\$ 198,082
Future development and production costs	(154,295)	(61,878)	(61,064)
Future income taxes	<u>(216,342)</u>	<u>(12,406)</u>	<u>(6,972)</u>
Future net cash inflows	<u>\$ 529,182</u>	<u>\$ 154,145</u>	<u>\$ 130,046</u>
Future net cash inflow before income taxes, discounted at 10% per annum.....	\$ 497,666	\$ 114,466	\$ 81,741
Standardized measure of future net cash inflows discounted at 10% per annum.....	<u>\$ 359,228</u>	<u>\$ 113,546</u>	<u>\$ 81,649</u>

The base sales prices for the Company's reserves were \$10.42 per Mcf for natural gas and \$26.83 per Bbl for oil as of December 31, 2000, \$2.35 per Mcf for natural gas and \$22.75 per Bbl for oil as of December 31, 1999, and \$2.12 per Mcf for natural gas and \$9.50 per Bbl for oil as of December 31, 1998. 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 the Company's reserves at these dates.

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

	December 31,		
	2000	1999	1998
Beginning of period.....	\$113,546	\$ 81,649	\$ 64,274
Sales of oil and natural gas produced, net of production costs	(15,218)	(11,765)	(10,776)
Development costs incurred.....	5,308	4,413	5,423
Extensions and discoveries	295,239	43,346	52,389
Purchases of minerals-in-place.....	-	-	687
Sales of minerals-in-place	-	(32,783)	-
Net change of prices and production costs.....	175,018	33,226	(11,921)
Change in future development costs.....	6,990	(555)	(656)
Changes in production rates and other	(83,322)	637	(6,109)
Revisions of quantity estimates	(12,262)	(11,969)	(23,470)
Accretion of discount	11,447	8,174	6,925
Change in income taxes	(137,518)	(827)	4,883
End of period	<u>\$359,228</u>	<u>\$113,546</u>	<u>\$ 81,649</u>

19. Quarterly Financial Data (Unaudited)

	Year Ended December 31, 2000			
	Quarter 1	Quarter 2	Quarter 3	Quarter 4
Revenue.....	\$ 4,538	\$ 4,651	\$ 5,365	\$ 4,642
Operating income	1,136	1,078	1,198	219
Net loss before extraordinary gain.....	(2,198)	(4,328)	(5,345)	(3,784)
Extraordinary gain.....	-	-	-	32,267
Net income (loss)	(2,198)	(4,328)	(5,345)	28,208
Net loss per share:				
Basic/Diluted				
Net loss before extraordinary gain	(0.14)	(0.26)	(0.32)	(0.25)
Extraordinary gain	-	-	-	1.99

	Year Ended December 31, 1999			
	Quarter 1	Quarter 2	Quarter 3	Quarter 4
Revenue.....	\$ 3,281	\$ 3,624	\$ 4,238	\$ 4,134
Operating income (loss)	113	190	(432)	380
Net loss.....	(1,944)	(14,839)	(2,651)	(2,194)
Net loss per share:				
Basic/Diluted	(0.15)	(1.04)	(0.18)	(0.15)

CORPORATE INFORMATION

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Fax: 512.427.3400

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IR E-Mail: investor@bexp3d.com
HR E-Mail: hr@bexp3d.com

Independent Auditors

PricewaterhouseCoopers LLP
Dallas, 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
40 Wall Street, 46th Floor
New York, New York 10005
Phone: 800.937.5449

Board of Directors (left to right)
Top row: Harold D. Carter, Stephen P.
Reynolds, Alexis M. Cranberg,
and Ben M. Brigham,
Sitting: Anne L. Brigham, Curtis F.
Harrell, and Steven A. Webster.



Annual Shareholders Meeting

Brigham Exploration Company will hold its annual meeting of shareholders at 1:00 pm on May 10, 2001 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 investor@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 MarketSM 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.

OFFICERS & DIRECTORS

Ben "Bud" M. Brigham

President, Chief Executive Officer and
Chairman of the Board

Curtis F. Harrell

Executive Vice President,
Chief Financial Officer and Director

Jeffery E. Larson

Senior Vice President - Exploration

A. Lance Langford

Senior Vice President - Operations

David T. Brigham

Senior Vice President - Land and Administration
Corporate Secretary

Karen E. Lynch

Vice President - Legal and General Counsel

Anne L. Brigham

Director
Former Executive Vice President of Brigham
Exploration Company

Harold D. Carter

Director and Consultant
Former President and Chief Operating
Officer of Sabine Corporation

Alexis M. Cranberg

Director
President of Aspect Management Corporation

Stephen P. Reynolds

Director
Special Advisor to General Atlantic
Partners, LLC

Steven A. Webster

Director
Managing Director of Global Energy Partners



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