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

FORM 10-K/A

(Amendment No. 1)

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

For the Fiscal Year Ended December 31, 2004

Commission File Number 0-9120

THE EXPLORATION COMPANY OF DELAWARE, INC.

(Exact name of Registrant as specified in its charter)

Delaware	**84-0793089**
(State or other jurisdiction of incorporation or organization)	(I.RS. Employer Identification No.)

500 North Loop 1604 East, Suite 250, San Antonio, Texas 78232
(Address of principal executive offices)

Registrant's telephone number, including area code: **(210) 496-5300**

Securities registered pursuant to Section 12(b) of the Act: **None**

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

Common Stock, par value $0.01 per share

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

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the act). Yes ☒

The aggregate market value of the voting stock (which consists solely of shares of Common Stock) held by non-affiliates of the registrant was $88.7 million based upon the closing price of $3.79 per share of such stock as reported by the NASDAQ Small-Cap Market under the symbol TXCO on June 30, 2004.

The number of shares outstanding of the Registrant's Common Stock as of March 4, 2005, was 28,165,563 of which 23,612,819 shares were held by non-affiliates.

Documents Incorporated by Reference: Portions of the Company's Proxy Statement pertaining to the 2005 Annual Shareholders' Meeting, to be held on May 13, 2005, are incorporated herein by reference into Part III.

For more information, go to www.txco.com.

Explanatory Note

This Amendment to the Annual Report on Form 10-K is the result of a staff review by the Division of Corporation Finance, which requested clarification of several items and the removal of subtotals on certain tables. It is being filed for the purpose of amending the following items of the Annual Report:

(i) Item 2 (Properties)
To amend the description of the calculation of PV-10 Value

(ii) Item 6 (Selected Financial Data)
To add two additional data items

(iii) Item 7 (Management's Discussion and Analysis of Financial Condition and Results of Operations)
Overview section:
(a) To provide a description of the calculation of reserve replacement ratio and a cross reference to the discussion in the "Reliance on Estimates of Proved Reserves" section regarding the uncertainties surrounding reserve estimates
(b) To add a paragraph on "Reserve Replacement"
Critical Accounting Policies and Estimates section:
(c) To add a paragraph on the handling of the sale of a partial interest in an unproved property
Sarbanes Oxley Section 404 Implementation section:
(d) To modify the final sentence in the first paragraph of the Sarbanes Oxley 404 discussion.

(iv) Item 8 (Financial Statements and Supplementary Data):
(a) To replace the "Report of Independent Registered Public Accounting Firm" due to the reference to auditing in accordance with U.S. generally accepted auditing standards, rather than the newly required verbiage of "in accordance with the standards of the Public Company Accounting Oversight Board (United States)"
(b) To remove the subtotal labeled "Net cash provided by operating activities, before changes in operating assets and liabilities" from the "Consolidated Statements of Cash Flows"
(c) To add additional disclosure regarding 3-D seismic to Note A under "Oil and Gas Properties"
(d) To remove a subtotal line labeled "Future net cash inflows before income tax" from the "Standardized measure" table in Note L

(v) Item 9A (Controls and Procedures):
(a) To remove the word "significant" from the third and fourth sentences

Note: There are no other changes to the original Form 10-K filing other than those outlined in this document. This Amendment does not affect the financial results reflected in the financial statements as originally filed. This Form 10-K/A does not reflect events occurring after the filing of the original Form 10-K, or modify or update the disclosures therein in any way other than as required to reflect the amendments summarized above.

INDEX AND
CROSS REFERENCE SHEET

PART I

ITEM 1. BUSINESS

FORWARD-LOOKING STATEMENTS

Statements in this Form 10-K which are not historical, including statements regarding TXCO's or management's intentions, hopes, beliefs, expectations, representations, projections, estimations, plans or predictions of the future, are forwarding-looking statements and are made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. Such statements include those relating to expected drilling plans, including the timing, category, number, depth, cost and/or success of wells to be drilled, expected geological formations or the availability of specific services or technologies. It is important to note that actual results may differ materially from the results predicted in any such forward-looking statements. Investors are cautioned that all forward-looking statements involve risks and uncertainty, including without limitation, the costs of exploring and developing new oil and natural gas reserves, the price for which such reserves can be sold, environmental concerns affecting the drilling of oil and natural gas wells, as well as general market conditions, competition and pricing. Please refer to TXCO's Securities and Exchange Commission filings for additional information. This and all TXCO's previously filed documents are on file at the Securities and Exchange Commission and can be viewed on TXCO's website at www.txco.com. Copies are available from the Company without charge.

GENERAL DEVELOPMENT OF BUSINESS

The Exploration Company (the "Company" or "TXCO") was incorporated in the State of Colorado on May 16, 1979, for the purpose of engaging in oil and gas exploration, development and production and became publicly held through an offering of its common stock in November 1979. In May 1999, the Company changed its state of incorporation from Colorado to Delaware, becoming The Exploration Company of Delaware, Inc. The Company continues doing business as The Exploration Company and its trading symbol on the Nasdaq Stock Market[SM] remains TXCO. Effective in January 2000, the Company changed its annual reporting period from a fiscal year ending August 31 to a calendar year ending December 31.

The Company has a consistent record of long-term growth in its proved oil and gas reserves, leasehold acreage position, production and cash flow through its established exploration and development programs. Its business strategy is to build shareholder value by acquiring undeveloped mineral interests and internally developing a multi-year drilling inventory through the use of advanced technologies, such as 3-D seismic and horizontal drilling. The Company strives to discover, develop and/or acquire more oil and gas reserves than it produces each year from these internally developed prospects. As opportunities arise, the Company may selectively participate with industry partners in prospects generated by TXCO as well as by other parties. The Company also attempts to maximize the value of its technical expertise by contributing its geological, geophysical and operational core area competencies through joint ventures or other forms of strategic alliances with well capitalized industry partners in exchange for carried interests in seismic acquisitions, leasehold purchases and/or wells to be drilled. From time to time, the Company offers portions of its developed and undeveloped mineral interests for sale. The Company finances its activities through internally generated operating cash flows, as well as debt financing and equity offerings, or sale of interests in properties when favorable terms or opportunities are available.

The continued availability of new equity and debt capital in 2004, combined with the re-investment of TXCO's growing positive cash flow provided from operations, reaffirms Management's ongoing strategy for improved shareholder value by maintaining a focus on its core business of oil and gas exploration and production. This strategy has allowed the Company to attract recognized industry partners, expand its core area leasehold acreage, increase its 3-D seismic database and interpretative skill set. This strategy, coupled with the Company's drill bit success, has allowed TXCO to grow its reserve base while maintaining a conservative debt profile. In 2004, the Company doubled its available bank credit facility with a $50 million reserve-based facility. The Company has remained focused on the Maverick Basin and has successfully established a multi-year portfolio of drilling targets within its core area. To support its growing asset base in the Maverick Basin, the Company acquired a 69-mile natural gas gathering system in 2002. At year-end 2004, the Company's natural gas gathering system has grown to more than 90 miles of pipeline. The gathering system assures TXCO's access to North American markets, enables TXCO to realize higher prices for its natural gas and better share in proceeds from extraction of natural gas liquids.

TXCO continued its ongoing trend of strong annual reserve growth in 2004 as it recorded net proved reserve additions of 9.5 billion cubic feet equivalent ("Bcfe"). Combined with annual production of 4.9 Bcfe, TXCO's gross reserve additions for the year were 14.4 Bcfe. Estimated year-end proved oil and gas reserves were a record 37.9 Bcfe, a third above its 28.4 at year-end 2003. The Company achieved a 295 percent all-source reserve replacement rate in 2004.

Positive cash flow provided from operations reached $16.4 million, an 8.5% increase over the prior year. See the Development table in the Overview section of the Management's Discussion and Analysis for more information.

Over the years, TXCO has significantly expanded and developed its natural gas and oil production base in the Maverick Basin. This overall growth is primarily attributable to the Company's focused exploration activities fed by the expansive array of drilling opportunities across its lease block. This growth has been accelerated through strategic acquisition of new non-developed leasehold acreage as well as producing properties adjacent to TXCO's existing core acreage with significant undeveloped potential.

TXCO's established operating strategy includes the pursuit of multiple growth opportunities based on diversification in exploration targets within its core area of operations. By aggressively expanding its surrounding lease holdings where geology indicates the likely continuation of known or prospective oil and gas producing formations, TXCO is well positioned to pursue new oil and gas reserves and expand its production base. The Maverick Basin offers this diversity in its multiple hydrocarbon bearing horizons. During 2004, the Company expanded its Maverick Basin lease block to 554,000 contiguous acres. In addition, TXCO successfully completed a total of 52 wells in various horizons, including 27 new oil wells in the San Miguel, Georgetown, Glen Rose and Red River formations, while 25 new gas wells were completed in the Glen Rose, Georgetown and Pearsall formations. See the last paragraph of this section for developments subsequent to year-end 2004.

During 2004, the Company expanded its oil and gas reserves and production base by pursuing exploration in eight distinct Maverick Basin plays, ranging from the shallow Olmos to the deep Jurassic. New seismic processing techniques were applied during the last 18 months accelerating development of Georgetown oil and gas production on the southern and northern portions of the lease block. The advanced seismic techniques also appear to significantly improve the productive potential of the complex Glen Rose porosity play. Exploration and development targets for 2005, in descending depth order, include: expanding waterflood oil production from the San Miguel interval; expanding oil and gas production from Georgetown horizontal wells; continued horizontal and vertical drilling for Glen Rose shoal and reef gas production; and additional Comanche lease horizontal wells targeting Glen Rose porosity oil production. As 2004 results again confirmed, each of these high impact exploration and development targets has the potential to establish meaningful additions to TXCO's oil and gas production and proved reserves, along with significant numbers of new, proved undeveloped, lower risk drilling locations.

Should its exploration and development plans progress as intended, the Company expects continued growth of its oil and gas reserves and production levels in 2005. TXCO established a range of $26 million to $33 million for its 2005 capital expenditure budget ("CAPEX"), with 94% of the minimum amount, or $24.9 million, earmarked for drilling 59 new wells and four re-entries targeting three primary horizons. The remaining $1.5 million will go toward seismic acquisition, lease extensions and water injection well conversions. The budget may expand or contract based on drilling results, operational developments, unanticipated transaction opportunities, market conditions, commodity price fluctuations and working capital availability. Based on its continued drilling success, the Company expects to be profitable in 2005, and further expects it will have sufficient working capital available from traditional sources, including cash flow from operations and borrowings from its growing reserve-based bank credit facility, as well as industry sources and public equity markets, as needed. Although there is no assurance the Company will be successful in maintaining its ongoing drilling success at sufficient levels to fund its capital needs during 2005, Management retains its ability to increase or decrease its capital expenditure program consistent with its available liquidity in order to continue to meet its ongoing operating and debt service obligations on a timely basis.

In December 2004, TXCO retained Raymond James & Associates to assist in actively pursuing strategic alternatives designed to enhance shareholder value, including a merger or sale of the Company. No formal decisions have been made and no agreements have been reached at this time. There can be no assurances that any particular alternative will be pursued or that any transaction will occur, or on what terms.

In February 2005, TXCO acquired a 50% interest in more than 174,000 gross acres in Maverick, Dimmit, and Zavala counties. This additional acreage lies mostly contiguous, to the south and east of the Company's existing lease block and is prospective for many of the Company's active plays, including in descending depth order, the Escondido, Olmos Coals (CBM), San Miguel, Austin Chalk, Eagleford, Buda, Georgetown, Glen Rose, Pearsall, Sligo and Jurassic targets. The Company exchanged a 50% interest in shallow zones (to the base of the San Miguel formation) in certain of its Comanche and Chittim leases, and all depths in certain other Chittim leases, for the interest. Subsequent to this transaction TXCO holds a position in 727,000 gross acres (490,000 net acres), with an average working interest of 68%.

PRINCIPAL AREAS OF ACTIVITY

Oil and Gas Operations

Again in 2004, the Company actively developed its core mineral interests in the Maverick Basin in South Texas. These activities included the drilling or re-entry of 66 wells in South Texas during 2004, as compared to 79 in 2003. The Maverick Basin drilling activity reflects the Company's continued ability to generate working capital from healthy internal operating margins, and industry sources, along with proceeds from private equity placements, allowing for expansion of its Texas-based lease acreage holdings and natural gas exploration and production activities. Higher natural gas production levels and strong commodity prices, offset partially by a decrease in Maverick Basin oil production during 2004, resulted in increased net cash provided by operating activities totaling $16.4 million in 2004 compared to $15.2 million in 2003.

The Company's strategy remains focused on its core oil and natural gas producing properties and higher margin exploration activities in the Maverick Basin. The Company continues to evaluate economic alternatives related to its remaining properties in the Williston Basin, primarily in North Dakota, and participated in the drilling of one well and two re-entries in this area during 2004, up from one re-entry in 2003. TXCO has continued efforts to either locate suitable joint venture partners, farmout, or sell its interest in the Williston Basin.

Maverick Basin

At year-end 2004, the Company had an interest in approximately 554,000 acres in the Maverick Basin, with an average working interest of over 85%. A large portion of this contiguous lease block is situated on the Chittim Anticline, a large regional geologic structure, within which hydrocarbons have been found in at least 14 separate horizons. One of these zones is the Lower Glen Rose or Rodessa interval. It is a carbonate formation that has produced billions of cubic feet of natural gas from patch reefs within the zone. Past development in the area was halted due to the inability of previous operators to identify or accurately predict the location of these porosity-bearing reefs. In the early 1990's, utilizing new technological advances, TXCO applied an innovative processing method to the 2-D seismic available in the area and confirmed a method of locating these porosity intervals. Encouraged by these early findings, the Company initiated one of the first 3-D seismic acquisition programs in the Maverick Basin. Utilization of 3-D seismic survey data is an integral part of TXCO's interpretative methodology for the identification and evaluation of drilling prospects in most all of its active plays. The Company first acquired a leasehold interest on 50,000 acres in the Maverick Basin in 1989. TXCO's interest in the Basin has grown steadily over the years, as indicated by the following table:

Fiscal Year End	Gross Acreage Under Lease or Option	
1997	56,400	
1998	65,200	
1999	115,000	
2000	365,000	
2001	372,000	
2002	409,000	
2003	480,000	
2004	554,000	*

* By mid-February 2005 TXCO's gross acreage under lease or option was approximately 727,000 acres.

During 2004, TXCO completed its latest 3-D seismic survey covering more than 22 square miles of its Pena Creek leases. The Company also acquired 3-D seismic data covering an additional 22 square miles on its Hollimon lease. Initial interpretations identified numerous drillable locations in several distinct intervals, including the Georgetown and Glen Rose formations. A portion of these locations has been included in the 2005 capital expenditure budget.

At year-end 2004 the Company had accumulated over 764 square miles of 3-D seismic data covering more than 75% of its 865-square-mile (equivalent to 554,000 acres) Maverick Basin lease block. This represents an increase of 55 square miles of 3-D data over year-end 2003, expanding the seismic coverage over a significant portion of the Pena Creek and Hollimon leases. In February 2005, TXCO finalized a lease exchange program under which it acquired an additional 140 square miles of 3-D seismic data on the newly acquired leases, bringing the Company's total 3-D seismic database to 904 square miles over mostly contiguous leases.

TXCO geologists and geophysicists have identified and mapped numerous geological formations at various depths on most of its lease block, providing a growing, multi-year inventory of alternative drilling prospects for the ongoing evaluation of horizons known to be productive for oil and/or gas within and around its leases in the Maverick Basin. The active plays under ongoing evaluation by the Company's engineers are described under the "Maverick Basin Plays" heading later in this section.

In February 2005, as footnoted in the previous table, TXCO acquired a 50% interest in more than 174,000 gross acres in Maverick, Dimmit, and Zavala counties. This additional acreage lies mostly contiguous, to the south and east of the Company's existing lease block and is prospective for many of the Company's active plays, including in descending depth order, the Escondido, Olmos Coals (CBM), San Miguel, Georgetown, Glen Rose, Pearsall, Sligo and Jurassic targets. The Company exchanged a 50% interest in shallow zones (to the base of the San Miguel formation) in certain of its Comanche and Chittim leases, and all depths in certain other Chittim leases, for the interest. Subsequent to this transaction TXCO holds a position in approximately 727,000 gross acres (490,000 net acres), with an average working interest of 68%.

