HOUSTON EXPLORATION CO
Form 10-Q
August 13, 2002

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

FORM 10-Q

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

FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2002

OR

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

FOR THE TRANSITION PERIOD FROM -------- TO --------

COMMISSION FILE NO. 001-11899

THE HOUSTON EXPLORATION COMPANY
(EXACT NAME OF REGISTRANT AS SPECIFIED IN ITS CHARTER)

DELAWARE	22-2674487
(STATE OR OTHER JURISDICTION OF INCORPORATION OR ORGANIZATION)	(IRS EMPLOYER IDENTIFICATION NO.)

1100 LOUISIANA STREET, SUITE 2001
HOUSTON, TEXAS 77002-5215
(ADDRESS OF PRINCIPAL EXECUTIVE OFFICES AND ZIP CODE)
(713) 830-6800
(REGISTRANT'S TELEPHONE NUMBER, INCLUDING AREA CODE)

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 X No

As of August 12, 2002, 30,526,391 shares of Common Stock, par value $.01 per share, were outstanding.

THE HOUSTON EXPLORATION COMPANY

TABLE OF CONTENTS

FACTORS AFFECTING FORWARD LOOKING STATEMENTS

All of the estimates and assumptions contained in this Quarterly Report and in the documents we have incorporated by reference into this Quarterly Report constitute forward looking statements as that term is defined in Section 27A of the Securities Act of 1993 and Section 21E of the Securities Exchange Act of 1934. These forward-looking statements generally are accompanied by words such as "anticipate," "believe," "expect," "estimate," "project" or similar expressions. All statements under the caption "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" relating to our anticipated capital expenditures, future cash flows and borrowings, pursuit of potential future acquisition opportunities and sources of funding for exploration and development are forward looking statements. Although we believe that these forward-looking statements are based on reasonable assumptions, our expectations may not occur and we cannot guarantee that the anticipated future results will be achieved. A number of factors could cause our actual future results to differ materially from the anticipated future results expressed in this Quarterly Report. These factors include, among other things, the volatility of natural gas and oil prices, the requirement to take write downs if natural gas and oil prices decline, our ability to meet our substantial capital requirements, our substantial outstanding indebtedness, the uncertainty of estimates of natural gas and oil reserves and production rates, our ability to replace reserves, and our hedging activities. For additional discussion of these risks, uncertainties and assumptions, see "Items 1 and 2. Business and Properties" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" contained in our Annual Report on Form 10K.

In this Quarterly Report, unless the context requires otherwise, when we refer to "we", "us" or "our", we are describing The Houston Exploration Company and its subsidiary on a consolidated basis.

PART I. FINANCIAL INFORMATION

ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

THE HOUSTON EXPLORATION COMPANY
CONSOLIDATED BALANCE SHEETS
(IN THOUSANDS, EXCEPT SHARE DATA)

	JUNE 30 2002 (UNAUDIT
ASSETS:	
Cash and cash equivalents	$ 23,
Accounts receivable	56,
Accounts receivable -- Affiliate	
Derivative financial instruments	3,
Inventories	1,
Prepayments and other	
Total current assets	86,
Natural gas and oil properties, full cost method	
Unevaluated properties	139,
Properties subject to amortization	1,661,
Other property and equipment	9,
	1,810,
Less: Accumulated depreciation, depletion and amortization	(822,
	987,
Other assets	5,

TOTAL ASSETS	$ 1,078,
LIABILITIES:	
Accounts payable and accrued expenses	$ 62,
Total current liabilities	62,
Long-term debt and notes	280,
Derivative financial instruments	4,
Deferred federal income taxes	168,
Other deferred liabilities	
TOTAL LIABILITIES	517,
COMMITMENTS AND CONTINGENCIES (SEE NOTE 3)	
STOCKHOLDERS' EQUITY:	
Common Stock, $.01 par value, 50,000,000 shares authorized and 30,526,141 shares issued and outstanding at June 30, 2002 and 30,463,230 shares issued and outstanding at December 31, 2001, respectively	
Additional paid-in capital	338,
Unearned compensation	(
Retained earnings	224,
Accumulated other comprehensive income	(
TOTAL STOCKHOLDERS' EQUITY	561,
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 1,078,

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

THE HOUSTON EXPLORATION COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
(IN THOUSANDS, EXCEPT PER SHARE DATA)

	THREE MONTHS ENDED JUNE 30, 2002	2001	SIX MONTHS ENDE 2002
	(UNAUDITED)		(UNAUDIT
REVENUES:			
Natural gas and oil revenues	$ 83,361	$ 98,916	$ 155,807
Other	367	392	561
Total revenues	83,728	99,308	156,368

OPERATING EXPENSES:			
Lease operating	7,886	6,759	15,299
Severance tax	2,791	3,015	4,483
Depreciation, depletion and amortization	42,044	30,044	81,848
General and administrative, net	2,488	2,614	5,828
Total operating expenses	55,209	42,432	107,458
Income from operations	28,519	56,876	48,910
Other expense	--	1,500	--
Interest expense, net	1,644	543	3,054
Income before income taxes	26,875	54,833	45,856
Provision for federal income taxes	9,221	18,978	15,668
NET INCOME	$ 17,654	$ 35,855	$ 30,188
Net income per share -- basic	$ 0.58	$ 1.19	$ 0.99
Net income per share -- fully diluted	$ 0.57	$ 1.17	$ 0.98
Weighted average shares outstanding	30,516	30,165	30,501
Weighted average shares outstanding fully diluted	30,854	30,554	30,846

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

THE HOUSTON EXPLORATION COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(IN THOUSANDS)

	SIX MONTHS ENDED JUNE	
	2002	200
	(UNAUDITED)	
OPERATING ACTIVITIES:		
Net income	$ 30,188	$ 83
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	81,848	60
Deferred income tax expense	16,041	46
Stock compensation expense	42	
Changes in operating assets and liabilities:		
(Increase) decrease in accounts receivable	(13,093)	48
Increase in inventories	(365)	
Decrease (increase) in prepayments and other	2,827	

Decrease (increase) in other assets	4,125	(1
Decrease in accounts payable and accrued expenses	(14,098)	(19
Increase (decrease) in other liabilities	458	
Net cash provided by operating activities	107,973	218
INVESTING ACTIVITIES:		
Investment in property and equipment	(130,935)	(146
Dispositions	261	
Net cash used in investing activities	(130,674)	(146
FINANCING ACTIVITIES:		
Proceeds from long term borrowings	46,000	67
Repayments of long term borrowings	(10,000)	(152
Proceeds from issuance of common stock	1,180	8
Net cash used in financing activities	37,180	(76
Increase (decrease) in cash and cash equivalents	14,479	(5
Cash and cash equivalents, beginning of period	8,619	9
Cash and cash equivalents, end of period	$ 23,098	$ 3
Cash paid for interest	$ 6,911	$ 8
Cash paid for taxes	$ --	$

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

6

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

NOTE 1 -- SUMMARY OF ORGANIZATION AND SIGNIFICANT ACCOUNTING POLICIES

Organization

We are an independent natural gas and oil company engaged in the exploration, development, exploitation and acquisition of domestic natural gas and oil properties. Our operations are focused offshore in the Gulf of Mexico and onshore in South Texas, the Arkoma Basin of Oklahoma and Arkansas, South Louisiana, the Appalachian Basin in West Virginia and East Texas. Our strategy is to utilize our technical expertise to continue to increase reserves, production and cash flows through the application of a three-pronged approach that combines a mix of:

- high potential offshore exploration and exploitation;
- lower risk exploitation and development drilling onshore; and
- selective acquisitions both offshore and onshore

At December 31, 2001, our net proved reserves were 608 billion cubic feet equivalent or Bcfe, with a present value, discounted at 10% per annum, of cash flows before income taxes of $714 million. Our reserves are fully engineered on an annual basis by two independent petroleum engineering companies. Our focus is natural gas. Approximately 93% of our net proved reserves at December 31, 2001 were natural gas of which approximately 74% of our net proved reserves were classified as proved developed. We operate approximately 85% of our properties.

We began exploring for natural gas and oil in December 1985 on behalf of The Brooklyn Union Gas Company. Brooklyn Union is an indirect wholly owned subsidiary of KeySpan Corporation. KeySpan, a member of the Standard & Poor's 500 Index, is a diversified energy provider whose principal natural gas distribution and electric generation operations are located in the Northeastern United States. In September 1996 we completed our initial public offering and sold approximately 34% of our shares to the public with KeySpan retaining the balance. As of June 30, 2002, THEC Holdings Corp., an indirect wholly owned subsidiary of KeySpan, owned approximately 67% of the outstanding shares of our common stock.

Principles of Consolidation

The consolidated financial statements include the accounts of The Houston Exploration Company and its wholly owned subsidiary, Seneca Upshur Petroleum Company (collectively the "Company"). All significant intercompany balances and transactions have been eliminated.

Interim Financial Statements

Our balance sheet at June 30, 2002 and the statements of operations and cash flows for the periods indicated herein have been prepared without audit, pursuant to the rules and regulations of the Securities and Exchange Commission. Certain information and footnote disclosures normally included in financial statements prepared in accordance with generally accepted accounting principles have been condensed or omitted, although we believe that the disclosures contained herein are adequate to make the information presented not misleading. The balance sheet at December 31, 2001 is derived from the December 31, 2001 audited financial statements, but does not include all disclosures required by generally accepted accounting principles. The Interim Financial Statements should be read in conjunction with the Consolidated Financial Statements and Notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2001.

In the opinion of our management, all adjustments, consisting of normal recurring accruals, necessary to present fairly the information in the accompanying financial statements have been included. The results of operations for such interim periods are not necessarily indicative of the results for the full year.

Reclassifications and Use of Estimates

The preparation of the consolidated financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

liabilities and disclosure of contingent assets and liabilities at the dates of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Our most significant financial estimates are based on remaining proved natural gas and oil reserves. Estimates of proved reserves are key components of our depletion rate for natural gas and oil properties and our full cost ceiling test limitation. Certain reclassifications of prior year items have been made to conform with current year presentation.

New Accounting Pronouncements

Statement of Financial Accounting Standards ("SFAS") No. 143, "Accounting for Asset Retirement Obligations," addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS No. 143 will be effective for us January 1, 2003 and early adoption is encouraged. SFAS No. 143 requires that the fair value of a liability for an asset's retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. Currently, we include estimated future costs of abandonment and dismantlement in our full cost amortization base and amortize these costs as a component of our depletion expense. We are evaluating the impact the new standard will have on our financial statements and at this time cannot reasonably estimate the effect of the adoption of this statement.

In April 2002 the Financial Accounting Standards Board ("FASB") issued SFAS No. 145, "Rescission of FASB Statements No. 4, No. 44, and No. 64, Amendment to FASB Statement No. 13 and Technical Corrections." SFAS No. 145 streamlines the reporting of debt extinguishments and requires that only gains and losses from extinguishments meeting the criteria in Accounting Policies Board Opinion 30 would be classified as extraordinary. Thus, gains or losses arising from extinguishments that are part of a company's recurring operations would not be reported as an extraordinary item. SFAS No. 145 is effective for fiscal years beginning after May 15, 2002 with earlier adoption encouraged. We do not expect the adoption of SFAS No. 145 to have a material impact on our financial position, results of operations or cash flows.

SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities" was issued in June 2002 and addresses accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging Issues Task Force ("EITF") Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." SFAS No. 146 requires that a liability for a cost associated with an exit or disposal activity be recognized when the liability is incurred. Under Issue 94-3, a liability for an exit cost was recognized at the date of an entity's commitment to an exit plan. Under SFAS No. 146, the objective for initial measurement of the liability is fair value. SFAS No. 146 is effective for exit or disposal activities that are initiated after December 31, 2002, with early application encouraged. We do not expect that the adoption of SFAS No. 146 to have a material impact on our financial position, results of operations or cash flows.

Hedging Contracts

We utilize derivative commodity instruments to hedge future sales prices on a portion of our natural gas production in order to achieve a more predictable cash flow and to reduce our exposure to adverse price fluctuations. We do not hold derivatives for trading purposes. While the use of hedging arrangements limits the downside risk of adverse price movements, it also limits increases in future revenues from possible favorable price movements. Hedging instruments that we use include swaps, costless collars and options, which we generally place with major financial institutions that we believe are minimal credit risks. Our hedging strategies meet the criteria for hedge accounting treatment under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities". Accordingly, we mark-to-market our derivative instruments at the end of each quarter, and defer the effective portion of the gain or loss on the change in fair value of our derivatives in Accumulated Other Comprehensive Income, a component of Stockholders' Equity. We recognize gains and losses when the underlying transaction is completed, at which time these gains and losses are reclassified from Accumulated Other Comprehensive Income and included in earnings as a component of natural gas revenues in accordance with the underlying hedged transaction. If hedging instruments

cease to meet the criteria for deferred recognition or became ineffective as defined by SFAS 133, any gains or losses would be currently recognized in earnings.

At June 30, 2002, we estimated, using the New York Mercantile Exchange, or NYMEX, index price strip as of that date that the fair market value of our derivative instruments was a negative $1.2 million. As a result, our balance sheet at June 30, 2002 reflects an asset of $3.8 million, representing the current portion of our hedge position (for months July 2002 through June 2003) and a liability of $5.0 million, representing the long-term portion (for months July 2003 through December 2003) of our hedge position with a corresponding credit of $773,000 (net of related deferred taxes of $416,000) in accumulated other comprehensive income, representing the fair market value of our total deferred hedge loss, net of tax.

At December 31, 2001, we estimated, using the NYMEX index price strip as of that date that the fair market value of our derivative instruments was a positive $53.8 million. As a result, our balance sheet at December 31, 2001 reflected an asset of $53.8 million with a corresponding credit of $34.9 million (net of related deferred taxes of $18.9 million) in accumulated other comprehensive income, representing the fair market value of our deferred hedge gain.

Net Income Per Share

Basic earnings per share ("EPS") is calculated by dividing net income by the weighted average number of shares of common stock outstanding during the period. No dilution for any potentially dilutive securities is included. Diluted EPS assumes the conversion of all potentially dilutive securities and is calculated by dividing net income, as adjusted, by the weighted average number of shares of common stock outstanding plus all potentially dilutive securities.

	THREE MONTHS ENDED JUNE 30,		SIX MONTHS EN[DED] JUNE 30,	
	2002	2001	2002	
	(in thousands, except per share data)			
Net income	$ 17,654	$ 35,855	$ 30,188	$
Weighted average shares outstanding	30,516	30,165	30,501	
Add dilutive securities:				
Options	338	389	345	
Total weighted average shares outstanding and dilutive securities	30,854	30,554	30,846	
Net income per share	$ 0.58	$ 1.19	$ 0.99	$
Net income per share - fully diluted	$ 0.57	$ 1.17	$ 0.98	$

9

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

Comprehensive Income

The table below summarizes our Comprehensive Income for the three month and six month periods ended June 30, 2002 and 2001.

	THREE MONTHS ENDED JUNE 30,		S
	2002	2001	200
	(in thousands)		
Net income	$ 17,654	$ 35,855	$ 30
Other comprehensive income, net of taxes:			
Unrealized gain (loss) on derivative instruments	(2,157)	25,382	(35
Comprehensive income	$ 15,497	$ 61,237	$ (5

NOTE 2 -- LONG-TERM DEBT AND NOTES

	JUNE 30, 2002	DECEMBER 31, 2001
	(in thousands)	
SENIOR DEBT:		
Bank revolving credit facility, due July 2005....	$ 180,000	$ 144,000
SUBORDINATED DEBT:		
8 5/8% Senior Subordinated Notes, due January 2008..................................	100,000	100,000
Total long-term debt and notes.............	$ 280,000	$ 244,000

The carrying amount of borrowings outstanding under the revolving bank credit facility approximates fair value as the interest rates are tied to current market rates. At June 30, 2002, the quoted market value of the Company's $100 million of 8 5/8% Senior Subordinated Notes was 102.9% of the $100 million carrying value or $102.9 million.

Credit Facility

New Credit Facility. We entered into a new revolving bank credit facility dated as of July 15, 2002 with a syndicate of lenders led by Wachovia Bank, National Association, as issuing bank and administrative agent, The Bank of Nova Scotia and Fleet National Bank as co-syndication agents and BNP Paribas as documentation agent. The new credit facility replaces our previous $250 million revolving credit facility maintained with JPMorgan Chase and provides us with an initial commitment of $300 million. The initial commitment can be increased at our request and with prior approval from Wachovia to a maximum of $350 million by adding one or more lenders or by allowing one or more lenders to increase their commitments. The new credit facility is subject to borrowing base limitations, and our initial borrowing base has been set at $300 million and will be redetermined semi-annually with the first redetermination scheduled for October 1, 2002. Up to $25 million of the borrowing base is available for the issuance of letters of credit. The new credit facility matures July 15, 2005, is unsecured and ranks senior to all existing debt. Following the closing of the new credit facility on July 18, 2002, funds were drawn on the new facility and used to repay total outstanding borrowings under the previous credit facility of $170 million. Subsequently, we repaid $10 million in borrowings under the new facility and as of August 12, 2002, $160 million was outstanding under the new credit facility and $0.4 million was outstanding in letter of credit obligations.

Interest is payable on borrowings under the new credit facility, as follows:

o on base rate loans, at a fluctuating rate, or base rate, equal to the sum of (a) the greater of the Federal funds rate plus .5% or Wachovia's prime rate plus (b) a variable margin between 0% and 0.50%, depending on the amount of borrowings outstanding under the credit facility, or

- on fixed rate loans, a fixed rate equal to the sum of (a) a quoted LIBOR rate divided by one minus the average maximum rate during the interest period set for certain reserves of member banks of the Federal Reserve System in Dallas, Texas plus (b) a variable margin between 1.25% and 2.00%, depending on the amount of borrowings outstanding under the credit facility.

Interest is payable on base rate loans on the last day of each calendar quarter. Interest on fixed rate loans is generally payable on maturity or at least every 90 days if the term of the loan exceeds three months. In addition to interest, we must pay a quarterly commitment fee of between 0.30% and 0.50% per annum on the unused portion of the borrowing base.

The new credit facility contains negative covenants that place restrictions and limits on, among other things, the incurrence of debt, guaranties, liens, leases and certain investments. The new credit facility also restricts and limits our ability to make cash dividends, to purchase or redeem our stock and to sell or encumber our assets. Financial covenants require us to, among other things:

- maintain a ratio of earnings before interest, taxes, depreciation, depletion and amortization (EBITDA) to cash interest payments of at least 3.00 to 1.00;

- maintain a ratio of total debt to EBITDA of not more than 3.50 to 1.00; and

- not hedge more than 70% of our natural gas production during any 12-month period.