2004 Drilling Activity Summary

TXCO participated in drilling a total of 60 gross wells and nine re-entries during 2004. Of the 60 total wells, 44 were completed and 16 remained in progress at year-end, with no dry holes for the year. Completed Maverick Basin wells include 22 producing oil and 21 producing gas, while the one well drilled in South Dakota is producing oil. One oil and one gas well in progress at December 31, 2003 were completed in early 2004, both in the Georgetown formation. A total of 54 wells remained in progress at year-end, including wells remaining from prior years (see the "In Progress Recap" for further information). Six of the nine re-entry attempts resulted in producing well completions, three oil and three natural gas, in five different formations. The three re-entries that are producing oil include two in the Williston Basin.

TXCO's approximate working interest ownership in some of its Maverick Basin projects, at February 28, 2005 are detailed below by formation in descending depth order:

		Working Interest Range
1	Escondido - Gas	50% to 100%
2	Olmos - CBM Gas	50% to 100%
3	San Miguel - Oil Waterflood	50% to 100%
4	Georgetown - Gas and Oil	2% to 100%
5	Glen Rose - Oil Porosity Zone	50% to 75%
6	Glen Rose - Gas Shoals and Reefs	48% to 100%
7	Jurassic - Gas	2% to 100%

At year-end 2004, TXCO's net field production exit rate was 11.7 million cubic feet per day ("MMcfd") (gross 29.3 MMcfd) from 91 net gas wells plus 1,285 barrels of oil per day ("BOPD") (gross 5,648 BOPD) from 167 net oil wells. These net field production rates were up from year-end 2003, when gas rates were 8.9 MMcfd (gross 23.8 MMcfd) from 75 net gas wells, while the oil rate was 1,200 BOPD (gross 5,900 BOPD) from 179 net oil wells. The expanding geophysical database, historical drilling results and the growing number of prospective formations targeted by the Company and its partners reaffirmed the Company's longstanding belief it has very significant exploration and development possibilities on its growing Maverick Basin lease block.

Maverick Basin Plays

Georgetown

The Company spudded 25 new Georgetown wells and re-entered one well, in addition to three Georgetown completions originally targeting Glen Rose reefs. TXCO drilled or re-entered 18 Georgetown wells in 2003. The gross field production exit rate from the Georgetown formation stood at 17.2 MMcfe per day ("MMcfed") compared with 9.1 MMcfed at December 31, 2003. This increase relates to new wells placed on production during 2004 in the Comanche-Halsell lease (50% WI) and on the Burr lease (100% WI). The current 2005 CAPEX budget includes $16.9 million for 33 new wells and one re-entry, as well as completion of two wells in progress at year-end targeting this formation.

TXCO and its partners drilled the last four wells in 2003 using a new seismic technique, called coherency processing, that more accurately predicts the location of formation faults and fractures. By using coherency processing, the Company has initially identified more than 300 potential Georgetown well locations on its 130,000-acre Comanche prospect alone. It expects to establish a significant additional number of locations on its remaining lease block. The technique does not differentiate the type of reservoir fluids to be recovered from the fracture network. TXCO identified an oil-producing province in the northern portion of its lease acreage by the completion of five oil wells on the Briscoe-Saner lease during 2003. Historically, the old Wipff-Fitzpatrick field produced oil from the fractured Georgetown interval across the Burr lease acreage acquired by TXCO in January 2003. Over 20 miles away in the southern portion of TXCO's lease block, recent drilling across the Comanche/Pena Creek leases has resulted in rich gas production with minimal amounts of condensate. Since the Georgetown is a fractured reservoir, it is difficult to predict the type and quantity of ultimate reserves for each well as such reservoirs typically have hyperbolic decline curves, with high initial production rates that rapidly fall to lower, sustained rates. While only the last four of the 18 Georgetown wells TXCO drilled or re-entered in 2003 utilized the new seismic technique, coherency processing was employed on all of the 2004 wells drilled. Georgetown proved reserve estimates have increased to 7.5 Bcfe over 5.7 Bcfe at year-end 2003. TXCO's internal reservoir engineers believe that proved reserves will further increase as sufficient additional production history is established.

Through early March 2005, the Company has spudded six horizontal Georgetown wells and participated in the re-entry of one Georgetown well. At March 4, 2005, four of these new wells, and the re-entry, are awaiting completion while the remaining two wells continue drilling.

Glen Rose Oil

During 2002 and 2003, the Company significantly advanced its joint venture with Saxet Energy, Ltd. ("Saxet"), a privately held Houston exploration company, and Tom Brown, Inc. (Nasdaq: TMBR), a large Denver-based independent, covering TXCO's 130,000-acre Comanche prospect. In 2001, the Company sold a 50% working interest (Saxet 20% and Tom Brown 30%) in its rights below the base of the San Miguel formation, and the joint venture partners completed the acquisition of a proprietary, 100-square mile, 3-D seismic survey covering the western half of the Comanche prospect, including Saxet's Cinco Ranch lease on the western flank of the Comanche acreage. Based on early interpretation of the seismic survey, a well targeting the Glen Rose formation was spudded in June 2001 on the Cinco Ranch lease. Unfortunately the reef was water bearing. By year-end 2002, the partners completed the acquisition and processing of the entire 3-D survey, identifying additional Glen Rose reefs. A second well was planned targeting a prospect on TXCO's Comanche lease, which contained evidence of multiple Glen Rose prospects stacked over a previously unidentified structure. This well was the discovery well for the Comanche Halsell (6500) field and tested at rates over 2,000 BOPD. Initial drilling found no productive reefs, but discovered a highly fractured porosity interval.

By year-end 2003, 27 Saxet-operated Comanche wells had been drilled, with the 17 wells on production at that time spread over a 20 square-mile area. 40-degree gravity oil is consistent throughout the entire area, which contains no gas. The partners' engineering staffs completed extensive reviews of the porosity intervals and its oil and water production profiles. Additionally, seismic has been integrated with the Comanche Halsell field production profile. Management believes that significant additional proved reserves will be established. Until such time that water production issues are fully resolved for affected wells and adequate production profiles are established for newly completed wells, the Company's ongoing engineering estimates will be unable to reflect the full reserve potential attributable to the Comanche lease oil discovery.

In January 2004, Saxet announced its intention to liquidate its holdings in its Maverick Basin leaseholds and producing properties. TXCO was not successful in its efforts to purchase any portion of Saxet's interest in the Comanche/Pena Creek prospect. In late March, Saxet became CMR Energy L. P. through a corporate restructuring in which new management was installed. This restructuring delayed the drilling program for this prospect through the first half of 2004.

The gross field production exit rate from the Comanche Halsell (6500) Field, at year-end 2004, stood at 975 BOPD and 8,104 BWPD from 14 producing wells. This compares to a 2003 exit rate of 1,317 BOPD and 9,195 BWPD from 16 producing wells. Only two new horizontal wells were spudded during 2004 and two additional wells were re-entered. Both new wells are producing oil while the re-entries remained in progress at year-end. By comparison, 13 wells were drilled during 2003, with six drilled horizontally and seven drilled vertically to delineate the areal extent of the porosity's oil-bearing rock. Saxet drilled five of the 2003 horizontal wells 50 to 150 feet above the porosity interval, only intersecting and draining those faults that extended above the zone. These wells did not respond as expected, contributing to the overall decline in field production late in that year. TXCO engineers have believed for some time that drilling horizontal laterals staying within the porosity zone could result in enhanced oil production from this complex fractured reservoir. The combined number of wells drilled since the oil play's discovery in February 2002 stands at 29. The wells in 2004 were drilled in the porosity zone and are producing oil. Cumulative gross oil production has surpassed 1.8 million barrels of oil to date. The project remains profitable and economics should improve as the partners better define the expansive play and perfect drilling techniques used to maximize the recovery of oil in the formation. Net proved reserves at December 31, 2004 for the Glen Rose oil porosity zone are estimated at 744,942 BO, equivalent to 4.5 Bcfe, up from 243,240 BO (1.5 Bcfe) for the prior year.

Drilling in the Glen Rose porosity zone resumed on the Comanche lease with the end of the annual hunting season drilling moratorium in January 2005. In mid-February 2005, TXCO's operating partner re-entered a Comanche well and performed a sidetrack to test the Glen Rose formation, which is currently awaiting completion. The 2005 CAPEX budget includes $2.1 million for three new wells and three re-entries in this oil play.

Glen Rose Gas

In late 2001, TXCO announced the discovery of a horizontal Glen Rose shoal gas play on a portion of its Chittim lease. Company geologists analyzed a large carbonate shoal (or carbonate "sand" bar) located within the Glen Rose interval. The target area provided good well control from nearby vertical producing wells that had logged or otherwise penetrated the structure while attempting completions in other oil or gas-bearing horizons. The Company drilled a horizontal well to see if recovery could be improved. The Chittim 1-141, the first well completed in this program, went on production in 2001 at a rate of 2.0 MMcfd, has cumulative production through February 28, 2005 of 1,009 MMcf, and is still producing about 200 Mcfd. As provided under its farm-in agreement with AROC-Texas Inc., covering this portion of the Chittim lease, the Company drills and completes these horizontal Glen Rose shoal wells and AROC operates them.

TXCO continued its horizontal Glen Rose shoal drilling program in 2004, drilling 10 successful gas wells in a row (38% to 62.5% WI), adding to its string of 19 successful horizontal gas well completions through 2003. TXCO spudded seven new Glen Rose reef wells during 2004, with two producing gas at year end, and two awaiting completion into another zone, while the remaining three were recompleted into the Georgetown formation and are producing oil. At December 31, the Glen Rose gas net field production exit rate was 5.5 MMcfd, compared with 5.1 MMcfd at year-end 2003. The field has produced 8.1 Bcf since horizontal drilling techniques were applied. At December 31, 2004, net proved gas reserves for Glen Rose were estimated at 11.2 Bcfe, down from 12.6 for the prior year.

Plans for 2005 include drilling three low-risk Glen Rose shoal wells estimated to cost $1.3 million.

San Miguel Waterflood

Pena Creek: In 2002, the Company acquired the Pena Creek oil field in Dimmit County, Texas, which included 94 producing oil wells, 94 injection wells and 28 shut-in wells. During 2002, TXCO completed a 3-D seismic survey covering the Pena Creek field and surrounding acreage. The Company completed an extensive geological, engineering and 3-D seismic review, including the review of historic well data acquired with the property. These evaluations enabled the Company to identify bypassed infill San Miguel oil reserves not presently included in the Company's reserve base, establishing more than 80 potential infill locations to date, with further potential to establish additional infill locations as warranted by ongoing drilling results. Additional oil recovery is expected from planned revamping of injection well configuration. During 2004, the Company completed a 3-D seismic survey on an additional 22 square miles in the Pena Creek area.

During 2004, the Company drilled 10 infill wells targeting bypassed reserves, successfully completing all 10 of those wells, as compared to successfully completing 21 of 23 wells during 2003. At year-end 2004, the Pena Creek San Miguel formation net field production exit rate was approximately 303 barrels of oil per day ("BOPD"), and 910 BWPD, down from 400 BOPD and 1,213 BWPD at December 31, 2003. Net proved reserves at year-end for this field were estimated at 2.2 million barrels, equivalent to 13 Bcfe, up from 1.5 million barrels (9 Bcfe) at year-end 2003. The 10,000-acre Pena Creek prospect is contiguous to the Company's Comanche lease and is also prospective for oil and natural gas production from the underlying Georgetown and Pryor formations. The 2005 CAPEX budget includes $2.8 million for 10 new wells in the San Miguel waterflood.

Jurassic

The Company initiated a joint venture with Blue Star Oil and Gas, Ltd. ("Blue Star"), a Dallas-based privately held exploration company, to explore the potential of the Jurassic formation under its growing lease block in fiscal 1999. The joint venture expanded the 3-D seismic database, and analyzed the results of the more than 426-square-mile area of the Maverick Basin targeted by the joint venture. Blue Star applied enhanced 3-D seismic processing and provided TXCO with a digitized data set covering the entire target area.

On March 27, 2003, Blue Star spudded the Taylor 1-132 on TXCO's Paloma lease. The well, targeting natural gas, reached total depth at 22,400 feet in late December 2003. The well found multiple sands in the Jurassic and provided valuable geologic information about the formation, which should prove helpful in future drilling. Blue Star tested numerous horizons below 18,000 feet and one above 18,000 feet. The zone at 16,800 feet flowed non-commercial quantities of 1,200 Btu/cf natural gas.

Prior to becoming operator, TXCO and its minority partners had no cost in the well as they benefited from a 25% carried interest under the original terms of the agreement with Blue Star. In February 2004, TXCO assumed operation of the well and perforated and tested two upper Jurassic intervals at 14,942 to 15,140 feet and 15,292 to 15,400 feet. With assumption of operations, TXCO initially owned 62.5% of the well and would bear its proportionate cost of testing and completing the remaining untested portions of the well. TXCO's long-standing minority partners retained the remaining 37.5% working interest. Blue Star did not retain any interest in the well. In March 2004, the Company signed an agreement with Kayne Anderson Energy Fund II L.P. ("KAEF") Los Angeles, whereby KAEF agreed to pay 48.75% of the Taylor well's completion costs in exchange for a 34.125% net profit interest in the well, reducing TXCO's effective working interest in the well to 40.625%. The Company tested the Sligo formation and determined that production could not be enhanced by stimulation. TXCO proceeded to test the Pearsall formation and placed the well on production. At year-end 2004, the net exit rate for the well was 114 Mcfd and 1 BOPD.

By drilling the Taylor wildcat, Blue Star earned a 25% working interest in all depths below the Sligo formation under the 50,000 acres included in TXCO's Paloma and Kincaid leases, except for the 640-acre drilling unit surrounding the Taylor well. Blue Star has confirmed its ongoing intention to drill a second Jurassic well in the basin on Blue Star's own lease, utilizing information obtained from the Taylor well. Overall, TXCO holds rights to the Jurassic on more than 400,000 acres of its Maverick Basin interests with numerous potential locations identified by the Company's 3-D seismic studies. TXCO's 2005 drilling budget does not include expenditures for a second Jurassic well.

Olmos/Escondido

TXCO drilled one shallow Olmos well (100% WI) in 2004 on its Comanche lease. The well was awaiting completion at year-end. No funds have been included in the initial 2005 CAPEX budget for this program.

The low cost associated with drilling at these shallow depths provides attractive development opportunities. Economic development of the shallow Escondido/Olmos sands, with depths ranging from approximately 700 to 1,900 feet, will accelerate as pipeline infrastructure grows along with the development of additional Georgetown gas production in the immediate area.

Coalbed Methane

TXCO remains firmly entrenched at the forefront of Texas-based exploration for CBM gas production. The United States Geological Survey ("USGS") credited TXCO with the establishment of the first CBM field in Texas in April 2001. The Texas Railroad Commission assigned the name "Sacatosa (CBM Olmos) Field" to the extensive coal deposits which extend across approximately 250,000 acres of TXCO's lease block under its Comanche and Chittim leases. Eager to encourage the continuing development of this potential new source of CBM gas, the USGS formed a cooperative research effort with TXCO to determine the gas in place, rank, quality, extent and thickness of the Olmos coals in order to fully assess the resource potential of the new CBM field. In 2001, the USGS drilled two CBM wells on the Comanche lease with TXCO, collecting extensive amounts of samples and data for further laboratory testing and evaluation. Extensive desorption and adsorption tests on these wells, as well as 10 additional core tests, confirmed the coals were gas-saturated. Published coal quality data confirmed the Olmos coals are classified as having the favorable ranking of high-volatile C bituminous coal, which is preferable for potential CBM production. Additional measurements indicated samples of Olmos coal from the Sacatosa (CBM Olmos) Field from varying depths contained quantities of CBM gas ranging to as much as 350 standard cubic feet per ton of coal. Further study confirmed the thickness, depth and gas content of the Olmos coals were similar to coals in other established and commercially productive CBM basins such as the Black Warrior in Alabama, the Cherokee Basin in Oklahoma and the Raton Basin in New Mexico and Colorado.

Through 2001, TXCO re-entered, and successfully completed, 34 CBM wells on its Comanche lease. Based on the encouraging results of its exploratory core and well drilling program for CBM gas, TXCO continued its CBM activities in 2002 by advancing the project into its preliminary development stage, justifying the costs of drilling optimized wells.

Optimized wells are wells drilled using air-drilling techniques and completed selectively with advanced fracture stimulation techniques designed to maximize coal formation response. Additionally, the wells are completed with larger-diameter tubulars, allowing for more rapid dewatering. During 2002, the Company drilled five such wells. After fracture stimulating two of the five wells, production from the new wells increased over 40% to 57 Mcfd with a corresponding drop in water production. While the actual CBM producing amounts are not significant in themselves, the marked increase in post-fracture volumes is encouraging in confirming the applicability of the optimized drilling technique. The Company is reviewing other techniques to apply to the remaining three optimized wells.

TXCO proceeds with the dewatering phase of its Olmos/coalbed methane project. The large volume of water typically produced in the dewatering phase of CBM production normally represents a significant component of the operating expense in the production of CBM gas. TXCO has engineered a synergistic water disposal cost reduction program to dispose of the CBM water into the underlying San Miguel formation discussed earlier in this section. At year-end 2004, the net field production exit rate from 31 wells was 82 Mcfd of natural gas and 1,084 barrels of water per day ("BWPD") down from 154 Mcfd and 1,359 BWPD from 36 wells at December 31, 2003. Gas production declined in 2004 as severe weather, flooding, and the resultant power outages caused the wells to go off-line on multiple occasions during the year. When the dewatering process is interrupted, the water inflows back in to the coal zone and progress on the dewatering is set back significantly.

The Company believes that the next phase of this project will require an additional 25 to 50 wells, during which the Company hopes to establish economic gas production quantities.

During 2004, TXCO management actively engaged in a strategy to accelerate the activity in the CBM project. TXCO initiated discussions with various potential partners in order to attract a joint venture partner to employ capital to drill new CBM wells. Subsequent to December 31, 2004, TXCO entered into an asset exchange agreement in properties including the CBM acreage that reduces our interest in a portion of this project to 50% while significantly increasing the acreage prospective for CBM. See the discussion of this transaction in the "Maverick Basin" section. Although there are no new CBM wells included in the 2005 CAPEX budget, the Company expects that this project will add significant reserves in the coming years.

Williston Basin

Through 2004, the Company continued to evaluate all of its Williston Basin lease obligations, making lease extension payments on a selective basis, emphasizing those leases with particular geologic attributes or with adequate remaining primary lease terms. Consistent with Management's strategy to focus exploration efforts and resources on the development of its core producing area in South Texas, TXCO has maintained marketing efforts offering its remaining Williston Basin holdings to other exploration companies with a focus on this area.

In mid-2003, Luff Exploration Company ("Luff") formed the East Harding Springs Red River Unit ("Unit"), located in Harding County, South Dakota, with the primary objective to waterflood the B zone of the Red River formation. As a result of contributing acreage to the Unit, TXCO earned a 0.58% WI and 0.49% NRI in the Unit. In 2003, Luff drilled two horizontal laterals in an existing well, and a new horizontal well targeting the Red River B zone to utilize both wells as injection wells. While not expected, both wells encountered commercial quantities of oil.

During 2004, the Company participated in the drilling of one new well and two re-entries in the Red River formation. The new well and one re-entry are located in the Unit described above (0.58% WI), while the other re-entry was in a North Dakota well (30% WI). All three wells are currently producing oil. TXCO participated in one re-entry in North Dakota during 2003. At year-end 2004, Williston Basin had a net field production exit rate of 126 BOE. By comparison the net field production exit rate at year-end 2003 was 100 BOE net.

At December 31, 2004, TXCO retained approximately 83,500 net acres in the Williston Basin**.** No funds have been included in the 2005 CAPEX for drilling in this basin.

PRINCIPAL PRODUCTS AND COMPETITION

The Company's principal products are natural gas and crude oil. The production and marketing of oil and gas are affected by a number of factors that are beyond the Company's control, the effects of which cannot be accurately predicted. These factors include crude oil imports, actions by foreign oil-producing nations, the availability of adequate pipeline and other transportation facilities, the marketing of competitive fuels and other matters affecting the availability of a ready market, such as fluctuating supply and demand. Prior to 2003, the Company sold all of its oil and gas under short-term contracts that can be terminated with 30 days notice, or less. None of the Company's production was sold under long-term contracts with specific purchasers. Consequently, the Company was able to market its oil and gas production to the highest bidder each month. During 2003 the Company participated in a fixed-price contract for approximately 30% of the its net gas production rate at year-end 2002 through year-end 2003. As a forward sale of part of its physical production, the Company was able to lock-in relatively high prices, by historical standards, without being subject to risks associated with derivative instruments. The Company sold all of its production to the highest bidder each month for January through September of 2004.

In October 2004, the Company entered into financial price hedges with Macquarie Bank Ltd. for 15,000 BO and 140,000 MMBtu of gas, each on a monthly basis for a twelve-month period. These hedges are in the form of ratio swaps (the Swaps) and provide floor prices of $39.10 per BO and $5.37 per MMBtu on a basis adjusted to Houston Ship Channel prices. These hedge volumes represent approximately 56% of the Company's average monthly sales volumes for all of 2004 and approximately 53% of the average monthly sales volumes for the fourth quarter of 2004. The Swaps also allow the Company to participate in 75% of potential upside price movement above the floor levels. In early March 2005, the Company entered into additional financial price hedges with Coral Energy Holdings, L.P. (an affiliate of Shell Oil) for 15,000 BO and 140,000 MMBtu of gas, each on a monthly basis for November 2005 through October 2006. These hedges are in the form of fixed price swaps with prices of $49.40 per BO and $6.83 per MMBtu on a basis adjusted to Houston Ship Channel prices. The Company did not elect hedge accounting treatment for these agreements. The changes in market value of the Swaps are recorded on the income statement each period as Derivative Fair Value Gains or Losses and may impact the volatility of reported earnings.

The Company operates and directs the drilling of oil and gas wells and participates in non-operated wells. As operator, it contracts service companies, such as drilling contractors, cementing contractors, etc., for specific tasks. In some non-operated wells, the Company participates as an overriding royalty interest owner.

During 2004, three purchasers of the Company's oil and gas production and other natural gas sales accounted for 14%, 13% and 13% of total revenues. In the event any of these major customers declined to purchase future production, the Company believes that alternative purchasers could be found for such production at comparable prices.

The oil and gas industry is highly competitive in the search for and development of oil and gas reserves. The Company competes with a substantial number of major integrated oil companies and other companies having significantly greater financial resources and manpower than the Company. These competitors, having greater financial resources than the Company, have a greater ability to bear the economic risks inherent in all phases of this industry. In addition, unlike the Company, many competitors produce large volumes of crude oil that may be used in connection with their operations. These companies also possess substantially larger technical staffs, which puts the Company at a significant competitive disadvantage compared to others in the industry.

EMPLOYEES

As of December 31, 2004, the Company employed 47 full-time employees including management. The Company believes its relations with its employees are good. None of the Company's employees are covered by union contracts.

GENERAL REGULATIONS

Both state and federal authorities regulate the extraction, production, transportation, and sale of oil, gas, and minerals. The executive and legislative branches of government at both the state and federal levels have periodically proposed and considered proposals for establishment of controls on alternative fuels, energy conservation, environmental protection, taxation of crude oil imports, limitation of crude oil imports, as well as various other related programs. If any proposals relating to the above subjects were to be enacted, the Company is unable to predict what effect, if any, implementation of such proposals would have upon the Company's operations. A listing of the more significant current state and federal statutory authority for regulation of the Company's current operations and business are provided herein below.

Federal Regulatory Controls

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938 (the "NGA"), the Natural Gas Policy Act of 1978 (the "NGPA") and the regulations promulgated thereunder by the Federal Energy Regulatory Commission ("FERC"). Maximum selling prices of certain categories of natural gas sold in "first sales," whether sold in interstate or intrastate commerce, were regulated pursuant to the NGPA. On July 26, 1989, the Natural Gas Wellhead Decontrol Act (the "Decontrol Act") was enacted, which removed, as of January 1, 1993, all remaining federal price controls from natural gas sold in "first sales." The FERC's jurisdiction over natural gas transportation was unaffected by the Decontrol Act.

Commencing in April 1992, the FERC issued Order Nos. 636, 636-A and 636-B (collectively "Order No. 636"), which required interstate pipelines to provide transportation, separate or "unbundled," from the pipelines' sales of gas. Although Order No. 636 did not directly regulate the Company's activities, it fostered increased competition within all phases of the natural gas industry.

In December 1992, the FERC issued Order No. 547, governing the issuance of blanket marketer sales certificates to all natural gas sellers other than interstate pipelines. The order applies to non-first sales that remain subject to the FERC's NGA jurisdiction. The FERC Order No. 547, in tandem with Order No. 636, has fostered a competitive market for natural gas by giving natural gas purchasers access to multiple supply sources at market-driven prices. Order No. 547 has increased competition in markets in which the Company's natural gas is sold. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach pursued by the FERC and Congress will continue.

State Regulatory Controls

In each state where the Company conducts or contemplates conducting oil and gas activities, such activities are subject to various state regulations. In general, the regulations relate to the extraction, production, transportation and sale of oil and natural gas, the issuance of drilling permits, the methods of developing new production, the spacing and operation of wells, the conservation of oil and natural gas reservoirs and other similar aspects of oil and gas operations. In particular, the State of Texas (where the Company has conducted the majority of its oil and gas operations to date) regulates the rate of daily production allowable from both oil and gas wells on a market demand or conservation basis. At the present time, no significant portion of the Company's production has been curtailed due to reduced allowables. The Company knows of no proposed regulation that will significantly impede its operations.

Environmental Regulations

The Company's extraction, production and drilling operations are subject to environmental protection regulations established by federal, state, and local agencies. To the best of its knowledge, the Company believes that it is in compliance with the applicable environmental regulations established by the agencies with jurisdiction over its operations. The Company is acutely aware that the applicable environmental regulations currently in effect could have a material detrimental effect upon its earnings, capital expenditures, or prospects for profitability. The Company's competitors are subject to the same regulations and therefore, the existence of such regulations does not appear to have any material effect upon the Company's position with respect to its competitors. The Texas Legislature has mandated a regulatory program for the management of hazardous wastes generated during crude oil and natural gas exploration and production, gas processing, oil and gas waste reclamation and transportation operations. The disposal of these wastes, as governed by the Railroad Commission of Texas, is becoming an increasing burden on the industry. The Company's leases in Montana, North Dakota and South Dakota are subject to similar environmental regulations including archeological and botanical surveys as most of the leases are on federal and state lands.

Federal and State Tax Considerations

Revenues from oil and gas production are subject to taxation by the state in which the production occurred. In Texas, the state receives a severance tax of 4.6% for oil production and 7.5% for gas production. North Dakota production taxes typically range from 9.0% to 11.5% while Montana's taxes range up to 17.2%. These high percentage state taxes can have a significant impact upon the economic viability of marginal wells that the Company may produce and require plugging of wells sooner than would be necessary in a less arduous taxing environment. For Federal Income Tax purposes, the Company has remaining net operating loss carryforwards ("NOLs") of $3.6 million that may be used to offset future taxable income. The NOLs are scheduled to expire in stages from 2007 to 2018.

CERTAIN BUSINESS RISKS

Reliance on Estimates of Proved Reserves and Future Net Revenues: Depletion of Reserves

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and the timing of development expenditures, including many factors beyond the control of the Company. The reserve data set forth in this report represents only estimates. In addition, the estimates of future net revenues from proved reserves of the Company and the present value thereof are based on certain assumptions about future production levels, prices and costs that may not prove to be correct over time. In particular, estimates of crude oil and natural gas reserves, future net revenue from proved reserves and the present value of proved reserves for the crude oil and natural gas properties described in this report are based on the assumption that future crude oil and natural gas prices remain constant based on prices in effect at December 31, 2004.

The following table details the average prices used for these estimates for the respective dates presented:

	12/31/04	12/31/03	12/31/02	12/31/01
Gas price per Mcf	$ 6.06	$ 5.77	$ 4.90	$ 2.72
Oil price per Bbl	$41.15	$30.06	$28.71	$17.31

Any significant variance in these assumptions could materially affect the estimated quantity and value of reserves set forth herein. See "Management's Discussion and Analysis of Financial Condition and Results of Operations" "Capital Resources and Liquidity" section and "Properties".

Depletion of Reserves

The rate of production from crude oil and natural gas properties declines as reserves are depleted. Except to the extent the Company acquires additional properties containing proved reserves, conducts successful exploration and development activities or through engineering studies identifies additional behind-pipe zones or secondary recovery reserves, the proven reserves of the Company will decline as reserves are produced. Future crude oil and natural gas production is highly dependent upon the Company's level of success in finding or acquiring additional reserves.

Title to Properties

As is customary in the crude oil and natural gas industry, the Company performs a preliminary title investigation before acquiring undeveloped properties that generally consists of obtaining a title report from outside counsel or due diligence reviews by independent landmen. The Company believes that it has satisfactory title to such properties in accordance with standards generally accepted in the oil and gas industry. A title opinion from counsel is generally obtained before the commencement of any drilling operations on such properties. The Company's properties are subject to customary royalty interests, liens incidental to operating agreements, liens for current taxes and other burdens, none of which the Company believes materially interferes with the use of, or affects the value of, such properties.

Net Income or Loss

In its recent history, the Company has recorded both net income and net losses. For the year ended December 31, 2004, the Company recorded a net income of $2,796,828; for the year ended December 31, 2003, the Company recorded a net income of $40,877; for the year ended December 31, 2002, the Company recorded a net loss of $310,970. There can be no assurance that the Company will avoid net losses in the future.

Operating Hazards; Uninsured Risks

The nature of the crude oil and natural gas exploration and production business involves certain operating hazards such as crude oil and natural gas well blowouts, explosions, formations with abnormal pressures, cratering and crude oil spills and fires. Any of these could result in damage to or destruction of crude oil and natural gas wells, destruction of producing facilities, damage to life or property, suspension of operations, environmental damage and possible liability to the Company. In accordance with customary industry practices, the Company maintains insurance against some, but not all, of such risks and some, but not all, of such losses. The occurrence of such an event not fully covered by insurance could have a material adverse effect on the financial condition and results of operations of the Company.

Substantial Capital Requirements

The Company makes, and will continue to make, substantial capital expenditures for the acquisition, exploitation, development, exploration, and production of crude oil and natural gas reserves. Historically, the Company has financed these expenditures from available cash flow from operations, supplemented by debt and equity offerings and the sale of interests in its properties. The Company is hopeful that it will continue to be able to obtain sufficient capital to finance planned capital expenditures. However, if revenues decrease because of lower crude oil and natural gas prices, operating difficulties or declines in reserves, the Company may have limited ability to finance planned capital expenditures in the future. Therefore, there can be no assurance that additional debt or equity financing or cash generated by operations will be available to meet its capital requirements.

Certain Corporate Defensive Matters

The Company's Articles of Incorporation, Bylaws and Delaware law contain provisions that may have the effect, together or separately, of delaying, deferring, or preventing a change in control of the Company. In particular, the Company may issue up to 10 million shares of preferred stock, Series A, with rights and privileges that could be senior to its outstanding common stock. The Company's Certificate of Incorporation and Bylaws provide, among other things, for advance notice of stockholder's proposals and director nominations, and provide for non-cumulative voting in the election of Directors.

In 2000, the Company's Board of Directors adopted a Stockholder Rights Plan under which uncertificated preferred stock purchase rights were distributed as a stock dividend to its common shareholders at a rate of one right for each share of common stock held of record as of July 19, 2000. Unless previously redeemed by the Company, the rights will expire in June 2010. The Rights Plan is designed to enhance the Board's ability to prevent an acquirer from depriving stockholders of the long-term value of their investment and to protect shareholders against attempts to acquire the Company by means of unfair or abusive takeover tactics that have been prevalent in many unsolicited takeover attempts.

In 2001, a majority of the Company's shareholders approved an amendment to its Certificate of Incorporation providing for the establishment of a classified board of directors. The classified board provision established three classes of directors, with each class to be elected for a three-year term on a staggered basis. The classified board provision is intended to promote management continuity and stability and to afford time and flexibility in responding to unsolicited tender offers.