As of the July 18, 2002, the closing date of the new credit facility, we were in compliance with all covenants.

Previous Credit Facility. We maintained our previous revolving bank credit facility with a syndicate of lenders led by JPMorgan Chase, National Association. The credit facility, as amended, provided a maximum commitment of $250 million, subject to borrowing base limitations. At June 30, 2002, the borrowing base amount was $250 million. Up to $2.0 million of the borrowing base was available for the issuance of letters. The credit facility was due to mature on April 15, 2003 and was unsecured. At June 30, 2002, $180 million was outstanding under the credit facility and $0.4 million was outstanding in letter of credit obligations. Subsequent to June 30, 2002 and prior to entering the new facility on July 15, 2002, we reduced our net borrowings by $10 million under the previous credit facility.

Our previous revolving bank credit facility contained negative covenants that placed restrictions on, among other things, the incurrence of debt, guaranties, liens, leases and certain investments. Cash dividends and/or purchase or redemption of our stock was restricted as well as the sale or encumbering of our oil and gas assets or the pledging of our oil and gas assets. Financial covenants set limits on natural gas hedging and required us to maintain specified interest coverage and debt to equity ratios. As of June 30, 2002, we were in compliance with all covenants and restrictions under the previous revolving bank credit facility.

Senior Subordinated Notes

On March 2, 1998, we issued $100 million of 8?% senior subordinated notes due January 1, 2008. The notes bear interest at a rate of 8?% per annum with interest payable semi-annually on January 1 and July 1. We may redeem the notes at our option, in whole or in part, at any time on or after January 1, 2003 at a price equal to 100% of the principal amount plus accrued and unpaid interest, if any, plus a specified premium which decreases yearly from 4.313% in 2003 to 0% after January 1, 2006 if the notes are redeemed prior to January 1, 2006. Upon the occurrence of a change of control, we will be required to offer to purchase the notes at a purchase price equal to 101% of the aggregate principal amount, plus accrued and unpaid interest, if any. A "change of control" is:

- the direct or indirect acquisition by any person, other than KeySpan or its affiliates, of beneficial ownership of 35% or more of total voting power as long as KeySpan and its affiliates own less than the acquiring person;
- the sale, lease, transfer, conveyance or other disposition, other than by way of merger or consolidation, in one or a series of related transactions, of all or substantially all of our assets to a third party other than KeySpan or its affiliates;
- the adoption of a plan relating to our liquidation or dissolution; or
- if, during any period of two consecutive years, individuals who at the beginning of this period constituted our board of directors, including any new directors who were approved by a majority vote of the stockholders, cease for any reason to constitute a majority of the members then in office.

The notes are general unsecured obligations and rank subordinate in right of payment to all existing and future senior debt, including the credit facility, and will rank senior or equal in right of payment to all existing and future subordinated indebtedness.

NOTE 3 -- COMMITMENTS AND CONTINGENCIES

We are involved from time to time in various claims and lawsuits incidental to our business. In the opinion of management, the ultimate liability, if any, will not have a material adverse effect on our financial position or results of operations.

NOTE 4 -- RELATED PARTY TRANSACTIONS

KeySpan Joint Venture

Effective January 1, 1999, we entered into a joint exploration agreement with KeySpan Exploration & Production, LLC, a subsidiary of KeySpan, to explore for natural gas and oil over an initial two-year term expiring December 31, 2000. Under the terms of the joint venture, we contributed all of our then undeveloped offshore acreage to the joint venture and we agreed that KeySpan would receive 45% of our working interest in all prospects drilled under the program. KeySpan paid 100% of actual intangible drilling costs for the joint venture up to a specified maximum of $7.7 million in 2000 and $20.7 million during 1999. Further, KeySpan paid 51.75% of all additional intangible drilling costs incurred and we paid 48.25%. Revenues are shared 55% Houston Exploration and 45% to KeySpan. In addition, we received reimbursements from KeySpan for a portion of our general and administrative costs.

Effective December 31, 2000, KeySpan and Houston Exploration agreed to end the primary or exploratory term of the joint venture. As a result, KeySpan has not participated in any of our offshore exploration prospects unless the project involved the development or further exploitation of discoveries made during the initial term of the joint venture. In addition, effective with the termination of the exploratory term of the joint venture, we have not received any further reimbursement from KeySpan for general and administrative costs.

During the initial two-year term of the joint venture, we drilled a total of 21 wells: 17 exploratory wells and four development wells. Five of the wells drilled were unsuccessful. During 2001, KeySpan participated in the drilling of three additional wells, all of which were successful. These wells further developed or delineated reservoirs discovered during the initial term of the joint venture. For 2002, KeySpan has committed to a capital budget of $15 million for development projects associated with its working interests in wells drilled under the joint venture during 1999, 2000 and 2001. During the first half 2002, KeySpan participated in three wells, all of which were successful and provided further exploitation of previous discoveries, and spent $14.6 million in capital costs compared to $10.1 million spent during the first half of 2001. For the second quarter of 2002, KeySpan spent $5.1 million in capital costs compared to $7.4 million spent during the corresponding quarter of 2001.

NOTE 5 -- ACQUISITION

Burlington Acquisition

On May 30, 2002, we completed the purchase of natural gas and oil producing properties and associated gathering pipelines, together with undeveloped acreage, from Burlington Resources Inc. located in the Webb, Jim Hogg, Wharton and Calhoun counties of South Texas. The properties purchased cover approximately 24,800 gross (10,800 net) acres located in the North East Thompsonville, South Laredo, McFarlan and Maude Traylor Fields. The properties purchased represent interests in approximately 145 producing wells and total proved reserves of 42 Bcfe as of January 1, 2002, the effective date of the transaction. Our average working interest is 35% and we are the operator of approximately 23% of the producing wells acquired. The $44.5 million purchase price, which is net of a purchase price adjustment of $3.9 million, was financed by borrowings under our revolving bank credit facility. Production from the acquired properties for the month of June 2002 averaged 14 MMcfe/day, net to the interests acquired.

On July 16, 2002, we sold those interests acquired from Burlington in the McFarlan and Maude Traylor Fields for approximately $5.0 million, which was net of a purchase price adjustment of $1.1 million. The effective date of this transaction was January 1, 2002. These two fields, located in Wharton and Calhoun counties, respectively, are outside our current area of focus in South

Texas. The sale represents interests in 22 producing wells with reserves of approximately 5 Bcfe and average daily production of 2 Mcfe/day, net to our interest. Proceeds from the sale were used to repay borrowings under our new revolving bank credit facility.

We expect to retain the North East Thompsonville Field, located in Jim Hogg County, and the South Laredo Field, located in Webb County. The North East Thompsonville Field has 10 wells producing from the Wilcox formation, all of which we operate, and representing approximately 70% of the proved reserves and 75% of the current production associated with the acquisition from Burlington. The South Laredo Field, located in Webb County and in the Lobo Trend, contains 113 wells, all operated by a third party.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion is intended to assist in an understanding of our historical financial position and results of operations for the three months ended June 30, 2002 and 2001. Our consolidated financial statements and notes thereto included elsewhere in this report contains detailed information that should be referred to in conjunction with the following discussion.

GENERAL

We are an independent natural gas and oil company engaged in the exploration, development, exploitation and acquisition of domestic natural gas and oil properties. Our operations are focused offshore in the Gulf of Mexico and onshore in South Texas, the Arkoma Basin of Oklahoma and Arkansas, South Louisiana, the Appalachian Basin in West Virginia and East Texas. Our strategy is to utilize our technical expertise to continue to increase reserves, production and cash flows through the application of a three-pronged approach that combines a mix of:

- high potential offshore exploration and exploitation;
- lower risk exploitation and development drilling onshore; and
- selective acquisitions both offshore and onshore.

At December 31, 2001, our net proved reserves were 608 billion cubic feet equivalent or Bcfe, with a present value, discounted at 10% per annum, of cash flows before income taxes of $714 million. Our reserves are fully engineered on an annual basis by two independent petroleum engineering companies. Our focus is natural gas. Approximately 93% of our net proved reserves at December 31, 2001 were natural gas of which approximately 74% of our net proved reserves were classified as proved developed. We operate approximately 85% of our properties.

We began exploring for natural gas and oil in December 1985 on behalf of The Brooklyn Union Gas Company. Brooklyn Union is an indirect wholly owned subsidiary of KeySpan Corporation. KeySpan, a member of the Standard & Poor's 500 Index, is a diversified energy provider whose principal natural gas distribution and electric generation operations are located in the Northeastern United States. In September 1996 we completed our initial public offering and sold approximately 34% of our shares to the public with KeySpan retaining the balance. As of June 30, 2002, THEC Holdings Corp., an indirect wholly owned subsidiary of KeySpan, owned approximately 67% of the outstanding shares of our common stock.

As an independent oil and gas producer, our revenue, profitability and future rate of growth are substantially dependent upon prevailing prices for natural gas and oil, our ability to find and produce natural gas and oil and our ability to control and reduce costs, all of which are dependent upon numerous factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. The energy markets have historically been very volatile, as evidenced by the recent volatility of natural gas and oil prices, and commodity prices may fluctuate widely in the future. A substantial or extended decline in natural gas and oil prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of natural gas and oil reserves that may be economically produced and access to capital.