In 2003, TXCO entered into Change in Control letter agreements with each of its employees. Certain payout-related terms in these agreements were amended during 2004. These agreements provide payment, to each employee, of two months' base pay for each year of their service, with a minimum payout of six months salary, within one year after a change of control as defined in the agreements, or earlier in the event of the employees' dismissal or demotion. Payments to certain officers of TXCO are a set multiple of their annual salary rather than fluctuating with their years of service.

Available Information

The Company files annual, quarterly and current reports, proxy statements and other information with the Securities and Exchange Commission ("SEC"). These filings are available free of charge through our internet website at www.txco.com as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

ITEM 2. PROPERTIES

PHYSICAL PROPERTIES

The Company's administrative offices are located at 500 North Loop 1604 East, Suite 250, San Antonio, Texas. These offices, consisting of approximately 13,500 square feet, are leased through August 2007 at $22,215 per month with annual escalations each September 1.

All the Company's oil and gas properties, reserves, and activities are located onshore in the continental United States. There are no quantities of oil or gas subject to long-term supply or similar agreements with foreign government authorities.

Proved Reserves, Future Net Revenue and Present Value of Estimated Future Net Revenues

The following unaudited information as of December 31, 2004, relates to the Company's estimated proved oil and gas reserves, estimated future net revenues attributable to such reserves and the present value of such future net revenues using a 10% discount factor ("PV-10 Value"), as estimated by the Company's independent reservoir engineering firm, DeGolyer and MacNaughton, a Dallas-based worldwide petroleum consulting firm. Estimates of proved developed oil and gas reserves attributable to the Company's interest at December 31, 2004, 2003 and 2002 are set forth in Notes to the Audited Consolidated Financial Statements included in this Annual Report on Form 10-K. The estimates of proved reserves for 2003 and 2002 were prepared by Netherland, Sewell & Associates, Inc. of Dallas, Texas.

The PV-10 Value is based on the estimated future net revenues, as prepared by the Company's independent reservoir engineering firm in accordance with SFAS No. 69. Accordingly, the estimate is net of estimated production, future development costs and future outflows related to asset retirement obligations, and do not give effect to non-property related expenses, such as corporate general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization. PV-10 Value differs from the standardized measure by the present value of estimated income taxes.

Oil prices used in PV-10 Value are based on a December 31, 2004 Flint Hills South Texas Light Crude posted price of $38.50 per barrel, adjusted by lease for quality, transportation fees, regional price differentials and fixed price contracts for the life of each respective contract. Gas prices used in PV-10 Value are based on a December 31, 2004 Houston Ship Channel spot market price of $5.815 per MMBtu, adjusted by lease for energy content, transportation fees, and regional price differentials. Oil and gas prices are held constant. While the methodology is the same across companies, the reference price and adjustments will vary between companies based on conditions in their production areas.

Because PV-10 Value may be considered a non-GAAP financial measure as defined in Item 10(e) of Regulation S-K, the Company will include in its future filings with the SEC, the disclosures required by Item 10(e) of Regulation S-K with respect to PV-10 Value, including the following reconciliation to the most directly comparable GAAP financial measure (Standardized Measure), and the following discussion of how management uses the measure and why it is useful to investors.

Management believes that the presentation of PV-10 Value is appropriate in its filings and is relevant and useful to its investors because it presents the discounted future net cash flows attributable to its proved reserves prior to taking into account corporate future income taxes and it is a useful measure for evaluating the relative monetary significance of the Company's oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of the Company's reserves to other companies. Management uses this measure when assessing the potential return on investment related to its oil and natural gas properties. The PV-10 Value and the standardized measure of discounted future net cash flows are not intended to represent the current market value of the estimated oil and natural gas reserves owned by the Company.

Detail of PV-10 and Reconciliation to Standardized Measure

PV-10 Value of Estimated Future Net Revenues, by year:	
2005	$19,675,000
2006	11,744,000
2007	12,693,000
2008	7,760,000
2009	7,454,000
Thereafter	21,442,000
Total PV-10 value	$80,768,000
Less present value of estimated income taxes	15,306,000
Standardized measure	$65,462,000

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas liquids and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. No reserve estimates have been filed with or included in reports to any federal or foreign government authority or agency, other than the SEC, since the Company's latest Form 10-K filing.

SEC PV-10 Reserves at December 31,	2004 Volumes	2004 Mix *	2003 Volumes	2003 Mix *	2002 Volumes	2002 Mix *
Natural gas (Bcf)	17.7	47%	15.6	55%	14.7	63%
Oil (MMBbls)	3.4	53%	2.1	45%	1.5	37%
Natural gas equivalent (Bcfe) *	37.9	100%	28.4	100%	23.5	100%

* For percent change and natural gas equivalent calculations, one barrel of oil is approximately equivalent to six Mcf of natural gas.

Sales Volumes

The following table summarizes the Company's net oil and gas production, average sales prices, and average production costs per unit of production for the periods indicated. With respect to newly drilled wells, there can be no assurance that current production levels can be sustained. Depending upon reservoir characteristics, such levels of production could decline significantly.

	Years Ended December 31, 2004	2003	2002
Oil:			
Sales volumes (Bbl)	321,000	454,000	314,000
Average sales price per Barrel	$38.72	$28.30	$24.56
Gas:			
Sales volumes (Mcf)	2,975,000	2,108,000	2,487,000
Average price per Mcf	$5.96	$5.48	$3.35
Average cost per equivalent Mcf (1)	$1.44	$1.22	$1.16

(1) Oil and gas were combined by converting oil to gas Mcf equivalent on the basis of 1 barrel of oil = 6 Mcf of gas. Production costs include direct lease operations and production taxes.

Producing Properties - Wells and Acreage

The following table sets forth the Company's producing wells and developed acreage assignable to such wells for the last three fiscal years:

	Developed Acreage *		Productive Wells					
			Oil		Gas		Total	
Year Ended	Gross	Net	Gross	Net	Gross	Net	Gross	Net
12/31/04	43,850	25,120	291	255.43	201	146.92	492	402.35
12/31/03	35,230	20,423	276	242.74	162	120.49	438	363.23
12/31/02	25,350	14,526	168	148.66	112	83.45	280	232.11

* As of mid-February 2005, gross acreage was approximately 727,000 (490,000 net).

Productive wells consist of producing wells and wells capable of production, including shut-in wells and wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities.

A "gross well" or "gross acre" is a well or acre in which a working interest is held. The number of gross wells or gross acres is the total number of wells or acres in which working interests are owned. A "net well" or "net acre" is deemed to exist when the sum of fractional ownership interest in gross wells or gross acres equals one. The number of net wells or net acres is the sum of fractional working interests owned in gross wells or gross acres expressed as whole numbers and fractions thereof.

Undeveloped Acreage

As of December 31, 2004, the Company owned, by lease or in fee, the following undeveloped acres:

United States	Gross Acres	Net Acres	Estimated 2005 Delay Rentals
Texas (1)	491,289	428,157	$ 242,181
North Dakota	81,057	80,954	171,836
South Dakota	2,637	1,635	991
Montana	960	960	3,840
Total	575,943	511,706	$ 418,848

(1) In February 2005, an asset exchange agreement added 174,000 gross acres (69,500 net) and $307,000 in estimated 2005 delay rentals.

Six Texas leases totaling approximately 83,460 gross acres contain varying requirements to drill a well every 90 to 180 days to keep the respective lease in effect. The Company is presently drilling under the terms of the leases and expects the leases to remain in force by continuous development during the year.

Drilling Activity

The following tables set forth the Company's drilling activity for the last three years:

	2004		2003		2002	
Completions Summary:	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Drilling Well Completions:						
Oil Wells (1)	24	21.43	29	26.53	10	5.53
Gas Wells (1)	22	11.60	19	11.14	15	11.48
Dry Holes	-	-	1	1.00	1	.63
Total Drilling Wells Completed	46	33.03	49	38.67	26	17.64
Re-entries Completed:						
Oil Wells	3	1.30	8	5.68	4	4.00
Gas Wells	3	2.98	0	0.00	1	1.00
Dry Holes	-	-	-	-	-	-
Total Re-entries Completed	6	4.28	8	5.68	5	5.00
Wells Completed in Year	52	37.31	57	44.35	31	22.64

(1) Includes one well, each, spudded during December 2003 and completed in 2004.

	2004		2003		2002	
In-Progress Recap:	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Beginning In Progress	39	30.37	22	16.23	12	11.64
Less - Completions:						
Oil Wells	1	1.00	-	-	-	-
Gas Wells	3	1.50	2	0.50		
Less - In Progress Wells Re-entered, Not Completed	-	-	4	2.50	1	1.00
Add - Spud Not Finished - New	16	12.19	22	16.14	11	5.59
- Re-entries	3	1.80	1	1.00	-	-
Ending In-Progress	54	41.86	39	30.37	22	16.23

2004 Activity:

During 2004, TXCO participated in 69 wells, including new drilling of 60 (43.72 net) wells and the re-entry of nine (6.08 net) existing wells. The Company operated 48 (38.00 net) of the 69 newly drilled wells. Of the current year drilling wells, 16 (12.19 net) remained in progress at December 31, 2004. Six of the re-entered wells were put on production in 2004, while the remaining three re-entries are pending reevaluation for recompletion or stimulation. Two of the six re-entries that are now producing were on wells included as in-progress at the beginning of the year. Additionally, two wells spudded during 2003 were completed and put on production in early 2004.

At December 31, 2004, in progress wells include 16 development wells spudded in 2004, three re-entries spudded in 2004, and 35 wells that remain in progress from the beginning of 2004. The 35 remaining prior year in-progress wells include nine CBM wells drilled in 2000 and 2001, whose completion is pending development of the coal field, and 26 other wells that are being evaluated for recompletion as horizontal wells or into other zones, including 13 in the Glen Rose porosity interval.

2003 Activity: TXCO participated in 80 wells, including new drilling of 71 (54.82 net) wells and the re-entry of nine (6.68 net) existing wells, during 2003. Of the 71 newly drilled wells, the Company operated 56 (48.25 net) wells. Of the current year drilling wells, 22 (16.14 net) remained in progress at December 31, 2003. Eight of the re-entered wells were put on production in 2003, while the remaining well is pending reevaluation for recompletion or stimulation.

Year-end 2003 in progress wells include the 22 wells spudded in 2003, one re-entry begun in 2003, and 16 wells that remain in progress from the beginning of 2003. The 16 remaining prior year in-progress development wells include the nine CBM wells previously mentioned, and seven other wells that are being evaluated for recompletion as horizontal wells or into other zones.

2002 Activity: The Company began 2002 with 12 (11.64 net) wells in progress from 2001. During 2002, the Company initiated 41 (27.23 net) new drilling / re-entry wells. These wells resulted in 16 (12.48 net) gas wells, 14 (9.53 net) oil wells, 1 (.63 net) dry well and 22 (16.23 net) wells remained in progress at December 31, 2002.

During 2002 the Company re-entered four (four net) existing wells, of which all were put on production in 2002. Included in 2002 re-entry activity was one CBM gas well that was in progress at year-end 2001.

Additional information regarding the Company's properties is contained in Item 1 of this Form 10-K and in the Consolidated Financial Statements and Notes thereto under Item 8 of this Form 10-K.

Gas Gathering System

During 2004, TXCO entered into an agreement to purchase a 6.1-mile portion of an existing, privately owned pipeline to serve the northwest portion of TXCO's lease block at a net price of $207,000. This purchase, and an associated five-year lease on an additional 1.7-mile segment of existing pipeline, expanded our pipeline infrastructure to bring new Burr lease gas production to market. These transactions gave the Company control of approximately 91 miles of pipeline in the Maverick Basin.

The Company acquired its gathering system in 2002 to enhance its infrastructure in the Maverick Basin. The initial system included a 69-mile natural gas pipeline, a compressor station with three compressors and three dehydrators that allow the system to have maximum deliverable capacity of 35 MMcfd of which one-third is currently utilized. The pipeline begins approximately 12 miles north of Eagle Pass, Texas, in Maverick County, and runs to Carrizo Springs, Texas, in Dimmit County, where it terminates at an Enterprise Hydrocarbons L.P. (Enterprise) delivery point, where the gas is processed and delivered to the Enterprise/GulfTerra Pipeline System. Also, in 2002, the Company acquired an additional 10 miles of pipeline from TXCO's 62.5%-owned subsidiary, the Paloma Pipeline L.P., as well as constructed and placed in service a 3-mile pipeline extension to connect the Company's growing Chittim lease production to the pipeline system.

The Company's gas gathering system transports its production to various markets. It also transports production for other owners at a set rate per MMbtu. It sells gas at several points along the system with a significant portion being delivered to purchasers through the Enterprise/Gulf Terra Pipeline System. Enterprise processes the gas delivered through it to remove natural gas liquids and markets the liquids separately. The Company receives a share of the revenues for the liquids. Natural gas pricing fluctuations are reflected at the wellhead for the Company's operated gas properties. The following table summarizes the Company's gas marketing sales volumes, average sales prices, and average transportation costs per MMbtu for the periods indicated. There can be no assurance that current access levels to third party pipelines and processing facilities can be sustained. The following table reflects the growth in residue gas and natural gas liquids sales:

	Years Ended December 31,		
	2004	2003	2002
Residue gas and NGL sales volumes (MMbtu)	4,062,000	2,935,000	656,000
Average sales price per MMbtu	$6.69	$5.01	$3.68

ITEM 3. LEGAL PROCEEDINGS

The Company is not involved in any matters of litigation.

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

No matter was submitted to a vote of the security holders of the Company during the fourth quarter of 2004.

PART II

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

The following is a range of high and low bid prices for the Company's common stock for each quarter presented based upon bid prices reported by the National Association of Securities Dealers Quotations system under the call symbol "TXCO":

	Range of Bid Prices	
Quarter Ended:	**High**	**Low**
December 2004	$ 6.60	$ 3.98
September 2004	4.61	3.68
June 2004	4.38	3.44
March 2004	7.19	3.89
December 2003	$ 6.75	$ 4.55
September 2003	6.24	4.04
June 2003	4.57	2.80
March 2003	3.78	2.62

As of March 4, 2005, there were approximately 1,144 holders of record of the Company's Common Stock. The transfer agent for the Company is the American Stock Transfer & Trust Company, 59 Maiden Lane, New York, New York 10038. The Company has not paid any cash dividends on its Common Stock in past years and does not expect to do so in the foreseeable future.

ITEM 6. SELECTED FINANCIAL DATA

The following selected financial information is derived from and qualified in its entirety by the Audited Consolidated Financial Statements of the Company and the Notes thereto as set forth in this Annual Report on Form 10-K commencing on page F-1.

	Year Ended December 31				
(In thousands, except per share data)	2004	2003	2002	2001	2000
Operating revenues	$ 57,735	$ 39,545	$ 18,958	$ 13,759	$ 14,361
Net income (loss)	2,797	41	(311)	(50)	6,762
Basic income (loss) per common share	0.11	0.00	(0.02)	(0.00)	0.39
Net cash provided by operating activities	16,447	15,158	7,389	8,564	6,530
Net cash used by investing activities	(37,718)	(36,282)	(27,655)	(11,895)	(6,439)
Net cash provided (used) by financing activities	20,208	24,971	20,580	(548)	2,426
Total Assets	114,237	84,206	53,036	29,843	29,206
Long-term obligations	31,654	28,909	7,217	862	1,195
Stockholders' Equity	$ 65,682	$ 42,792	$ 36,970	$ 23,057	$ 23,322
Weighted average shares outstanding - Basic	26,066	20,781	19,081	17,441	17,242

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

Forward-looking Statements: Statements in this Form 10-K which are not historical, including statements regarding TXCO's or management's intentions, hopes, beliefs, expectations, representations, projections, estimations, plans or predictions of the future, are forwarding-looking statements and are made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. Such statements include those relating to expected drilling plans, including the timing, category, number, depth, cost and/or success of wells to be drilled, expected geological formations or the availability of specific services or technologies. It is important to note that actual results may differ materially from the results predicted in any such forward-looking statements. Investors are cautioned that all forward-looking statements involve risks and uncertainty, including without limitation, the costs of exploring and developing new oil and natural gas reserves, the price for which such reserves can be sold, environmental concerns affecting the drilling of oil and natural gas wells, as well as general market conditions, competition and pricing. Please refer to TXCO's Securities and Exchange Commission filings for additional information. This and all TXCO's previously filed documents are on file at the Securities and Exchange Commission and can be viewed on TXCO's website at www.txco.com. Copies are available from the Company without charge.

OVERVIEW

The following is a discussion of the Company's financial condition and results of operations. This discussion should be read in conjunction with the Financial Statements of the Company and Notes thereto.

The Exploration Company is an independent oil and gas enterprise with interests primarily in the Maverick Basin in Southwest Texas. The Company has a consistent record of long-term growth in its proved oil and gas reserves, leasehold acreage position, production and cash flow through its established exploration and development programs. Its business strategy is to build shareholder value by acquiring undeveloped mineral interests and internally developing a multi-year drilling inventory through the use of advanced technologies, such as 3-D seismic and horizontal drilling. The Company accounts for its oil and gas operations under the successful efforts method of accounting and trades its common stock on the Nasdaq Stock Market℠ under the symbol "TXCO."

The Company currently has four drilling rigs under operation on its extensive 727,000-acre position in the Maverick Basin, targeting at least three separate formations for the production of oil and natural gas. Completions in 2004 included 24 gas and 25 oil wells, which included two wells spud in 2003 and six re-entries during 2004, while 15 wells spud during the year remained in progress at year-end. Current emphasis is on the Georgetown, San Miguel and Glen Rose formations. The 2005 capital expenditures budget includes funds for 59 new wells (35 in the Georgetown formation, six in the Glen Rose formation and 10 in the San Miguel waterflood) and four re-entries, as well as funds for seismic and lease acquisitions.

Due to the number of promising prospects on our Maverick Basin acreage, and higher oil and gas prices, drilling activity remained high during 2004. (For further discussion of this activity, see the "Principal Areas of Activity" and "Drilling Activity" sections of this Form 10-K). The resulting increased expenditures should translate into continued increases to reserves as adequate production history is established. Revenues and credit capacity for future activity should continue to grow as the result of the increased drilling activity. Recognition of additional reserves on newly drilled wells requires a period of sustained production, causing a delay between the expenditures and the recording of reserves.

TXCO reported net income of $2.8 million or $0.11 per basic share, $0.10 per diluted share for the year ended December 31, 2004, compared to a net income of $40,877 or $0.00 per basic and diluted share for the prior year. Major contributors to this improvement were higher average sales prices, increased margin on gas gathering activities, and increased production on an equivalent unit basis. Offsetting these improvements were increases in lease operating expenses, depreciation and depletion, and interest expense. These factors are discussed in the Results of Operations section.

TXCO continued its ongoing trend of strong annual reserve growth in 2004 as it recorded net proved reserve additions of 9.5 Bcfe. Combined with annual production of 4.9 Bcfe, TXCO's gross reserve additions for the year were 14.4 Bcfe. Estimated year-end proved oil and gas reserves were a record 37.9 Bcfe, a third above its 28.4 at year-end 2003. The Company achieved a 295 percent all-source reserve replacement rate in 2004. Positive cash flow provided from operations totaled $16.4 million, an 8.5% increase over the prior year. The following table illustrates key features of the Company's continuous development over the four fiscal years presented.

Development:	2004	2003	2002	2001
	Year Ended December 31,			
No. of new oil wells completed	24	37	14	9
No. of new gas wells completed	22	19	16	54
No. of new oil wells purchased	-	-	94	-
Gas sales (MMcf)	2,975	2,108	2,487	2,673
Gas reserve additions from drilling (MMcf)	6,432	5,037	5,103	8,664
Oil sales (MBbl)	321	454	314	50
Oil reserves additions from drilling (MBbl)	1,396	1,115	600	66
Gas equivalent sales (Bcfe)	4.90	4.83	4.37	2.97
Reserve additions (Bcfe)				
Drilling	14.81	11.73	8.70	9.06
Revisions of previous estimates	(0.92)	(2.72)	2.44	1.02
Purchased	0.56	0.68	4.04	-
Total reserves added (Bcfe) (1)	14.45	9.69	15.18	10.08
Reserve replacement rate (2)				
Drill bit	283%	186%	255%	339%
Drill bit plus purchases (all sources)	295%	200%	347%	339%
Non-developed Texas acreage leased	491,289	479,761	408,992	372,000
Non-developed Williston Basin acreage leased	84,654	91,804	91,804	105,000

(1) Make-up of proved developed reserves at year-end 2004: 56% gas, 44% oil.
(2) The reserve replacement ratio is calculated by dividing proved reserve additions, which includes extensions and discoveries, revisions to previous estimates and reserves purchased, as the numerator, by the sales volumes for the year as the denominator. For the drill bit only ratio, any purchased reserves are excluded from the numerator. See discussion regarding uncertainties included in Part I, Item 1 of this Form 10-K. See the discussion below regarding how management uses this information and potential time horizons for realization of these reserves.

In December 2004, TXCO retained Raymond James & Associates to assist in actively pursuing strategic alternatives designed to enhance shareholder value, including a merger or sale of the Company. No formal decisions have been made and no agreements have been reached at this time. There can be no assurances that any particular alternative will be pursued or that any transaction will occur, or on what terms.

Reserve Replacement

Historically, the Company has added proved reserves due to both drilling and acquisition activities. Management believes that TXCO will continue to add reserves each year, however, external factors beyond its control, such as governmental regulations and commodity market factors, could limit our ability to drill wells and acquire proved properties in the future. The Company calculates and analyzes reserve replacement ratios to use as benchmarks against its competitors. Oil and gas companies are judged by the investing public and management by how effective they are in replacing annual production, hence the need for said ratios. These ratios are limited in use by the inherent uncertainties in the reserve estimation process and other factors. TXCO's reserve additions for each year are estimates. Reserve volumes can change over time, and therefore cannot be absolutely known or verified until all volumes have been produced and a cumulative production total for a well or field can be calculated. Many factors will impact the ability to access these reserves, such as availability of capital, new and existing government regulations, competition within the industry, the requirement of new or upgraded infrastructure at the production site, and technological advances. See the "Certain Business Risks" section in Part I, Item 1 for further discussion of risks and uncertainties related to reserves.

The reserve report, prepared by independent reservoir engineers and used for both the PV-10 Value and the standardized measure, indicates the last date of production is estimated to be July 2073. However, as shown in the table in Item 2 of this Form 10-K, approximately 73% of that production is expected to be realized by year-end 2009.

CAPITAL RESOURCES AND LIQUIDITY

Liquidity is a measure of ability to access cash. The Company's primary needs for cash are for exploration, development and acquisitions of oil and gas properties, repayment of contractual obligations and working capital funding. TXCO has historically addressed its long-term liquidity requirements through cash provided by operating activities, the issuance of equity securities when market conditions permit, sale of non-strategic assets, and more recently through the Credit Facility and issuance of redeemable preferred stock. The prices for future oil and natural gas production and the level of production have significant impacts on operating cash flows and cannot be predicted with any degree of certainty. Management continues to examine alternative sources of long-term capital, including bank borrowings, the issuance of debt instruments, the sale of common stock, the sales of non-strategic assets, and joint venture financing. Availability of these sources of capital and, therefore, TXCO's ability to execute its operating strategy will depend upon a number of factors, some of which are beyond its control. Management believes that projected operating cash flows, cash on hand, and borrowings under the Credit Facility, will be sufficient to meet the requirements of TXCO's business. However, future cash flows are subject to a number of variables including the level of production and oil and natural gas prices. No assurances can be made that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures or that increased capital expenditures will not be undertaken. Actual levels of capital expenditures may vary significantly due to a variety of factors, including but not limited to drilling results, product pricing and future acquisition and divestitures of properties.

Bank Credit Facility

On June 30, 2004, the Company closed on a $50 million senior secured revolving credit facility with Guaranty Bank (the "Facility" or "credit facility"). The Facility has a three-year term expiring in 2007. It replaces TXCO's prior $25 million credit facility with Hibernia National Bank, which was scheduled to mature in 2006.

The credit facility is collateralized by all of the Company's proven oil and gas properties, with an initial borrowing base of $12.3 million, based on then current levels of TXCO's oil and gas reserves, and features semi-annual redeterminations. The borrowing base was increased to $20,750,000 in October 2004. Interest under the Facility will be as much as 0.25 percentage point less than the former credit agreement, based on, at TXCO's option, (a) the London Interbank Offered Rate (LIBOR) plus an applicable margin ranging from 2.00% to 2.50% or (b) prime plus an applicable margin ranging from 0.00% to 0.25%. At December 31, 2004, the Company had outstanding $17.1 million with a weighted average interest rate of 4.65%. An additional $3.3 million was advanced during January of 2005, bringing the total outstanding to $20.4 million.

When borrowing under the Facility exceeds 50% of the borrowing base, the Company is required to hedge volumes equivalent to 50% of its production at the inception of the Facility. The Company entered into financial price hedges in October 2004. In early March 2005, the Company entered into additional financial price hedges. The Company did not elect hedge accounting treatment for these agreements. Accordingly, the hedges are marked to market, and the change in market value is recorded on the income statement each period as Derivative Fair Value Gains or Losses impacting the volatility of reported earnings.

The Facility contains additional terms and conditions consistent with similarly positioned companies. These conditions include various restrictive covenants such as minimum levels of interest coverage, tangible net worth and current ratio, a maximum debt to EBITDAX ratio, restricting the payment of dividends other than the dividends payable under the redeemable preferred stock, and prohibiting a change of control or incurring additional debt. At December 31, 2004, the Company was not in compliance with the current ratio covenant. Concurrently, on March 15, 2005, TXCO received a commitment from Guaranty Bank to increase its borrowing base to $26.5 million from the previous amount of $20.75 million, as well as a waiver for the covenant requirement at December 31, 2004. The Company expects to be in compliance with this covenant at March 31, 2005 and subsequent periods. Accordingly, the Facility is classified as long-term.

2005 Capital Requirements Outlook

Overall: Management believes the Facility, along with the Company's positive cash flow from existing production and anticipated production increases from new drilling, will provide adequate capital to fund operating cash requirements and complete its scheduled exploration and development goals for 2005. TXCO expects to further increase its borrowing base commensurate with the expected growth of its proved oil and gas reserves throughout the base term of the Facility. Should product prices weaken, or expected new oil and gas production levels not be attained, the resulting reduction in projected revenues would cause the Company to re-evaluate its working capital options and would adversely affect the Company's ability to carry out its current operating plans.

The major components of the Company's plans, and the requirements for additional capital for 2005, include the following:

***Maverick Basin Activity*:** Initial capital expenditures for 2005 are planned to be in the range of $26 million to $33 million and target the Company's Maverick Basin core properties. The primary component of these expenditures is $24.9 million for drilling wells. Almost $1.5 million is earmarked for seismic and leasehold enhancements and other infrastructure expansion activities. The Company's budgeted capital expenditures are intended to be flexible. The budget may expand or contract based on drilling results, operational developments, unanticipated transaction opportunities, market conditions, commodity price fluctuations and working capital availability.

The Company plans to drill or re-enter 63 wells, including 36 Georgetown wells, including 27 gas and nine oil wells, 10 San Miguel waterflood oil wells, three Glen Rose horizontal shoal or reef gas wells, and six Glen Rose porosity zone oil wells. The porosity wells include three new wells and three re-entries. Other companies will operate some of these wells and, therefore, TXCO does not have direct control over when they will be drilled or what final costs will actually be incurred. The following table details typical gross well costs budgeted for 2005 wells:

	Typical Gross Well Costs	
	Dry Hole	**Completed**
Glen Rose oil porosity zone horizontal well	$920,000	$1,100,000
Glen Rose shoal horizontal gas well	750,000	920,000
Glen Rose reef vertical gas well	310,000	550,000
Georgetown horizontal gas well - southern	740,000	1,000,000
Georgetown horizontal oil well - northern	440,000	560,000
San Miguel waterflood oil well	150,000	285,000

Williston Basin Activity: The Company plans to maintain its existing producing properties and the payment of delay rentals and lease extensions on selected undeveloped leases, with scheduled 2005 delay rentals of $176,700. TXCO will continue in its efforts to offer remaining acreage, seismic data, and identified prospects to other industry operators. TXCO participated in the drilling or re-entry of three wells in the Williston Basin during 2004 and anticipates additional activity during 2005.

Sources and Uses of Cash for the Year Ended December 31, 2004

Net cash provided by operating activities was $16.4 million for 2004, up 8.5% from $15.2 million for 2003. Total cash available from all sources, listed in the following table, provided $44.7 million for use in the ongoing expansion, development and exploration of the Company's oil and gas properties. This represents a 1.9% increase over the $43.9 million total cash available for 2003. Included in cash from other sources for 2004 were funds raised from private placements of common stock, as well as proceeds from the exercise of warrants and options to purchase common stock. Proceeds were used to expand the Company's capital expenditure program, enhance balance sheet liquidity, complement on-going operations and provide for general corporate purposes. Pursuant to the private placement agreement, the Company filed a Form S-3 Registration Statement dated June 18, 2004, covering the issued shares on behalf of the investors.

2004 Cash Available to the Company

Beginning cash reserves, January 1, 2004		$ 6,180,560
Net cash provided by operating activities		16,447,259
Internally generated funds		22,627,819
Issuance of common stock, net of expenses	$ 18,620,425	
Borrowings on the Credit Facility, net	3,099,237	
Proceeds from installment obligations	376,894	
Total other sources of cash		22,096,556
2004 Cash Available		$ 44,724,375

The Company applied $39.7 million to fund the expansion and ongoing development of its oil and gas properties, a $3.2 million or 8.9% increase from 2003. Included were drilling, completions, seismic and leasehold acquisition costs primarily targeting TXCO's core area, the Maverick Basin. This represented expenditures for the drilling, completion and re-entry of 69 oil and gas wells and new Maverick Basin mineral lease and seismic option purchases totaling approximately 74,000 acres; as well as acquisition and lease of 7.8 miles of natural gas pipeline. Also included were expenditures for 3-D seismic on an additional 44 square miles of our Maverick basin lease block and other equipment used in the field.

2004 Uses of Cash

Drilling and completion costs, 3-D seismic, and leasehold acquisitions	$ 39,335,091
Other property and equipment	224,092
Net distributions to minority interests	158,552
Sub-total	39,717,735
Debt principal payments	1,888,312
2004 Cash Utilized	$ 41,606,047

The Company made timely payments of $1.9 million on its long-term debt obligations during 2004, excluding $16.0 million paid on its original credit facility and later re-borrowed on its new Facility, while payments of interest totaled $3.0 million.

As a result of these activities, the Company ended 2004 with a current ratio of 0.70 to 1 and a negative working capital of $5.5 million, compared with 0.83 to 1 and negative $2.3 million, respectively, at December 31, 2003.

2004 Acquisitions: TXCO acquired interests in several properties during 2004 in exchange for cash and/or shares of common stock. The Hollimon lease acquisition signed in March, and later amended, gives the Company a 75% interest in 12,200 acres and included a 3-D seismic survey of the area. In June, TXCO acquired a 75% WI in existing seismic option agreements on approximately 62, 000 gross acres adjacent to our Burr and Wipff leases. In October, the Company entered into agreements to purchase a 6.1-mile portion of an existing, privately owned pipeline to serve the northwest portion of TXCO's lease block and, in a related transaction, signed a five-year lease on an additional 1.7-mile segment of existing pipeline.

Sources and Uses of Cash for the Year Ended December 31, 2003

Net cash provided by operating activities was $15.2 million for 2003, up 105% or $7.8 million, from $7.4 million for 2002. Total cash available from all sources, listed in the following table, provided $43.9 million for use in the ongoing expansion, development and exploration of the Company's oil and gas properties. This represents a 40% increase over the $31.3 million total cash available for 2002. Included in cash from other sources for 2003 were funds raised from a private placement of mandatorily redeemable preferred stock and common stock, see Note E to the Audited Consolidated Financial Statements, which were used to fund the expanded drilling program for 2003 and paydown the credit facility.