Critical Accounting Policies and Use of Estimates

Full Cost Accounting. We use the full cost method to account for our natural gas and oil properties. Under full cost accounting, all costs incurred in the acquisition, exploration and development of natural gas and oil reserves are capitalized into a "full cost pool". Capitalized costs include costs of all unproved properties, internal costs directly related to our natural gas and oil activities and capitalized interest. We amortize these costs using a unit-of-production method. We compute the provision for depreciation, depletion and amortization quarterly by multiplying production for the quarter by a depletion rate. The depletion rate is determined by dividing our total unamortized cost base by net equivalent proved reserves at the beginning of the quarter. Unevaluated properties and related costs are excluded from our amortization base until we have made a determination as to the existence of proved reserves. Our amortization base includes estimates for future development costs as well as future abandonment and dismantlement costs. Sales of natural gas and oil properties are accounted for as adjustments to the full cost pool, with no gain or loss recognized, unless the adjustment would significantly alter the relationship between capitalized costs and proved reserves.

14

Under full cost accounting rules, total capitalized costs are limited to a ceiling of the present value of future net revenues, discounted at 10% per annum, plus the lower of cost or fair value of unproved properties less income tax effects (the "ceiling limitation"). We perform a quarterly ceiling test to evaluate whether the net book value of our full cost pool exceeds the ceiling limitation. If capitalized costs (net of accumulated depreciation, depletion and amortization) less deferred taxes are greater than the discounted future net revenues or ceiling limitation, a writedown or impairment of the full cost pool is required. A writedown of the carrying value of the full cost pool is a non-cash charge that reduces earnings and impacts stockholders' equity in the period of occurrence and typically results in lower depreciation, depletion and amortization expense in future periods. Once incurred, a writedown is not reversible at a later date.

The ceiling test is calculated using natural gas and oil prices in effect as of the balance sheet date, held constant over the life of the reserves. We use derivative financial instruments that qualify for hedge accounting under Statement of Financial Accounting Standards ("SFAS") No. 133 to hedge against the volatility of natural gas prices, and in accordance with current Securities and Exchange Commission guidelines, we include estimated future cash flows from our hedging program in our ceiling test calculation. In calculating our ceiling test at June 30, 2002, we estimated that we had a full cost ceiling "cushion", whereby the carrying value of our full cost pool was less than the ceiling limitation. No writedown is required when a cushion exists. Natural gas prices continue to be volatile and the risk that we will be required to write down our full cost pool increases when natural gas prices are depressed or if we have significant downward revisions in our estimated proved reserves.

Use of Estimates. The preparation of the consolidated financial statements in conformity with generally accepted accounting principles requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the dates of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Our most significant financial estimates are based on remaining proved natural gas and oil reserves. Estimates of proved reserves are key components of our depletion rate for natural gas and oil properties and our full cost ceiling test limitation.

Natural gas and oil reserve quantities represent estimates only. Under full cost accounting, we use reserve estimates to determine our full cost ceiling limitation as well as our depletion rate. We estimate our proved reserves and future net revenues using sales prices estimated to be in effect as of the date we make the reserve estimates. We hold the estimates constant throughout the life of the properties, except to the extent a contract specifically provides for escalation. Natural gas prices, which have fluctuated widely in recent years, affect estimated quantities of proved reserves and future net revenues. Further, any estimates of natural gas and oil reserves and their values are inherently uncertain, including many factors beyond our control. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil 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 geological interpretation and judgment. In addition, estimates of reserves may be revised based upon actual production, results of future development and exploration activities, prevailing natural gas and oil prices, operating costs and other factors, which revision may be material. Reserve estimates are highly dependent upon the accuracy of the underlying assumptions. Actual future production may be materially different from estimated reserve quantities and the differences could materially affect future amortization of natural gas and oil properties.

Concentration of Credit Risk. Substantially all of our accounts receivable result from natural gas and oil sales or joint interest billings to third parties in the energy industry. This concentration of customers and joint interest owners may impact our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. Historically, we have not experienced credit losses on our receivables; however, recent market conditions resulting in downgrades to credit ratings of energy marketers have affected the liquidity of several of our purchasers. We estimate that our current receivable exposure for June and July natural gas and oil sales is approximately $1.0 million from subsidiaries of Williams Companies, Inc., $2.4 million from subsidiaries of Reliant Energy Incorporated (which is due at the end of August 2002) and $0.4 million from Dynegy Inc. As of August 1, 2002, we are no longer selling natural gas and oil to Williams, Reliant and Dynegy. Based on the current demand for natural gas and oil, we do not expect that termination of sales to these companies will limit our ability to sell our production at favorable market prices.

Further, our natural gas futures and swap contracts also expose us to credit risk in the event of nonperformance by counterparties. Generally, these contracts are with major investment grade financial institutions and historically we have not experienced credit losses. In July 2002, our outstanding swap and option contracts with Williams were assigned to Bank of America. We believe that the credit risk related to the natural gas futures and swap contracts is no greater than the risk associated with the primary contracts and that the elimination of price risk lowers our overall business risk.

New Accounting Pronouncements

Statement of Financial Accounting Standards ("SFAS") No. 143, "Accounting for Asset Retirement Obligations," addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS No. 143 will be effective for us January 1, 2003 and early adoption is encouraged. SFAS No. 143 requires that the fair value of a liability for an asset's retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. Currently, we include estimated future costs of abandonment and dismantlement in our full cost amortization base and amortize these costs as a component of our depletion expense. We are evaluating the impact the new standard will have on our financial statements and at this time we cannot reasonably estimate the effect of the adoption of this statement.

In April 2002 the Financial Accounting Standards Board ("FASB") issued SFAS No. 145, "Rescission of FASB Statements No. 4, No. 44, and No. 64, Amendment to FASB Statement No. 13 and Technical Corrections." SFAS No. 145 streamlines the reporting of debt extinguishments and requires that only gains and losses from extinguishments meeting the criteria in Accounting Policies Board Opinion 30 would be classified as extraordinary. Thus, gains or losses arising from extinguishments that are part of a company's recurring operations would not be reported as an extraordinary item. SFAS No. 145 is effective for fiscal years beginning after May 15, 2002 with earlier adoption encouraged. We do not expect the adoption of SFAS No. 145 to have a material impact on our financial position, results of operations or cash flows.

SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities" was issued in June 2002 and addresses accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging Issues Task Force ("EITF") Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." SFAS No. 146 requires that a liability for a cost associated with an exit or disposal activity be recognized when the liability is incurred. Under Issue 94-3, a liability for an exit cost was recognized at the date of an entity's commitment to an exit plan. Under SFAS No 146, fair value is the objective for initial measurement of the liability. SFAS No. 146 is effective for exit or disposal activities that are initiated after December 31, 2002, with early application encouraged. We do not expect the adoption of SFAS No. 146 to have a material impact on our financial position, results of operations or cash flows.

The FASB is currently considering numerous proposals for the adoption of new accounting pronouncements. We cannot predict whether any of these proposals will be adopted, and if adopted, what effect these proposals, including the proposal to require the reporting of stock options grants as a compensation expense, may have on our financial statements.

Recent Acquisitions

Within the last six months, we have expanded our existing operations in South Texas with two producing property acquisitions: (i) the Conoco Acquisition, completed December 31, 2001, and (ii) the Burlington Acquisition, completed May 30, 2002.

Conoco Acquisition. On December 31, 2001, we completed the purchase from Conoco Inc. of natural gas and oil properties and associated gathering pipelines and equipment, together with developed and undeveloped acreage, located in the Webb and Zapata counties of South Texas. The $69 million cash purchase price was financed by borrowings under our revolving bank credit facility. The properties purchased cover approximately 25,274 gross (16,885 net) acres located in the Alexander, Haynes, Hubbard and South Trevino Fields, which are in close proximity to our existing operations in the Charco Field, and represent interests in approximately 159 producing wells. We operate approximately 95% of the producing wells we acquired. Our average working interest is 87%. Total net proved reserves as of January 1, 2002 were 80 Bcfe. Beginning January 1, 2002, we initiated an active drilling and workover program. To date we spud 18 development wells, with 15 wells successfully completed and currently producing, one dry hole and two in progress. Average daily production has increased from approximately 19 MMcfe/day, net to the interests acquired, in January 2002 to 32 MMcfe/day, net to our interests, in June 2002. Currently we have two drilling rigs under contract, which we plan to keep utilized for the remainder of 2002.

Burlington Acquisition. On May 30, 2002, we completed the purchase of natural gas and oil producing properties and associated gathering pipelines, together with undeveloped acreage, from Burlington Resources Inc. located in the Webb, Jim Hogg, Wharton and Calhoun counties of South Texas. The properties purchased cover approximately 24,800 gross (10,800 net) acres located in the North East Thompsonville, South Laredo, McFarlan and Maude Traylor Fields. The properties purchased represent interests in approximately 145 producing wells and total proved reserves of 42 Bcfe as of January 1, 2002, the effective date of the transaction. Our average working interest is 35% and we are the operator of approximately 23% of the producing wells acquired. The $44.5 million purchase price, which is net of a purchase price adjustment of $3.9 million, was financed by borrowings under our revolving bank credit facility. Current production from the acquired properties for the month of June 2002 is averaging 14.0 MMcfe/day, net to the interests acquired.