2003 Cash Available to the Company

Beginning cash reserves, January 1, 2003		$ 2,333,688
Net cash provided by operating activities		15,157,692
Internally generated funds		17,491,380
Private placement of 2,133,333 shares of common stock and 16,000 shares of redeemable preferred stock, net of expenses	$15,010,781	
Borrowings on the Credit Facility	8,200,000	
Borrowings on installment obligations	2,990,530	
Net distributions to minority interests	185,886	
Total other sources of cash		26,387,197
2003 Cash Available		$ 43,878,577

The Company applied $36.5 million to fund the expansion and ongoing development of its oil and gas properties, a $9 million or 33% increase from 2002. Included were drilling, completions, seismic and leasehold acquisition costs primarily targeting TXCO's core area, the Maverick Basin. This represented expenditures for the drilling, completion and re-entry of 80 oil and gas wells and new Maverick Basin mineral lease purchases of approximately 71,000 acres. Also included were expenditures for the 3-D seismic on 37 square miles of our Burr lease block and other equipment used in the field.

2003 Uses of Cash

Drilling and completion costs, 3-D seismic, and leasehold acquisitions	$ 36,071,216
Other property and equipment	396,925
Sub-total	36,468,141
Debt principal payments	1,229,876
2003 Cash Utilized	$ 37,698,017

The Company made timely payments of $1.2 million on its long-term debt obligations during 2003, excluding $5.0 million paid and later re-borrowed on its Credit Facility, while payments of interest totaled $1.2 million.

As a result of these activities, the Company ended 2003 with a current ratio of 0.83 to 1 and a negative working capital of $2.3 million, compared with 0.81 to 1 and negative $1.9 million, respectively, at December 31, 2002.

Burr Ranch Acquisition: In January 2003, the Company acquired the 70,700-acre Burr Ranch lease. The acreage is contiguous to its existing acreage block and the Company believes it has excellent potential to establish production from the Glen Rose, Georgetown and Jurassic intervals. The Company entered into an unsecured installment obligation with the mineral owner in connection with this acquisition. Imputed interest due on the obligation is 4.25% per annum. Subsequent to year-end 2003, installments of $1.4 million were made in January of 2004 and 2005.

Sources and Uses of Cash for the Year Ended December 31, 2002

During 2002, cash from all sources, listed below, resulted in total cash of $31.3 million available for use in meeting the Company's ongoing operational and development needs. Included in the cash received from other sources, are funds raised from a private placement of 2,499,667 shares of restricted common stock to a group of 10 institutional investors. The amount raised was used for acquisitions, to accelerate the development of the Company's extensive Maverick Basin acreage holdings and for general corporate purposes. Pursuant to the placement agreement, the Company filed a Form S-3 Registration Statement dated June 6, 2002, covering the issued shares on behalf of the investors.

2002 Cash Available to the Company

Beginning cash reserves, January 1, 2002		$ 2,019,164
Net cash provided by operating activities		7,389,430
Internally generated funds		9,408,594
Private placement of 2,499,667 shares of common stock	$14,051,893	
Borrowings on the Credit Facility	5,800,000	
Other debt obligations	1,639,915	
Exercise of outstanding options for the Company's common stock	172,755	
Proceeds from sale of oil and gas properties	200,000	
Total other sources of cash		21,864,563
2002 Cash Available		$ 31,273,157

The Company applied $27.4 million to fund the expansion and ongoing development of its oil and gas properties, primarily targeting TXCO's core area. This included expenditures for the drilling, completion and re-entry of 41 oil and gas wells and the acquisition of Maverick Basin mineral leases, and the acquisition of a 69-mile pipeline system. The pipeline system gathers most of the Company's natural gas in the Maverick Basin. The following table summarizes uses of cash during 2002.

2002 Uses of Cash

Drilling and completion costs, 3-D seismic, and leasehold acquisitions	$ 17,410,942
Natural gas gathering system and facilities	5,767,291
Pena Creek acquisition and improvements	3,681,902
Well service equipment	183,145
Upgrade information system and related infrastructure	337,967
Other	39,036
Sub-total	27,420,283
Net distributions to minority interests	434,325
Debt principal payments	1,084,861
2002 Cash Utilized	$ 28,939,469

The Company made timely payments of $1,084,861 on its long-term debt obligations during 2002, while payments on interest totaled $273,213.

Pipeline Acquisitions: In May 2002, the Company completed the acquisition of The Maverick Pipeline System from Aquila Southwest Pipeline Corporation for a total purchase price of $4.9 million. TXCO's initial 80% interest ($3.9 million) was purchased through its newly formed Maverick-Dimmit Pipeline, Ltd. partnership (the "Partnership"). The remaining 20% of the Partnership was held by an unaffiliated private energy concern. This acquisition was funded with proceeds from a $15 million private placement also closed in May.

In June 2002, the Partnership acquired an additional 10 miles of pipeline from TXCO's 62.5%-owned subsidiary, the Paloma Pipeline L.P., for $1 million. The Partnership constructed a 3-mile, $300,000 pipeline extension to connect the Company's growing Chittim lease production to the pipeline system. This extension was placed in service early in the fourth quarter.

During the fourth quarter 2002, TXCO consolidated its position by acquiring the outstanding 20% minority interest in Maverick-Dimmit Pipeline, Ltd., at its book value of $1.3 million. The consolidation was funded through TXCO's available Credit Facility.

Pena Creek Acquisition: Also in May 2002, the Company acquired the Pena Creek oil field in Dimmit County, Texas, from Merit Energy Company for $3.75 million. The purchase was effective April 1, 2002. The acquisition consisted of 94 producing oil wells, 94 injection wells and 28 shut-in wells.

As a result of these activities, the Company ended 2002 with a negative working capital of $1,884,507 and a current ratio of .81 to 1. This year-end position compares to negative working capital of $1,554,454 and a current ratio of .73 to 1 at December 31, 2001. The Company ended 2002 with an unused borrowing base of $6.2 million.

RESULTS OF OPERATIONS

The following table highlights the percentage change from the preceding year for selected items that are significant in our industry. For full information see the Consolidated Statements of Operations and the Sales Volumes discussion.

Change in Selected Income Statement Items:	**2004 vs. 2003**	**2003 vs. 2002**	**2002 vs. 2001**
Operating revenues	+ 46.0%	+ 108.6%	+ 37.8%
Gas gathering revenues	+ 81.8	+ 483.2	+ 100.0
Gas gathering expenses	+ 67.1	+ 476.6	+ 100.0
Lease operations expense	+ 23.9	+ 8.0	+ 69.6
Impairment & abandonments	- 6.7	+ 102.4	- 53.0
Depreciation, depletion & amortization	+ 14.2	+ 32.7	+ 103.0
Net income (loss)	+ 6,742.1	+ 113.1	- 518.4
Basic income (loss) per common share	+ 100.0	+ 112.5	- 433.3

Change in Selected Operating Items:	**2004 vs. 2003**	**2003 vs. 2002**	**2002 vs. 2001**
Oil sales volumes (Bbl)	- 29.2	+ 44.4	+ 528.0
Gas sales volumes (Mcf)	+ 41.1	- 15.2	- 7.0
Combined sales volumes (Mcfe)	+ 1.5	+ 10.5	+ 47.1
Net residue and NGL sales volumes (MMbtu)	+ 38.8	+ 21.4	+ 100.0
Oil average sales price per Bbl	+ 36.8	+ 15.2	+ 4.3
Gas average sales price per Mcf	+ 8.9	+ 63.5	- 26.5
Residue & NGL sales price per MMbtu	+ 33.5	+ 36.1	n/a

The following table provides further detail on the growth of the Company's gas gathering operations:

Gas Gathering Results: ***($ in thousands)***	**2004**	**2003**	**2002**
Revenues:			
Residue gas sales	$20,967	$11,801	$1,860
Natural gas liquids sales	6,205	2,908	553
Transportation and other revenue	364	436	184
Total gas gathering revenues	27,536	15,145	2,597
Expense:			
Third-party gas purchases	23,937	14,019	2,110
Transportation and marketing expenses	498	369	86
Direct operating costs	857	748	429
Total gas gathering operations expense	25,292	15,136	2,625
Gross margin	$ 2,244	$ 9	$ (28)

2004 Compared to 2003

The Company reported a net income of $2.8 million, $0.11 per basic share and $0.10 per diluted share, for the year ended December 31, 2004, compared to a net income of $40,877 or $0.00 per basic and diluted share for the prior year.

Total revenues for 2004 increased by $18.2 million compared to 2003. Natural gas sales volumes increased by 866.6 MMcf while oil sales volumes declined by 132,675 BO as compared with the prior year. Gas gathering revenues increased by $12.4 million over 2003 levels.

The increase in natural gas sales volumes was primarily due to Pena Creek, Georgetown and Chittim Glen Rose horizontal wells placed on production in 2004. The decline in 2004 oil sales volumes compared to the prior year reflects the delay in drilling in the Glen Rose porosity play due to a partner's restructuring. On an equivalent-unit basis, prices averaged 22.0% higher in 2004 as compared to 2003. Crude oil prices averaged 36.8% higher while natural gas prices were up 8.9%. Average higher prices for 2004, as compared to 2003, had a $4.8 million positive impact on revenues in 2004. Commodity prices have been, and continue to be, volatile. During 2004, realized gas prices ranged from a high of $8.05 per Mcf in November to a low of $4.52 per Mcf in September, while realized crude oil prices ranged from a high of $49.49 in October to a low of $31.06 in February. During 2003, realized natural gas prices ranged from a high of $7.26 per Mcf in March to a low of $4.85 per Mcf in November, with realized crude oil prices ranging from a high of $34.32 in February to a low of $25.63 in May. Average daily net gas sales rates in 2004 increased to 8.1 MMcf, a 40.7% increase from the prior year, as production from new wells greatly exceeded the normal decline in aging gas well production. Average daily net oil production rates in 2004 decreased to 878 Bbls, a 29.4% decline from the prior year, primarily as a result of the delay in drilling mentioned above.

Lease operating expense for 2004 increased $1.1 million, from $4.4 million in 2003 to $5.5 million in 2004, a 23.9% increase. This increase is primarily due to the addition of 27 new oil wells and 25 new natural gas wells during 2004. The increase reflects the incremental direct costs of operating the new wells, including the usual costs such as pumper, electricity, water disposal, and other direct overhead charges. Operating expense per Mcfe increased $0.22 from $1.22 in 2003 to $1.44 in 2004. Typically, waterfloods incur higher costs of operations. Excluding the Pena Creek field, operating expense per Mcfe for 2004 is $1.22, an increase of $0.11 from the prior year. Also, included in operating costs is the cost of operating the CBM wells. These costs totaled $478,000 in 2004 and $455,400 in 2003. The CBM wells are in the dewatering phase and therefore have little production relative to their operating costs. Operating cost per Mcfe excluding the CBM wells and Pena Creek averaged $1.12 in 2004 and $1.01 in 2003.

Pursuant to the successful efforts method of accounting for mineral properties, the Company periodically assesses its producing and non-producing properties for impairment. Impairment and abandonments decreased by 6.7% primarily due to lower impairment rates. Depreciation, depletion and amortization increased by $1.2 million, or 14.2%, over 2003 due primarily to the increased number of producing wells being depleted for wells added through the drill bit. The increase in depreciation was due to increased investments in other equipment including computer, pipeline and well service equipment additions. The increase in amortization was primarily due to the acquisition of 3-D seismic and additional loan fees.

Gas gathering operations revenues increased 81.8% in 2004 as compared to 2003. Related operating expenses increased 67.1% from in 2003. These increases are consistent with the increased number of gas wells connected to the gathering system compared to the prior period, as well as higher average sales prices.

While general and administrative costs increased 30.6% when compared to 2003 levels, they represented only 8.4% of revenues. This compares favorably to 2003 when general and administrative expenses were 9.4% of revenues. The higher level of absolute dollar costs reflects the higher sustained level of Company operations and is attributable to higher salaries, benefits, and office-related expenses associated with a full year of costs related to the 10 employees hired across the organization during 2003, along with a partial year for the three new employees hired during 2004, as well as a $237,000 non-cash compensation charge relating to one-year extensions of the expiration date for a non-qualified option and warrant. Also contributing to the increase were higher costs for public company and investor relations related expenses, and professional services. Increases in 2004 general and administrative costs are consistent with the expanded compliance burden mandated by the adoption of the Sarbanes-Oxley Act in mid-2002, see "Sarbanes-Oxley Section 404 Implementation" for additional discussion. These particular costs are likely to continue to increase as the compliance burden expands.

The 19.3% increase in interest income reflects slightly higher average cash levels in interest-bearing accounts. Interest expense increased by $1.6 million in 2004 from 2003 due to higher average debt levels, reflecting a full year of interest on the redeemable preferred stock issued in August 2003 and slightly higher average interest rates on the Credit Facility. A portion of the interest expense is a non-cash accrual reflecting the accretion of the liability on the preferred stock to its full redemption value, which is classified as a long-term liability on the balance sheet. The derivative fair value loss of $19,000 represents the net of the unrealized fair value gain at December 31, 2004 of $134,000 and the $153,000 in cash settlements for closed periods.

2003 Compared to 2002

The Company reported a net income of $40,877 or $0.00 per basic and diluted share for the year ended December 31, 2003, compared to a net loss of $310,970 or $0.02 per basic and diluted share for the prior year.

Revenues for 2003 increased by $20.6 million compared to 2002. Production increased 10.5% on a Bcfe basis, from 4.4 Bcfe in 2002 to 4.8 Bcfe in 2003. Oil production increased by 139.6 MBbl while natural gas production declined by 378.7 MMcf as compared with the prior year. The increase in oil production was due to the new Glen Rose oil wells drilled during 2003, as well as a full year of production from the Pena Creek field acquired in May 2002. The decline in 2003 gas production compared to the prior year reflects the general production decline of the Company's existing mix of maturing gas wells. This decline was partially offset by gas production from the 21 new gas wells drilled and completed during the year. Three new gas wells came on production in the fourth quarter. On an equivalent unit basis, prices averaged 37.5% higher in 2003 as compared to 2002. Crude oil prices averaged 15.2% higher while natural gas prices rose 63.5%. Average higher prices for 2003, as compared to 2002, had a $6.2 million positive impact on revenues in 2003. Commodity prices continue to be volatile. During 2002, realized gas prices ranged from a high of $4.71 per Mcf in November to a low of $1.75 per Mcf in February. During 2003 realized natural gas prices ranged from a high of $7.26 per Mcf in March to a low of $4.85 per Mcf in November.

Average daily net gas production rates in 2003 decreased to 5.8 MMcf, a 15.2% decline from the prior year, while average daily net oil production rates in 2003 increased to 1,244 Bbls, up 44.4% over the prior year.

Lease operating expense ("LOE") for 2003 increased $327,000, from $4.1 million in 2002 to $4.4 million in 2003, an 8.0% increase. This increase was primarily due to the addition of 21 new natural gas wells and 37 new oil wells during 2003 and a full year of operations on the 188 active Pena Creek wells acquired in mid-2002. The increase reflects the incremental direct costs of operating the new wells, including typical costs such as pumper, electricity, water disposal, and other direct overhead charges, as added during 2003 to the Company's existing lease operating expense levels. Operating expense, which adds production taxes to LOE, per Mcfe increased $0.09 from $1.16 in 2002 to $1.25 in 2003. The increase in the rate reflects a full year of Pena Creek field operations, which consists of three waterflood units. Typically, waterfloods incur higher costs of operations. Excluding the Pena Creek field, operating expense per Mcfe for 2003 is $1.11. Also, included in operating costs is the cost of operating the CBM wells. These costs totaled $455,400 in 2003 and $584,000 in 2002. The CBM wells are in the dewatering phase and therefore have little production relative to their operating costs. Operating cost per Mcfe excluding the CBM wells and Pena Creek averaged $1.01 in 2003 and $0.91 in 2002.

Impairment and abandonments increased by 102.4% over 2002 primarily due to higher impairment on producing properties, as production from new plays, such as the Glen Rose oil porosity, did not establish the production rates that were expected. Depreciation, depletion and amortization increased by over $2.1 million, or 32.7%, over 2002 due primarily to the increased number of producing wells being depleted, for wells added through the drill bit and a full year activity for the Pena Creek wells acquired in May 2002. Also contributing to the increase in depreciation was the first full year of depreciation on the pipeline and well service equipment acquired in mid-2002.

Data for 2003 reflects the first full year of operations for the Company's gas gathering system that was acquired in May 2002. Therefore, comparisons of 2003 to 2002 are not meaningful.

While general and administrative costs increased 83.5% when compared to 2002 levels, they were 9.4% of revenues. This compares favorably to 2002 when general and administrative expenses were 10.7% of revenues. The higher level of absolute dollar costs reflects the higher sustained level of Company operations, and is primarily attributable to higher salaries, wages and benefits and office-related expenses associated with 10 new full-time employees across the organization during 2003, as well as increased directors' fees. Also contributing to the increase were higher costs for property and liability insurance. In addition, increases in 2003 general and administrative costs are consistent with the expanded compliance burden mandated by the adoption of the Sarbanes-Oxley Act in mid-2002.

The 42.9% decrease in interest income reflects the low average cash levels in interest-bearing accounts. Interest expense increased by $1.1 million in 2003 from 2002 due to higher debt levels, reflecting the redeemable preferred stock issuance in August of 2003, and higher average balances on the Credit Facility. A portion of the interest expense is an accrual reflecting the accretion of the liability on the preferred stock to its full redemption value, which is classified as a long-term liability on the balance sheet.

CONTRACTUAL OBLIGATIONS AND CONTINGENT LIABILITIES AND COMMITMENTS

The following is a summary of the Company's future payments on obligations as of December 31, 2004.

	Payments Due by Period				
Contractual Obligations	**1 Year**	**2-3 Years**	**4-5 Years**	**After 5 Years**	**Total**
Long-term debt	$ 1,666,466	$ 17,099,237	$ -	$ -	$ 18,765,703
Redeemable preferred stock	-	-	16,000,000	-	16,000,000
Operating lease obligations	390,000	515,000	25,000	-	930,000
Total Contractual Cash Obligations	$ 2,056,466	$ 17,614,237	$ 16,025,000	$ -	$ 35,695,703

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The discussion and analysis of the Company's financial condition and results of operations is based upon the consolidated financial statements, which have been prepared in accordance with U.S. generally accepted accounting principles ("GAAP"). The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. Our significant accounting policies are described in Note A to the Audited Consolidated Financial Statements. Certain of these policies are of particular importance to the portrayal of our financial position and results of operations, and require the application of significant judgment by management. We analyze our estimates, including those related to reserves, depletion and impairment of oil and gas properties, and the ultimate utilization of the deferred tax asset, and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of the Company's financial statements:

Successful Efforts Method of Accounting

The Company accounts for its natural gas and crude oil exploration and development activities utilizing the successful efforts method of accounting. Under this method, costs of productive exploratory wells, development dry holes and productive wells, costs to acquire mineral interests and 3-D seismic costs are capitalized. Exploration costs, including personnel costs, certain geological and geophysical expenses including 2-D seismic costs and delay rentals for oil and gas leases, are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense, net of salvage value, if and when the well is determined not to have found reserves in commercial quantities.

When an entire interest in an unproved property is sold, a gain or loss is recognized for the difference between the carrying value of the property and the sales price. If a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained. On the sale of an entire or partial interest in a proved property, the asset is relieved along with the corresponding accumulated depreciation, depletion, and amortization. When compared with the sales price a resulting gain or loss is recognized in income.

The application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as developmental or exploratory which will ultimately determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Wells may be completed that are assumed to be productive and ultimately deliver oil and gas in quantities insufficient to be economic, which may result in the abandonment or recompletion of the wells at later dates. Wells are drilled that have targeted geologic structures that are both developmental and exploratory in nature and an allocation of costs is required to properly account for the results. The evaluation of oil and gas leasehold acquisition costs requires managerial judgment to estimate the fair value of these costs with reference to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.

The successful efforts method of accounting can have a significant impact on the operational results reported when the Company is entering a new exploratory area in hopes of finding an oil and gas field that will be the focus of future development drilling activity. The initial exploratory wells may be unsuccessful and will be expensed.

Reserve Estimates

The Company's estimates of oil and gas reserves, by necessity, are projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable oil and gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effects of regulations by governmental agencies and assumptions governing future oil and gas prices, future operating costs, severance taxes, development costs and workover gas costs, all of which may in fact vary considerably from actual results. The future drilling costs associated with reserves assigned to proved undeveloped locations may ultimately increase to an extent that these reserves may be later determined to be uneconomic. For these reasons, estimates of the economically recoverable quantities of oil and gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows expected therefrom may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of the Company's oil and gas properties and/or the rate of depletion of the oil and gas properties. Actual production, revenues and expenditures, with respect to the Company's reserves, will likely vary from estimates and such variances may be material. TXCO contracts with an independent engineering firm to provide reserve estimates for reporting purposes.

Impairment of Oil and Gas Properties

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

Given the complexities associated with oil and gas reserve estimates and the history of price volatility in the oil and gas markets, events may arise that would require the Company to record an impairment of the recorded book values associated with oil and gas properties. The Company has recognized impairments in both the current and prior years and there can be no assurance that impairments will not be required in the future.

Income Taxes

The Company is subject to income and other similar taxes on its operations. When recording income tax expense or benefit, certain estimates are required because: (a) income tax returns are generally filed many months after the close of the calendar year; (b) tax returns are subject to audit which can take years to complete; and (c) future events often impact the timing of when income tax expenses or benefits are recognized. The Company has deferred tax assets relating to tax net operating loss carryforwards and other deductible differences. The Company routinely evaluates all deferred tax assets to determine the likelihood of realization. A valuation allowance is recognized on deferred tax assets when management believes that certain of these assets are not likely to be realized, or if likely realization may be many years in the future.

The Company's deferred tax assets exceeded its liabilities at December 31, 2004, and 2003. Based on the Company's projected profitability, a valuation allowance was recorded of approximately $1.6 million at December 31, 2004 and $3.0 million at December 31, 2003, resulting in a net deferred tax asset at each respective year-end of $5.2 million. Although the Company believes the valuation allowance and resulting deferred tax asset is reasonable, the ultimate recoverability or utilization of the asset is subject to change in future years for reasons explained above.

NEW ACCOUNTING STANDARDS

In May 2003, the Financial Accounting Standards Board ("FASB") issued Statement of Accounting Standards No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity" ("SFAS No. 150"). This statement requires that an issuer classify a financial instrument that is within its scope as a liability because the financial instrument embodies an obligation of the issuer. SFAS No. 150 is effective for all financial instruments entered into or modified after May 31, 2003, and requires reclassification of existing financial instruments in financial statements for the first interim period beginning after June 15, 2003. The mandatorily redeemable preferred stock discussed in Note E to the Audited Consolidated Financial Statements is recorded as a liability as a result of this Statement.

On January 1, 2004, the Company adopted FASB Interpretation No. 46R, "Consolidation of Variable Interest Entities" (FIN 46R). This interpretation addresses consolidation of business enterprises of variable interest. The adoption of FIN 46R did not have a material impact on the Company's financial position or results of operations.

In December 2004, the FASB issued Statement 123R, "Share-Based Payment," which requires all companies to measure compensation cost for all share-based payments (including employee stock options) at fair value, effective for public companies for interim or annual periods beginning after June 15, 2005. The expected impact to the Company for options and warrants currently granted is expected to be approximately $123,000 in the second half of 2005, and $180,000 during 2006.

The FASB has released for comment proposed Staff Position FAS 19-a "Accounting for Suspended Well Costs." FAS 19-a would amend FASB Statement No. 19 "Financial Accounting and Reporting by Oil and Gas Producing Companies" and provides guidance for evaluating whether adequate progress on assessing reserves has been demonstrated to allow for the continued capitalization of certain in-progress exploratory wells for companies who use the successful efforts method of accounting. The SEC issued a letter to the industry requiring additional disclosures in this Annual Report on Form 10-K prior to finalization of FAS 19-a. This additional disclosure has been included in Note L to the Audited Consolidated Financial Statements. The adoption of FAS 19-a is not expected to have a material impact on the Company's financial position or results of operations.

Sarbanes-Oxley Section 404 Implementation

Presented in Item 9A of this annual report is the first "Management Report On Internal Control Over Financial Reporting." This new report is required under Section 404 of the Sarbanes-Oxley Act of 2002. In anticipation of the extensive work involved with complying with these requirements for the first time, TXCO's Board of Directors authorized management to enlist the assistance of an outside consulting firm. In January of 2004, after interviewing several firms, management and the Board selected Grant Thornton LLP to assist with the project. Grant Thornton assisted management with the review and update of existing documentation of internal controls, and facilitated the necessary steps to complete the evaluation of the adequacy and effectiveness of these controls. Management and the Board have a long-standing commitment to excellence in compliance and controls. This created an environment that fostered good control practices. A number of improvements to process flow were made during the project, primarily related to systems.

Total expenditures through February of 2005 for this project are estimated at $335,000, of which $198,000 was included in general and administrative expenses during 2004. The remainder will be expensed during the first half of 2005.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

***Commodity Risk*:** The Company's major market risk exposure is the commodity pricing applicable to its oil and natural gas production. Realized commodity prices received for such production are primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to natural gas. Prices have fluctuated significantly over the last five years and such volatility is expected to continue, and the range of such price movement is not predictable with any degree of certainty. During 2003, the Company was party to a forward sale of approximately 2,700 MMbtu per day of its natural gas production from February 1, 2003, through December 31, 2003, at a fixed price of $4.45 per MMbtu. This represented approximately 30% of the Company's daily net natural gas sales as of year-end 2002. No such forward sale agreement was in place for 2004. However, the Company had in place ratio swap agreements that hedge approximately 40% of its monthly production as of the inception of the hedge on October 1, 2004. These swap agreements expire in October 2005. In early March 2005, the Company entered into additional financial price hedges, extending coverage for the same monthly volumes through October of 2006. These new hedges are in the form of fixed price swaps with prices of $49.40 per BO and $6.83 per MMBtu on a basis adjusted to Houston Ship Channel prices. A 10% fluctuation in the price received for oil and gas production would have an approximate $3.0 million impact on the Company's annual revenues based on 2004 sales volumes.

The Consolidated Balance Sheet at December 31, 2004, includes a receivable for derivative fair value gain of $134,000 in the Prepaid Expenses and Other line item. A derivative fair value loss of $19,000 was recognized on the Consolidated Statement of Operations in 2004. This loss is the net of the unrealized fair value gain of $134,000 and the cash settlement losses of $153,000 for closed months. At the end of February 2005, the valuation had swung in favor of the counter-party and the Company has an unrealized liability of approximately $700,000 related to these hedges. If product prices remain at the current levels, TXCO may record a Loss on Derivative Fair Value Adjustment of approximately $800,000 during the first quarter of 2005.

Interest Rate Risk**:** The Company has borrowed funds under its Revolving Credit Facility with Guaranty Bank, with interest based on LIBOR rates plus an applicable margin. At March 4, 2005, the Company had $20.4 million in total borrowings under the Facility, with an average interest rate of 5.1%, and $100,000 at a floating rate based on the prevailing prime rate. An annualized 10% fluctuation in interest charged on the floating rate balance at March 4, 2005, would have an approximate $100,000 impact on the Company's annual net income.

Financial Instruments**:** The Company's financial instruments consist of cash equivalents and accounts receivable. Its cash equivalents are cash investment funds that are placed with a major financial institution. Substantially all of the Company's accounts receivable result from oil and gas sales or joint interest billings to third parties in the oil and natural gas industry. This concentration of customers and joint interest owners may impact the Company's overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. Historically, the Company has not experienced any significant credit losses on such receivables. See Certain Business Risks section.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The Consolidated Financial Statements and Notes thereto are set out in this Form 10-K commencing on page F-1.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

ITEM 9A. CONTROLS AND PROCEDURES

A review and evaluation was performed by the Company's management, including the Company's Chief Executive Officer (the "CEO") and Chief Financial Officer (the "CFO"), of the effectiveness of the design and operation of the Company's disclosure controls and procedures as of the end of the period covered by this annual report on Form 10-K. Based on that review and evaluation, the CEO and CFO have concluded that the Company's current disclosure controls and procedures, as designed and implemented, were effective. There have been no changes in the Company's internal controls or in other factors that have significantly affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting subsequent to the date of their evaluation. There were no material weaknesses identified in the course of such review and evaluation and, therefore, no corrective measures were required.

On February 1, 2005, in connection with product (oil) storage and sales operations, management instituted additional controls such as sealing all of the product tanks and requiring company personnel to be present at the time oil is to be removed by product haulers for ultimate sale. These additional controls, while outside standard field procedures within the industry, were instituted because the Company recently identified a discrepancy between field production volumes and sales volumes of oil from a selected set of tank batteries. Our investigation of this matter continues but it currently appears that the discrepancy represents less than one percent of the total 2004 production expressed in Mcfe. Accordingly, we do not believe that it rises to the level of a material weakness or a significant deficiency. However, management advised our independent registered public accounting firm, Audit Committee, and Board of Directors of the discrepancy. As of the date of this report the new procedures appear to be working. We will continue to monitor this area closely throughout the year. Management believes that this discrepancy did not affect the accuracy of the Company's financial statements included in this report. In addition, the Company is continuing to enforce existing policies and improving processes where applicable.

Management Report On Internal Control Over Financial Reporting

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is defined in Rules 13a-15(f) and 15d-15(f) promulgated under the Exchange Act as a process designed by, or under the supervision of, the Company's principal executive and principal financial officers and effected by the Company's Board, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP and includes those policies and procedures that:

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risks that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2004. In making this assessment, the Company's management used criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control-Integrated Framework.

Based on its assessment, the Company's management believes that, as of December 31, 2004, the Company's internal control over financial reporting was effective based on those criteria.

The Company's independent auditors, Akin, Doherty, Klein & Feuge, P.C., have issued an audit report on management's assessment of the Company's internal control over financial reporting. Their report is presented on the next page.

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
ON INTERNAL CONTROL OVER FINANCIAL REPORTING**

To The Board of Directors And Stockholders of
The Exploration Company of Delaware, Inc. and Subsidiaries
San Antonio, Texas

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that The Exploration Company of Delaware, Inc. (the Company) maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in "Internal Control--Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that The Exploration Company of Delaware, Inc. maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, The Exploration Company of Delaware, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets as of December 31, 2004 and 2003 and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2004, of The Exploration Company of Delaware, Inc. and our report dated March 15, 2005, expressed an unqualified opinion thereon.

/s/ Akin, Doherty, Klein & Feuge, P.C.

San Antonio, Texas
March 15, 2005

ITEM 9B. OTHER INFORMATION

None

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information required by this Item relating to our directors and nominees, executive officers and compliance with Section 16(a) of the Exchange Act is included under the captions "Proposal I -- Election of Directors," "Executive Officers" and "Compliance with Section 16(a) of the Securities Exchange Act" in our Proxy Statement related to the 2005 Annual Meeting of Shareholders and is incorporated herein by reference. The Proxy Statement will be filed with the Securities and Exchange Commission pursuant to Regulation 14A of the Exchange Act of 1934, as amended, not later than 120 days after December 31, 2004.

In January 2004, the Company amended its "Code of Conduct for All Employees and Directors." This document was filed with the SEC as Exhibit 14 with its Form 10-Q for the period ended March 31, 2004, and is also available on the Company's web site, www.txco.com, under the Governance tab.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this section will be contained in the Proxy Statement under the heading "Executive Compensation" and is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information required by this section will be contained in the Proxy Statement under the heading "Security Ownership of Certain Beneficial Owners and Management" and is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required by this section will be contained in the Proxy Statement under the heading "Certain Relationships and Related Transactions" and is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this section will be contained in the Proxy Statement under the heading "Auditor Independence" and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(A) The following documents are being filed as part of this annual report on Form 10-K after the signature page, commencing on page F-1.

(1) Consolidated Financial Statements:
Report of Independent Registered Public Accounting Firm.
Consolidated Balance Sheets, December 31, 2004 and December 31, 2003.
Consolidated Statements of Operations, Years Ended December 31, 2004, 2003 and 2002.
Consolidated Statements of Stockholders' Equity, Years Ended December 31, 2004, 2003 and 2002.
Consolidated Statements of Cash Flows, Years Ended December 31, 2004, 2003 and 2002.
Notes to Audited Consolidated Financial Statements.

(2) Financial Statement Schedules.
Schedule II - Valuation and Qualifying Reserves.