On July 16, 2002, we sold those interests acquired from Burlington in the McFarlan and Maude Traylor Fields for approximately $5.0 million, which was net of a purchase price adjustment of $1.1 million as the effective date of the transaction was January 1, 2002. These fields, located in Wharton and Calhoun counties, respectively, are outside our current area of focus in South Texas. The sale represents interests in 22 producing wells with reserves of approximately 5 Bcfe and average daily production of 2 Mcfe/day, net to our interest. Proceeds from the sale were used to repay borrowings under our revolving bank credit facility.

We expect to retain the North East Thompsonville Field, located in Jim Hogg County, and the South Laredo Field, located in Webb County. The North East Thompsonville Field has 10 wells producing wells from the Wilcox formation, all of which we operate, and represents approximately 70% of the proved reserves and 75% of the current production associated with the acquisition. The South Laredo Field, located in Webb County and in the Lobo Trend, contains 113 wells, all operated by a third party.

New Credit Facility

We entered into a new revolving bank credit facility dated as of July 15, 2002 with a syndicate of lenders led by Wachovia Bank, National Association, as issuing bank and administrative agent, The Bank of Nova Scotia and Fleet National Bank as co-syndication agents and BNP Paribas as documentation agent. The new credit facility replaces our previous $250 million revolving credit facility maintained with JPMorgan Chase and provides us with an initial commitment of $300 million. The initial commitment can be increased at our request and with prior approval from Wachovia to a maximum of $350 million by adding one or more lenders or by allowing one or more lenders to increase their commitments. The new credit facility is subject to borrowing base limitations, and our initial borrowing base has been set at $300 million and will be redetermined semi-annually with the first redetermination scheduled for October 1, 2002. Up to $25 million of the borrowing base is available for the issuance of letters of credit. The new credit facility matures July 15, 2005, is unsecured and ranks senior to all existing debt. Following the closing of the new credit facility on July 18, 2002, funds were drawn on the new

facility and used to repay total outstanding borrowings under the previous credit facility of $170 million. Subsequently, we repaid $10 million under the new facility and as of August 12, 2002, $160 million was outstanding under the new credit facility and $0.4 million was outstanding in letter of credit obligations.

Offshore Seismic Option Agreement

In June 2002, we entered into a seismic option agreement with Union Oil Company of California ("Unocal"). The agreement provides us with the ability to review seismic data that we have acquired for the purposes of delineating new exploratory prospects in the Gulf of Mexico. The agreement covers approximately 16 blocks on the Outer Continental Shelf that are currently held under lease by Unocal. The Unocal leases are in close proximity to our existing fields and acreage. Under the terms of the agreement, Unocal will have the right to participate with up to a 50% working interest in any prospects we recommend for drilling. Should Unocal elect to participate in an initial test well, we would serve as operator. If Unocal elects not to participate in an initial test well, they would farmout their interest to us. The seismic review period expires between June 15, 2002 and November 1, 2002, depending on the geographic area, and Unocal has until January 1, 2003 to elect to participate or farmout their interests in any prospects we recommend for drilling.

RESULTS OF OPERATIONS

The following table sets forth our historical natural gas and oil production data during the periods indicated:

	THREE MONTHS ENDED JUNE 30,	SIX MONTH JUNE

	2002	2001	2002
PRODUCTION:			
Natural gas (MMcf)	24,450	21,295	48,345
Oil (MBbls)	222	99	382
Total (MMcfe)	25,782	21,889	50,637
Average daily production (MMcfe/day)	283	241	280
AVERAGE SALES PRICES:			
Natural gas (per Mcf) realized(1)	$ 3.19	$ 4.54	$ 3.05
Natural gas (per Mcf) unhedged	3.19	4.48	2.70
Oil (per Bbl)	24.04	23.29	22.05
OPERATING EXPENSES (PER MCFE):			
Lease operating	$ 0.31	$ 0.31	$ 0.30
Severance tax	0.11	0.14	0.09
Depreciation, depletion and amortization	1.63	1.37	1.62
General and administrative, net(2)	0.10	0.12	0.12

----

(1) Reflects the effects of hedging.

(2) For the six months ended June 30, 2001, net general and administrative expense includes one-time payments totaling $5.2 million in connection with the termination of employment contracts for retiring executives.

RECENT FINANCIAL AND OPERATING RESULTS

COMPARISON OF THREE MONTHS ENDED JUNE 30, 2002 AND 2001

Production. Our production increased 18% from 21,889 million cubic feet equivalent, or MMcfe, for the three months ended June 30, 2001 to 25,782 MMcfe for the three months ended June 30, 2002. The increase in production was primarily attributable to production from two recently completed acquisitions in South Texas combined with newly developed offshore production brought on-line since the end of the first half of 2001.

Onshore, our daily production rates increased 26% from an average of 118 MMcfe/day during the second quarter of 2001 to an average of 149 MMcfe/day during the corresponding three months of 2002. The onshore production increase is primarily attributable to newly acquired production from the South Texas properties purchased from Conoco Inc. on December 31, 2001, which accounts for 29 MMcfe/day of the increase, and from the properties purchased on May 30, 2002 from Burlington Resources, which accounts for 5 MMcfe/day of the increase for the quarter. Production at our Charco Field remained unchanged at 82 MMcfe/day during both the second quarter of 2002 and the second quarter of 2001. Production from our Arkoma, East Texas and West Virginia fields remained unchanged at approximately 26 MMcfe/day. Production in South Louisiana decreased by 3 MMcfe/day from 10 MMcfe/day during the second quarter of 2001 to 7 MMcfe/day during the second quarter of 2002.

Offshore, our production increased 9% from an average of 123 MMcfe/day during the second quarter of 2001 to an average of 134 MMcfe/day during the second quarter of 2002. This increase is primarily attributable to new natural gas production at South March Island 253 and High Island 39, both of which came on-line during the second half of 2001, successful recompletion of four existing wells at Mustang Island 785 during the third quarter of 2001, combined with new oil production at Vermilion 408, which came on-line during January 2002 and new natural gas production at East Cameron 81 with new wells coming on-line during both the first and second quarters of 2002.

Natural Gas and Oil Revenues. Natural gas and oil revenues decreased 16% from $98.9 million for the second quarter of 2001 to $83.4 million for the second quarter of 2002 as a result of a 30% decrease in average realized natural gas prices, from $4.54 per Mcf during the second quarter of 2001 to $3.19 per Mcf in the second quarter of 2002, offset in part by an 18% increase in production for the same period.

Natural Gas Prices. For the second quarter of 2002, we realized an average gas price of $3.19 per Mcf that was equal to our average unhedged natural gas price. Natural gas and oil revenues for the second quarter of 2002 were $12,000 higher than the revenues we would have achieved if hedges had not been in place during the period. For the corresponding period during 2001, we realized an average gas price of $4.54 per Mcf, which was 101% of the average unhedged natural gas price of $4.48 that otherwise would have been received, resulting in natural gas and oil revenues that were $1.3 million higher than the revenues we would have achieved if hedges had not been in place during the period.

Lease Operating Expenses and Severance Tax. Lease operating expenses increased 16% from $6.8 million for the three months ended June 30, 2001 to $7.9 million for the corresponding three months of 2002. On an Mcfe basis, lease operating expenses were unchanged at $0.31 per Mcfe during both the second quarter of 2001 and the second quarter of 2002. The increase in lease operating expenses is attributable to the continued expansion of our operations both onshore and offshore. Onshore operations expanded with the acquisition of approximately 305 new producing wells in South Texas with the December 31, 2001 acquisition from Conoco and the May 30, 2002 acquisition from Burlington Resources. Offshore, we added new production facilities since the second half of 2001 at High Island 39, Vermilion 408 and East Cameron 81. The flat rate of $0.31 per Mcfe is a result of the 18% increase in production volume for the second quarter of 2002. Severance tax, which is a function of volume and revenues generated from onshore production, decreased 7% from $3.0 million for the second quarter of 2001 to $2.8 million for the second quarter of 2002. On an Mcfe basis, severance tax decreased 21% from $0.14 per Mcfe for the second quarter of 2001 to $0.11 per Mcfe during the second quarter of 2002. The decrease in severance tax expense and severance tax per Mcfe is primarily attributable to lower natural gas prices received during the second quarter of 2002 offset only in part by the increase in our onshore production during the current year.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased 40% from $30.0 million for the three months ended June 30, 2001 to $42.0 million for the three months ended June 30, 2002. Depreciation, depletion and amortization expense per Mcfe increased 19% from $1.37 for the three months ended June 30, 2001 to $1.63 for the corresponding three months in 2002. The increase in depreciation, depletion and amortization expense was a result of higher production volumes combined with a higher depletion rate. The higher depletion rate during the second quarter of 2002 is a result of higher finding and development costs together with the addition of fewer new reserves from exploration and developmental drilling. We believe that higher finding costs are being experienced across the industry, particularly for companies our size whose primary area of exploration is the Outer Continental Shelf or the shallow waters of the Gulf of Mexico. Because the Outer Continental

Shelf is a mature producing area, it is becoming increasingly more difficult to find and develop new reserves at historical costs.

General and Administrative Expenses, Net of Capitalized General and Administrative Expenses and Overhead Reimbursements. General and administrative expenses, net of overhead reimbursements received from other working interest owners of $0.3 million for both the three months ended June 30, 2001 and 2002 and capitalized general and administrative expenses directly related to oil and gas exploration and development activities of $2.5 million and $3.1 million for the three months ended June 30, 2001 and 2002, respectively, decreased 4% from $2.6 million for the three months ended June 30, 2001 to $2.5 million for the three months ended June 30, 2002. We capitalized more general and administrative expense during the second quarter of 2002 as a result of an increase in aggregate general and administrative expenses. Aggregate general and administrative expenses increased 7% from $5.5 million for the second quarter of 2001 to $5.9 million for the second quarter of 2002. The increase in aggregate expense is primarily a result of the expansion of our workforce and office space in Houston during the first half of 2002 combined with an increase in employee benefit expenses, legal and consulting fees.

On an Mcfe basis, net general and administrative expenses decreased 17% from $0.12 during the second

quarter of 2001 to $0.10 per Mcfe during the second quarter of 2002. The lower rate per Mcfe during the second quarter of 2002 reflects the 18% increase in production for the second quarter of 2002 together with the 4% decrease in net general and administrative expenses.

Other Income and Expense - Strategic Review Expenses. We recognized no other income or expense during the second quarter of 2002, however, for the second quarter of 2001, we paid additional expenses of $1.5 million incurred in connection with the review of strategic alternatives for our company which was initiated at the end of the third quarter of 1999. In September 1999, together with KeySpan, our majority stockholder, we had announced our intention to review strategic alternatives for our company and KeySpan's investment in our company. KeySpan was assessing our role within its future strategic plan, and was considering a full range of strategic transactions including the possible sale of all or a portion of our assets. On February 25, 2000, we announced, together with KeySpan, that the review of strategic alternatives for Houston Exploration had been completed.

KeySpan currently holds approximately 67% of our outstanding common stock. As KeySpan has announced in the past, they do not consider the businesses contained in their energy investments segment, including their investment in Houston Exploration, a part of their core asset group. KeySpan has stated in the past that they may sell or otherwise dispose of all or a portion of their non-core assets, but cannot predict when, or if, any such sale or disposition may take place.

During the first quarter of 2000, we established a reserve for strategic review expenses of $1.8 million. At March 31, 2001, we reevaluated the established reserve and felt that a portion of the reserve was no longer required. As a result of this reevaluation, during the first quarter of 2001, we recognized $1.4 million in other income relating to the reversal of a portion of the reserve. As noted above, the reserve was ultimately required. The net effect of the first quarter 2001 reversal of $1.4 million and the second quarter payment and recognition of $1.5 million in additional expenses is $119,000 in additional strategic review expenses for the six months ended June 30, 2001.

Interest Expense, Net of Capitalized Interest. Interest expense, net of capitalized interest, increased 220% from $0.5 million for the three months ended June 30, 2001 to $1.6 million for the corresponding three months of 2002. The increase in net interest expense is a direct result of a decrease in capitalized interest during the second quarter of 2002 as aggregate interest expense was unchanged at $3.6 million during both the second quarter of 2001 and the second quarter of 2002. Capitalized interest decreased 35% from $3.1 million for the second quarter of 2001 to $2.0 million for the second quarter of 2002 and corresponds to the a decrease in exploratory drilling during the second quarter of 2002 (our capitalized interest is a function of exploratory drilling and unevaluated properties, both of which were at lower levels during the second quarter of 2002). Aggregate interest is unchanged due to a combination of higher average borrowings of $261 million for the second quarter of 2002 compared to $183 million during the second quarter of 2001 and lower average interest rates of 5.28% during the second quarter of 2002 compared to 6.16% during the second quarter of 2001.

Income Tax Provision. The provision for income taxes decreased 52% from $19.0 million for the second quarter of 2001 to $9.2 million for the corresponding three months of 2002 due to the 51% decrease in pre-tax income during the second quarter of 2002 from $54.8 million during the second quarter of 2001 to $26.9 million during the second quarter of 2002 as a result of lower natural gas revenues combined with both an increase in operating and interest expenses.

Operating Income and Net Income. For the three months ended June 30, 2002, operating income decreased 50% from $56.9 million during the second quarter of 2001 to $28.5 million during the second quarter of 2002 as a result of a 16% decrease in total revenues caused by a 30% decrease in realized natural gas prices offset only in part by an 18% increase in production, combined with a 30% increase in operating expenses. Corresponding to the decrease in operating income, net income decreased 51% from $35.9 million for the second quarter of 2001 to $17.7 million for the second quarter of 2002 and includes the effects of higher interest expense and lower taxes.

COMPARISON OF SIX MONTHS ENDED JUNE 30, 2002 AND 2001

Production. Our production increased 13% from 44,656 million cubic feet equivalent, or MMcfe, for the six months ended June 30, 2001 to 50,637 MMcfe for the six months ended June 30, 2002. The increase in production was primarily attributable to newly acquired onshore production pursuant to our two South Texas producing property acquisitions made since December 31, 2001 together with newly developed offshore production brought on-line since the end of the first half of 2001.

Onshore, our daily production rates increased 20% from an average of 122 MMcfe/day during the first half of 2001 to an average of 146 MMcfe/day during the corresponding six months of 2002. Properties acquired from Conoco Inc. on December 31, 2001 accounted for an increase of 24 MMcfe/day for 2002 and properties acquired on May 30, 2002 from Burlington Resources accounted for an increase of 3 MMcfe/day for the six month period. Production from our Charco Field in South Texas decreased slightly by 2% or 2 MMcfe/day from 87 MMcfe/day during the first half of 2001 to 85 MMcfe/day during the first half of 2002. Production from all other onshore areas (Arkoma, East Texas, West Virginia and South Louisiana) decreased slightly from an average of 35 MMcfe/day during the first half of 2001 to 34 MMcfe/day during the corresponding period of 2002.

Offshore, our production increased 7% from an average of 125 MMcfe/day during the first half of 2001 to an average of 134 MMcfe/day during the first half of 2002. This increase is primarily attributable to new natural gas production at South March Island 253 and High Island 39, both of which came on-line during the second half of 2001, combined with new oil production at Vermilion 408, which came on-line during January 2002 and new natural gas production from East Cameron 81 with new wells coming on-line during both the first and second quarters of 2002.

Natural Gas and Oil Revenues. Natural gas and oil revenues decreased 30% from $222.9 million for the first six months of 2001 to $155.8 million for the first six months of 2002 as a result of a 39% decrease in average realized natural gas prices, from $5.02 per Mcf during the first half of 2001 to $3.05 per Mcf in the first half of 2002, offset in part by a 13% increase in production for the same period.

Natural Gas Prices. As a result of hedging activities, we realized an average gas price of $3.05 per Mcf for the six months ended June 30, 2002, which was 113% of the average unhedged natural gas price of $2.70 that otherwise would have been received, resulting in natural gas and oil revenues for the six months ended June 30, 2002 that were $17.0 million higher than the revenues we would have achieved if hedges had not been in place during the period. For the corresponding period during 2001, we realized an average gas price of $5.02 per Mcf, which was 88% of the average unhedged natural gas price of $5.69 that otherwise would have been received, resulting in natural gas and oil revenues that were $29.2 million lower than the revenues we would have achieved if hedges had not been in place during the period.

Lease Operating Expenses and Severance Tax. Lease operating expenses increased 18% from $13.0 million for the six months ended June 30, 2001 to $15.3 million for the corresponding six months of 2002. On an Mcfe basis, lease operating expenses increased from $0.29 per Mcfe during the first half of 2001 to $0.30 per Mcfe during the first half of 2002. The increase in both lease operating expenses and lease operating expense on a per unit basis for 2002 is attributable to the continued expansion of our operations both onshore and offshore as we acquired approximately 305 producing wells in South Texas since the beginning of 2002 and we added new offshore production facilities since the second half of 2001. Severance tax, which is a function of volume and revenues generated from onshore production, decreased 42% from $7.7 million for the first six months of 2001 to $4.5 million for the corresponding period of 2002. On an Mcfe basis, severance tax decreased from $0.17 per Mcfe for the first half of 2001 to $0.09 per Mcfe during the first half of 2002. The decrease in severance tax expense and severance tax per Mcfe is primarily due to lower natural gas prices received during the first six months of 2002 as compared to prices received during the first six months of 2001 offset only in part by the increase in onshore production during the first half of 2002.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased 36% from $60.3 million for the six months ended June 30, 2001 to $81.8 million for the six months ended June 30, 2002. Depreciation, depletion and amortization expense per Mcfe increased 20% from $1.35 for the six months ended June 30, 2001 to $1.62 for the corresponding six month period of 2002. The increase in depreciation,

depletion and amortization expense was a result of higher production volumes combined with a higher depletion rate. The higher depletion rate during the first half of 2002 is a result of higher finding and development costs incurred during 2002 together with the addition of fewer new reserves from exploration and developmental drilling. We believe that higher finding costs are being experienced across the industry, particularly for companies our size whose primary area of exploration is the Outer Continental Shelf or the shallow waters of the Gulf of Mexico. Because the Outer Continental Shelf is a mature producing area, it is becoming increasingly more difficult to find and develop new reserves at historical costs.

General and Administrative Expenses, Net of Capitalized General and Administrative Expenses and Overhead Reimbursements. General and administrative expenses, net of overhead reimbursements received from other working interest owners of $0.6 million and $0.9 million for the six months ended June 30, 2001 and 2002, respectively, and capitalized general and administrative expenses directly related to oil and gas exploration and development activities of $7.4 million and $6.4 million, respectively, for the six months ended June 30, 2001 and 2002, decreased 45% from $10.6 million for the six months ended June 30, 2001 to $5.8 million for the six months ended June 30, 2002. Included in general and administrative expense for the first half of 2001 were payments totaling $5.2 million made in connection with the termination of former executive officers' employment contracts.

Excluding the one-time charges taken for the termination of employment contracts totaling $5.2 million during the first half of 2001, aggregate general and administrative expenses would have been $13.4 million for the first half of 2001 compared to $13.1 million for the first half of 2002, reflecting a small decrease of 2% for the current six month period which was due primarily to a decrease in incentive compensation expense during 2002 as the first half of 2001 included the payment of a special bonus in January 2001. Excluding these same one-time charges of $5.2 million during the first half of 2001, net general and administrative expenses would have been $5.4 million during the first six months of 2001 compared to $5.8 million for the corresponding period of 2002, reflecting a 7% increase in net general and administrative expenses for the first six months of 2002. The increase in net general and administrative expenses during 2002 is due primarily to a decrease in capitalized general and administrative expenses from $7.4 million during the first half of 2001 to $6.4 million during the second half of 2002. The decrease in capitalized general and administrative expense during the first half of 2002 is a result of a change in the mix of types of expenses being incurred. We incurred more expenses such as consulting and legal fees that are not directly related to our natural gas and oil finding and development activities.

On an Mcfe basis, net general and administrative expenses decreased 50% from $0.24 during the first half of 2001 to $0.12 per Mcfe during the first half of 2002. Excluding the one-time charges taken in the first half of 2001 for the termination of employment contracts totaling $5.2 million, net general and administrative expenses on a per Mcfe basis would have remained unchanged at $0.12 for both the first half of 2001 and the first half of 2002. The flat rate per Mcfe reflects the increase in net general and administrative expenses during 2002 as result of a reduction in capitalized general and administrative expenses during the second half of 2002 combined with an increase in production volume for the current period.

Other Income and Expense - Strategic Review Expenses. During the first six months of 2001, we incurred an additional $119,000 in strategic review expenses. In September 1999, together with KeySpan, our majority stockholder, we had announced our intention to review strategic alternatives for our company and KeySpan's investment in our company. KeySpan was assessing our role within its future strategic plan, and was considering a full range of strategic transactions including the possible sale of all or a portion of our assets. On February 25, 2000, we announced, together with KeySpan, that the review of strategic alternatives for Houston Exploration had been completed.

KeySpan currently holds approximately 67% of our outstanding common stock. As KeySpan has announced in the past, they do not consider the businesses contained in their energy investments segment, including their investment in Houston Exploration, a part of their core asset group. KeySpan has stated in the past that they may sell or otherwise dispose of all or a portion of their non-core assets, but cannot predict when, or if, any such sale or disposition may take place.

Interest Expense, Net of Capitalized Interest. Interest expense, net of capitalized interest, increased 20% from $2.5 million for the first six months of 2001 to $3.0 million for the first six months of 2002. Aggregate interest expense decreased 17% from $8.7 during the first half of 2001 to $7.2 million during the corresponding six month

period of 2002. The decrease in aggregate interest is due to a decrease in interest rates from an average borrowing rate of 7.20% during the first half of 2001 to an average borrowing rate of 5.32% during the first half of 2002 offset in part by an increase in our average borrowings from $210 million during the first six months of 2001 to an average of $256 million for the corresponding period of 2002. Capitalized interest decreased 32% from $6.2 million for the first half of 2001 to $4.2 million for the first half of 2002 and corresponds to the decrease in aggregate interest expense combined with a decrease in exploratory drilling during the first half of 2002 (our capitalized interest is a function of exploratory drilling and unevaluated properties, both of which were at lower levels during the first half of 2002).

Income Tax Provision. The provision for income taxes decreased 66% from $46.3 million for the first six months of 2001 to $15.7 million for the first six months of 2002 due to the 65% decrease in pre-tax income during the first half of 2002 from $129.5 million during the first half of 2001 to $45.9 million during the first half of 2002 as a result of the combination of a decrease in natural gas revenues and increases in both operating expenses and net interest expense.

Operating Income and Net Income. For the six months ended June 30, 2002, operating income decreased 63% from $132.1 million during the first half of 2001 to $48.9 million as a result of a decrease in revenues caused by a 39% decrease in realized natural gas prices offset only in part by the 13% increase in production combined with a 17% increase in operating expenses. Corresponding to the decrease in operating income, net income decreased 64% from $83.2 million for the first half of 2001 to $30.2 million for the first half of 2002 and includes the effects of higher interest expense and lower taxes.

LIQUIDITY AND CAPITAL RESOURCES

We have historically funded our operations, acquisitions, capital expenditures and working capital requirements from cash flows from operations, equity capital from KeySpan as well as public sources, public debt and bank borrowings. We believe cash flows from operations and borrowings under our revolving bank credit facility will be sufficient to fund our planned capital expenditures and operating expenses during 2002.

Cash Flows From Operations. As of June 30, 2002, we had working capital of $23.5 million and $69.6 million of borrowing capacity available under our revolving bank credit facility. Net cash provided by operating activities for the six months ended June 30, 2002 was $108.0 million compared to $218.1 million during the corresponding period of 2001. The decrease in net cash provided by operating activities was due to (i) a decrease in net income caused primarily by lower realized natural gas prices during the first half of 2002, offset in part by an increase in production for the corresponding period combined with (ii) a decrease in current assets and current liabilities which is related to the timing of cash receipts and payments. Funds used in investing activities consisted of $130.7 million for net investments in property and equipment, which compares to $147.0 million spent during the corresponding period of 2001. Our cash position increased during the first half of 2002 as a result of net borrowings under our revolving bank credit facility of $36 million compared to repayments totaling $85 million during the first half of 2001. Cash increased by $1.2 million and $8.1 million, respectively, during the first six months of 2002 and 2001 due to proceeds received from the issuance of common stock from the exercise of stock options. As a result of these activities, cash and cash equivalents increased $14.5 million from $8.6 million at December 31, 2001 to $23.1 million at June 30, 2002.

Capital Expenditures. During the first six months of 2002, we invested $129.6 million in natural gas and oil properties and $1.3 million for other property and equipment, which includes the expansion of our Houston office space together with upgrades to our information technology systems and equipment. Included in our natural gas and oil property additions was $9.2 million for exploration, $57.4 million for development drilling, workovers and construction of platforms and pipelines, $44.5 million for producing property acquisitions and $18.5 million for other leasehold and leasehold acquisition costs which includes seismic, capitalized interest and capitalized general and administrative costs.

Our capital expenditure budget for 2002, set by our Board of Directors, is $250 million. Typically, we do not include property acquisition costs in our capital expenditure budget as the size and timing of capital requirements for property acquisitions are inherently unpredictable. However, we have allocated a portion of our 2002 capital expenditure budget to include the May 30, 2002 acquisition of producing properties in South Texas

from Burlington Resources as we plan to repay the borrowings made under our credit facility for the $44.5 million purchase price from cash flows generated from operations. The capital expenditure budget includes development costs associated with recent acquisitions and discoveries and amounts are contingent upon drilling success. No significant abandonment or dismantlement costs are anticipated in 2002. We will continue to evaluate our capital spending plans throughout the year. Actual levels of capital expenditures may vary significantly due to a variety of factors, including drilling results, natural gas prices, industry conditions and outlook and future acquisitions of properties. We intend to continue to selectively seek acquisition opportunities for proved reserves with substantial exploration and development potential both offshore and onshore, although we may not be able to identify and make acquisitions of proved reserves on terms we consider favorable.

Shelf Registration. On May 20, 1999, we filed a "shelf" registration with the Securities and Exchange Commission to offer and sell in one or more offerings up to a total offering amount of $250 million in securities which could include shares of our common stock, shares of preferred stock or unsecured debt securities or a combination thereof. Depending on market conditions and our capital needs, we may utilize the shelf registration in order to raise capital. We would use the net proceeds received from the sale of any securities for the repayment of debt and/or to fund an acquisition. We may not be able to consummate any offerings under the shelf registration statement on acceptable terms.

Capital Structure

Revolving Bank Credit Facility. We entered into a new revolving bank credit facility dated as of July 15, 2002 with a syndicate of lenders led by Wachovia Bank, National Association, as issuing bank and administrative agent, The Bank of Nova Scotia and Fleet National Bank as co-syndication agents and BNP Paribas as documentation agent. The new credit facility replaces our previous $250 million revolving credit facility maintained with JPMorgan Chase and provides us with an initial commitment of $300 million. The initial commitment can be increased at our request and with prior approval from Wachovia to a maximum of $350 million by adding one or more lenders or by allowing one or more lenders to increase their commitments. The new credit facility is subject to borrowing base limitations, and our initial borrowing base has been set at $300 million and will be redetermined semi-annually with the first redetermination scheduled for October 1, 2002. Up to $25 million of the borrowing base is available for the issuance of letters of credit. The new credit facility matures July 15, 2005, is unsecured and ranks senior to all existing debt.

At June 30, 2002, outstanding borrowings under our previous revolving credit facility were $180 million together with $0.4 million in outstanding letter of credit obligations. Subsequent to June 30, 2002 and prior to entering the new facility on July 15, 2002, we reduced our net borrowings under the previous credit facility by $10 million. Following the July 18, 2002 closing of the new credit facility, funds were drawn on the new facility and used to repay total outstanding borrowings under our previous credit facility of $170 million. Subsequently, we repaid $10 million under the new facility and as of August 12, 2002, total borrowings under the new facility were $160 million and $0.4 million was outstanding under letter of credit obligations.

Senior Subordinated Notes. On March 2, 1998, we issued $100 million of 8?% Senior Subordinated Notes due January 1, 2008. The notes bear interest at a rate of 8?% per annum with interest payable semi-annually on January 1 and July 1. We may redeem the notes at our option, in whole or in part, at any time on or after January 1, 2003 at a price equal to 100% of the principal amount plus accrued and unpaid interest, if any, plus a specified premium which decreases yearly from 4.313% in 2003 to 0% after January 1, 2006 if the notes are redeemed prior to January 1, 2006. Upon the occurrence of a change of control, we will be required to offer to purchase the notes at a purchase price equal to 101% of the aggregate principal amount, plus accrued and unpaid interest, if any. The notes are general unsecured obligations and rank subordinate in right of payment to all existing and future senior debt, including the credit facility, and will rank senior or equal in right of payment to all existing and future subordinated indebtedness.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Natural Gas Hedging

We utilize derivative commodity instruments to hedge future sales prices on a portion of our natural gas production to achieve a more predictable cash flow, as well as to reduce our exposure to adverse price fluctuations of natural gas. Our derivatives are not held for trading purposes. While the use of hedging arrangements limits the downside risk of adverse price movements, it also limits increases in future revenues as a result of favorable price movements. The use of hedging transactions also involves the risk that the counterparties are unable to meet the financial terms of such transactions. Hedging instruments that we use are swaps, collars and options, which we generally place with major investment grade financial institutions that we believe are minimal credit risks and historically, we have not experienced credit losses. Due to the downgrading of the credit rating of Williams Companies, Inc., our outstanding swap and option contracts held with subsidiaries Williams were assigned to Bank of America in July 2002. We believe that the credit risk related to the natural gas futures and swap contracts is no greater than the risk associated with the primary contracts and that the elimination of price risk lowers our overall business risk.

Our hedges are cash flow hedges and qualify for hedge accounting under SFAS 133 and, accordingly, we carry the fair market value of our derivative instruments on the balance sheet as either an asset or liability and defer unrealized gains or losses in Accumulated Other Comprehensive Income. Gains and losses are reclassified from Accumulated Other Comprehensive Income to the income statement as a component of natural gas and oil revenues in the period the hedged production occurs. If any ineffectiveness occurs, amounts are recorded directly to other income or expense.

The following table summarizes the change in the fair value of our derivative instruments for the six month periods from January 1 to June 30, 2002 and 2001, respectively, and does not include the effects of taxes.

CHANGE IN FAIR VALUE OF DERIVATIVES INSTRUMENTS	2002	2001
	(in thousands)	
Fair value of contracts at January 1	$ 53,771	$ (75,06
(Gain) loss on contracts realized	(16,978)	29,23
Fair value of new contracts when entered into during period	--	2,28
(Decrease) increase in fair value of all open contracts	(37,982)	74,45
Fair value of contracts outstanding at June 30, ...	$ (1,189)	$ 30,89

The following table summarizes, on a monthly basis, our hedges for 2002 and 2003. All amounts are in thousands, except for prices. For the remaining months of 2002, we have hedged approximately 64% of our estimated production or a total of 190,000 MMBtu/day at an effective floor of $3.389 and an effective ceiling of $4.801. For the year 2003, we have 110,000 MMBtu/day hedged at an effective floor of $3.352 and an effective ceiling of $4.324.

	FIXED PRICE SWAPS		COLLARS		
PERIOD	VOLUME (MMBTU)	NYMEX CONTRACT PRICE	VOLUME (MMBTU)	NYMEX CONTRACT PRICE AVG FLOOR	NYMEX CONTRACT PRICE AVG CEILING

July 2002	930	$ 3.010	4,960	$ 3.561	$ 5.137
August 2002	930	3.010	4,960	3.561	5.137
September 2002	900	3.010	4,800	3.561	5.137
October 2002	930	3.010	4,960	3.561	5.137
November 2002	900	3.010	4,800	3.561	5.137
December 2002	930	3.010	4,960	3.561	5.137
January 2003	1,240	3.194	2,170	3.443	4.970
February 2003	1,120	3.194	1,960	3.443	4.970
March 2003	1,240	3.194	2,170	3.443	4.970
April 2003	1,200	3.194	2,100	3.443	4.970
May 2003	1,240	3.194	2,170	3.443	4.970
June 2003	1,200	3.194	2,100	3.443	4.970
July 2003	1,240	3.194	2,170	3.443	4.970
August 2003	1,240	3.194	2,170	3.443	4.970
September 2003	1,200	3.194	2,100	3.443	4.970
October 2003	1,240	3.194	2,170	3.443	4.970
November 2003	1,200	3.194	2,100	3.443	4.970
December 2003	1,240	$ 3.194	2,170	$ 3.443	$ 4.970

These hedging transactions are settled based upon the New York Mercantile Exchange or NYMEX price on the final trading day of the month. In order to determine fair market value of our derivative instruments, we obtain mark-to-market quotes from external counterparties.

With respect to any particular swap transaction, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap price for the transaction, and we are required to make payment to the counterparty if the settlement price for any settlement period is greater than the swap price for the transaction. For any particular collar transaction, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price for the transaction, and we are required to make payment to the counterparty if the settlement price for any settlement period is above the ceiling price for the transaction. We are not required to make or receive any payment in connection with a collar transaction if the settlement price is between the floor and the ceiling. For option contracts, we have the option, but not the obligation, to buy contracts at the strike price up to the day before the last trading day for that NYMEX contract.

PART II. OTHER INFORMATION

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

On May 12, 2002, the company held its annual meeting of stockholders. All matters brought for a vote before the shareholders as listed in the Company's proxy statement were approved as follows:

1. The election of the following nine Directors of the Company to serve until the Company's next annual meeting:

DIRECTOR	VOTES FOR	VOTES WITHHELD

Robert B. Catell	28,131,744	1,192,968
William G. Hargett	28,245,888	1,078,824
Gordon F. Ahalt	29,247,478	77,234
David G. Elkins	29,249,478	75,234
Robert J. Fani	28,244,512	1,090,200
Russell D. Gordy	28,246,978	77,734
Gerald Luterman	28,247,352	1,077,360
H. Neil Nichols	28,247,412	1,077,300
James Q. Riordan	29,248,673	76,039
Donald C. Vaughn	29,249,078	75,634

2. The appointment of Deloitte & Touche LLP as the Company's independent public accountants for the fiscal year ending December 31, 2002.

VOTES FOR	VOTES AGAINST	ABSTAINED
29,222,165	99,817	2,730

3. Approval of the 2002 Incentive Stock Plan.

VOTES FOR	VOTES AGAINST	ABSTAINED
27,404,728	1,903,903	16,081

ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K:

(a) Exhibits:

EXHIBITS		DESCRIPTION
10.1(1)	--	Revolving Credit Facility between The Houston Exploration Company and Wachovia Bank, National Association, as issuing bank and administrative agent, Bank of Nova Scotia and Fleet National Bank as co-syndication agents and BNP Paribas as documentation agent dated July 15, 2002.
10.2(1)(2)	--	First Amendment to Employment Agreement between The Houston Exploration Company and William G. Hargett dated May 17, 2002.

28

99.1(1)	--	Certification of William G. Hargett, Chief Executive Officer, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.2(1)	--	Certification of James F. Westmoreland, Chief Accounting Officer, as required pursuant to Section 906 of the Sarbanes -

Oxley Act of 2002.

----
(1) Filed herewith.
(2) Management contract or compensation plan.

(b) Reports on Form 8-K:

Current Report on Form 8-K filed on March 25, 2002 to provide new information regarding hedges for the years ended December 31, 2002 and 2003 in Item 5. - Other Events.

Current Report on Form 8-K filed April 5, 2002 to provide information regarding change of certifying accountant in Item 4. - Changes in Registrant's Certifying Accountant.

29

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, hereunto duly authorized.

THE HOUSTON EXPLORATION COMPANY

By: /s/ WILLIAM G. HARGETT

Date: August 12, 2002

William G. Hargett
President and Chief Executive Officer

By: /s/ JAMES F. WESTMORELAND

Date: August 12, 2002

James F. Westmoreland
Vice President, Chief Accounting Officer
and Secretary

30

EXHIBIT INDEX

EXHIBIT NUMBER		DESCRIPTION
10.1(1)	--	Revolving Credit Facility between The Houston Exploration Company and Wachovia Bank, National Association, as issuing bank and administrative agent, Bank of Nova Scotia and Fleet

		National Bank as co-syndication agents and BNP Paribas as documentation agent dated July 15, 2002.
10.2(1)(2)	--	First Amendment to Employment Agreement between The Houston Exploration Company and William G. Hargett dated May 17, 2002.
99.1(1)	--	Certification of William G. Hargett, Chief Executive Officer, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.2(1)	--	Certification of James F. Westmoreland, Chief Accounting Officer, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

----

(1) Filed herewith.

(2) Management contract or compensation plan.