All other schedules for which provision is made in the applicable accounting regulations of the Securities and Exchange Commission are omitted as the required information is inapplicable or the information is presented in the Consolidated Financial Statements or Notes thereto.

(3) Exhibits:

Exhibit Number	Exhibit Description	Filed Herewith	Form	Exhibit	Filing Date
3.1	Certificate of Incorporation of The Exploration Company of Delaware, Inc.		Def14A	Appendix B	01/12/1999
3.2	Amended and Restated Bylaws of The Exploration Company of Delaware, Inc.		S-8	3.1	05/10/2002
4.1	Registrant's Rights Agreement, which includes: as Exhibit A thereto, the Certificate of Designation of Series A Junior Participating Preferred Stock; as Exhibit B thereto, Form of Right Certificate; as Exhibit C thereto, Summary of Rights to Purchase Preferred Shares.		8-K	4.1	06/29/2000
4.2	Subscription Agreement among The Exploration Company of Delaware, Inc., Kayne Anderson Energy Fund II, L.P. and Gryphon Master Fund, L.P., dated as of August 1, 2003.		8-K	4.1	08/21/2004
4.3	Certificate of Designation of Redeemable Preferred Stock, Series B of The Exploration Company of Delaware, Inc.		8-K	4.2	08/21/2004
4.4	Rights Agreement, between the Registrant and Kayne Anderson Energy Fund II, L.P. and Gryphon Master Fund, L.P.		8-K	4.3	08/21/2004
4.5	Amendment to Subscription Agreement, dated August 5, 2003.		8-K	4.4	08/21/2004
4.6	Credit Agreement between the Registrant and Guaranty Bank, GSB, dated June 30, 2004.		10-Q	4	08/09/2004
4.7	Credit Agreement between The Exploration Company and Guaranty Bank, FSB, dated June 30, 2004.		10-Q	4	08/09/2004
10.1*	Employment Agreement between the Registrant and James E. Sigmon dated October 1, 1984.		10-K	10.1	11/27/1985
10.2*	1995 Flexible Incentive Plan.		Def14A	A	04/28/1995
10.3*	Amendment to its 1995 Flexible Incentive Plan.		Def14A	Proposal II	02/02/1999
10.4	Loan Agreement dated March 4, 2002, between The Exploration Company and Hibernia National Bank.		10-K	10.12	03/31/2003
10.5	First Amendment to Loan Agreement dated December 13, 2002 between The Exploration Company and Hibernia National Bank.		10-K	10.13	03/31/2003
10.6*	Amendment to the 1995 Flexible Incentive Plan.		Def14A	Proposal IV	04/16/2001
10.7*	Amendment to the 1995 Flexible Incentive Plan.		Def14A	Proposal III	04/25/2003
10.8	Second Amendment to Loan Agreement and Waiver No. 2 dated August 13, 2003 between The Exploration Company and Hibernia National Bank.		10-K	10.19	03/15/2004
10.9	Registrant's Audit Committee Charter, as revised in January 2004, filed as Exhibit 10.21 to registrant's Annual Report on Form 10-K, dated March 15, 2004.		10-K	10.21	03/15/2004

Exhibit Number	Exhibit Description	Filed Herewith	Form	Exhibit	Filing Date
10.10	Third Amendment to Loan Agreement dated December 31, 2003 between The Exploration Company and Hibernia National Bank, filed with the registrant's Annual Report on Form 10-K, dated March 15, 2004.		10-K	10.22	03/15/2004
10.11	Line of Credit Note dated December 31, 2003 between The Exploration Company and Hibernia National Bank.		10-K	10.23	03/15/2004
10.12	Energy Option Transaction Confirmation dated October 5, 2004, between the registrant and Macquarie Bank Limited OBU.		10-Q	10.1	11/09/2004
10.13	Letter of Credit Agreement dated October 7, 2004, between the registrant and Guaranty Bank.		10-Q	10.2	11/09/2004
10.14*	Sample of Amended and Restated Change of Control Letter Agreements issued to all employees during December 2004.		8-K	10.1	12/17/2004
14.1	Code of Ethical Conduct for Senior Officers and Financial Managers.		10-K	14	03/15/2004
14.2	Code of Conduct for All Employees and Directors.		10-Q	14	05/10/2004
23.1	Consent of Akin, Doherty, Klein & Feuge.	X			
23.2	Consent of DeGolyer and MacNaughton	X			
23.3	Consent of Netherland, Sewell & Associates, Inc.	X			
31.1	Certification of Chief Executive Officer required pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934, as amended.	X			
31.2	Certification of Chief Financial Officer required pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934, as amended.	X			
32.1+	Certification of Chief Executive Officer required pursuant to 18 U.S.C. Section 1350 as required by the Sarbanes-Oxley Act of 2002.	X			
32.2+	Certification of Chief Financial Officer required pursuant to 18 U.S.C. Section 1350 as required by the Sarbanes-Oxley Act of 2002.	X			

* Management contract or compensatory plan or arrangement.

\+ This exhibit shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, or otherwise subject to the liability of that section, and shall not be deemed to be incorporated by reference into any filing under the Securities Act of 1933 or the Securities Exchange Act of 1934.

SIGNATURES

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

THE EXPLORATION COMPANY OF DELAWARE, INC.
Registrant

October 10, 2005

By: /s/ James E. Sigmon
James E. Sigmon, President

October 10, 2005

By: /s/ P. Mark Stark
P. Mark Stark, Chief Financial Officer
Vice-President-Finance
(Principal Accounting Officer)

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
The Exploration Company of Delaware, Inc. and Subsidiaries
San Antonio, Texas

We have audited the consolidated balance sheets of The Exploration Company of Delaware, Inc. and Subsidiaries (collectively referred to as "The Exploration Company" or "Company") as of December 31, 2004 and 2003, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the years in the three year period ended December 31, 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of The Exploration Company as of December 31, 2004 and 2003, and the results of its operations and cash flows for each of the years in the three year period ended December 31, 2004, in conformity with U. S. generally accepted accounting principles.

Our audits referred to above included audits of the financial statement schedule listed under Item 15. In our opinion, this financial statement schedule presents fairly, in all material respects, in relation to the financial statements taken as a whole, the information required to be set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of The Exploration Company of Delaware, Inc.'s internal control over financial reporting as of December 31, 2004 based on criteria established in "Internal Control -- Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 15, 2005 expressed an unqualified opinion thereon.

/s/ Akin, Doherty, Klein & Feuge
AKIN, DOHERTY, KLEIN & FEUGE, P.C.
San Antonio, Texas
March 15, 2005

THE EXPLORATION COMPANY
Consolidated Balance Sheets

	December 31	
	2004	**2003**
Assets		
Current Assets		
Cash and equivalents	$3,118,328	$ 6,180,560
Accounts receivable:		
Joint interest owners	1,736,944	564,116
Oil and gas sales	7,248,429	4,273,849
Prepaid expenses and other	934,016	718,853
Total Current Assets	13,037,717	11,737,378
Property and Equipment, net - successful efforts method of accounting for oil and gas properties	94,836,476	66,155,827
Other Assets		
Deferred tax asset	5,232,718	5,232,718
Other assets	1,130,413	1,080,290
Total Other Assets	6,363,131	6,313,008
Total Assets	$114,237,324	$84,206,213

See notes to audited consolidated financial statements.

THE EXPLORATION COMPANY
Consolidated Balance Sheets

	December 31	
	2004	**2003**
Liabilities And Stockholders' Equity		
Current Liabilities		
Accounts payable, trade	$10,389,119	$ 8,186,705
Other payables and accrued liabilities	5,449,553	3,709,016
Undistributed revenue	1,062,000	416,399
Current portion of long-term debt	1,666,466	1,752,286
Total Current Liabilities	18,567,138	14,064,406
Long-Term Liabilities		
Long-term debt, net of current portion	17,099,237	15,425,598
Redeemable preferred stock, Series B (redemption value - $16 million)	10,991,308	10,135,335
Accrued dividends - preferred stock	217,728	57,732
Asset retirement obligation	1,679,600	1,537,600
Total Long-Term Liabilities	29,987,873	27,156,265
Minority Interest in Consolidated Subsidiaries	-	193,441
Stockholders' Equity		
Preferred stock; authorized 10,000,000 shares, issued and outstanding 16,000 shares	-	-
Common stock, par value $0.01 per share; authorized 50,000,000 shares, issued 28,110,363 and 22,242,849 shares, and outstanding 28,010,563 and 22,143,049	281,103	222,428
Additional paid-in capital	84,010,730	63,976,021
Accumulated deficit	(18,363,513)	(21,160,341)
Less treasury stock, at cost, 99,800 shares	(246,007)	(246,007)
Total Stockholders' Equity	65,682,313	42,792,101
Total Liabilities and Stockholders' Equity	$114,237,324	$84,206,213

See notes to audited consolidated financial statements.

THE EXPLORATION COMPANY
Consolidated Statements of Operations

	Years Ended December 31		
	2004	2003	2002
Revenues			
Oil and gas sales	$30,181,581	$24,390,767	$16,049,798
Gas gathering operations	27,535,689	15,145,154	2,596,955
Other operating income	18,062	9,281	311,611
Total Revenues	57,735,332	39,545,202	18,958,364
Costs and Expenses			
Lease operations	5,460,372	4,408,205	4,081,162
Production taxes	1,588,387	1,501,041	973,078
Exploration expenses	2,448,800	2,187,216	1,567,098
Impairment and abandonments	2,354,553	2,522,548	1,246,495
Gas gathering operations	25,291,780	15,136,279	2,625,313
Depreciation, depletion and amortization	9,851,485	8,627,678	6,500,625
General and administrative	4,852,513	3,716,439	2,025,440
Total Costs and Expenses	51,847,890	38,099,406	19,019,211
Income (loss) from operations	5,887,442	1,445,796	(60,847)
Other Income (Expense)			
Interest income	31,771	26,626	46,663
Interest expense	(2,909,550)	(1,365,233)	(273,213)
Loan fee amortization	(82,732)	(17,604)	(14,507)
Derivative fair value loss	(18,623)	-	-
Total Other Expense	(2,979,134)	(1,356,211)	(241,057)
Income (loss) before income taxes, minority interest and cumulative effect of change in accounting principle	2,908,308	89,585	(301,904)
Minority interest in income (loss) of subsidiaries	34,889	75,292	(84,066)
Income (loss) before income taxes and cumulative effect of change in accounting principle	2,943,197	164,877	(385,970)
Income tax (expense) benefit	(146,369)	(50,000)	75,000
Cumulative effect of change in accounting principle, net of tax	-	(74,000)	-
Net Income (Loss)	$2,796,828	$ 40,877	$ (310,970)
Earnings (Loss) Per Share:			
Basic earnings (loss) before cumulative effect of change in accounting principle	$ 0.11	$ 0.01	$ (0.02)
Cumulative effect of change in accounting principle	-	(0.01)	-
Basic Earnings (Loss) Per Share	$ 0.11	$ 0.00	$ (0.02)
Diluted earnings (loss) before cumulative effect of change in accounting principle	$ 0.10	$ 0.01	$ (0.02)
Cumulative effect of change in accounting principle	-	(0.01)	-
Diluted Earnings (Loss) Per Share	$ 0.10	$ 0.00	$ (0.02)
Weighted average number of common shares outstanding:			
Basic	26,066,299	20,781,223	19,080,847
Diluted	26,971,440	21,295,257	19,080,847

See notes to audited consolidated financial statements.

THE EXPLORATION COMPANY
Consolidated Statements of Stockholders' Equity

	Common Stock		Additional Paid-in	Accumulated	Treasury	
	Shares	Amount	Capital	Deficit	Stock	Total
Balance at December 31, 2001	17,496,849	$174,968	$44,017,983	$(20,890,248)	$(246,007)	$23,056,696
Common stock options exercised	113,000	1,130	171,625	-	-	172,755
Issuance of common stock - net of expenses of $946,112	2,499,667	24,997	14,026,896	-	-	14,051,893
Net loss for the year	-	-	-	(310,970)	-	(310,970)
Balance at December 31, 2002	20,109,516	201,095	58,216,504	(21,201,218)	(246,007)	36,970,374
Issuance of common stock - net of expenses of $400,959	2,133,333	21,333	5,741,641	-	-	5,762,974
Other adjustments	-	-	17,876	-	-	17,876
Net income for the year	-	-	-	40,877	-	40,877
Balance at December 31, 2003	22,242,849	222,428	63,976,021	(21,160,341)	(246,007)	42,792,101
Issuance of common stock - net of expenses of $1,237,168	5,867,514	58,675	19,797,376	-	-	19,856,051
Non-cash compensation	-	-	237,333	-	-	237,333
Net income for the year	-	-	-	2,796,828	-	2,796,828
Balance at December 31, 2004	28,110,363	$281,103	$84,010,730	$(18,363,513)	$(246,007)	$65,682,313

See notes to audited consolidated financial statements.

THE EXPLORATION COMPANY
Consolidated Statements of Cash Flows

	Years Ended December 31		
	2004	**2003**	**2002**
Operating Activities			
Net income (loss)	$2,796,828	$ 40,877	$ (310,970)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	9,851,485	8,627,678	6,500,625
Impairments and abandonments	2,354,553	2,522,548	1,246,495
Minority interest in (income) loss of subsidiaries	(34,889)	(75,292)	84,066
Cumulative effect of change in accounting principle	-	74,000	-
Non-cash interest expense and accretion of liability - redeemable preferred stock	1,015,969	677,002	-
Non-cash compensation expense	237,333	-	-
Non-cash hedging fair value gain	(133,972)	-	-
Changes in operating assets and liabilities:			
Receivables	(4,147,408)	280,305	(3,175,627)
Prepaid expenses and other	(81,192)	(215,677)	(229,573)
Accounts payable and accrued expenses	4,588,552	3,226,251	3,274,414
Net cash provided by operating activities	16,447,259	15,157,692	7,389,430
Investing Activities			
Development and purchases of oil and gas properties	(39,335,091)	(36,071,216)	(27,381,247)
Purchase of other equipment	(224,092)	(396,925)	-
Proceeds from sale of oil and gas properties	-	-	200,000
Changes in minority interests	(158,552)	185,886	(434,325)
Other changes	-	-	(39,036)
Net cash used by investing activities	(39,717,735)	(36,282,255)	(27,654,608)
Financing Activities			
Proceeds from issuance of redeemable preferred stock, net of offering costs	-	9,229,931	-
Proceeds from long-term debt obligations	3,476,131	11,190,530	7,439,915
Payments on long-term debt obligations	(1,888,312)	(1,229,876)	(1,084,861)
Proceeds from common stock transactions, net of expenses	18,620,425	5,780,850	14,224,648
Net cash provided by financing activities	20,208,244	24,971,435	20,579,702
Change in Cash and Equivalents	(3,062,232)	3,846,872	314,524
Cash and Equivalents at Beginning of Year	6,180,560	2,333,688	2,019,164
Cash and Equivalents at End of Year	$3,118,328	$ 6,180,560	$ 2,333,688
Supplemental Disclosures:			
Cash paid for interest	$ 3,011,322	$ 1,200,230	$ 273,213
Cash paid for income taxes	-	-	-

See notes to audited consolidated financial statements.

NOTE A - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Operations: The Exploration Company of Delaware, Inc., d.b.a. The Exploration Company ("TXCO" or "Company") is an independent energy company engaged in the acquisition, exploration, development and production of oil and gas properties. The Company's primary focus is on developing oil and gas reserves on properties located in Texas. The Company also owns properties in South Dakota, North Dakota and Montana.

Consolidation: The financial statements include the accounts of the Company and its majority-owned subsidiaries. The subsidiaries own and operate a gas gathering system that is utilized by the Company for delivery of natural gas from its Texas properties, as well as the delivery of natural gas produced by third parties. All significant intercompany balances and transactions have been eliminated in consolidation.

Revenue Recognition: The Company recognizes oil and gas revenue from its interest in producing wells as the oil and gas is sold to third parties. Gas gathering operations revenues are recognized upon delivery of the product to third parties.

Reclassifications: Certain amounts for 2003 and 2002 have been reclassified to conform to the 2004 presentation.

Cash and Equivalents: The Company considers all highly liquid investments with an original maturity of three months or less to be cash and equivalents.

Accounts Receivable: Accounts receivable are reported at outstanding principal net of an allowance for doubtful accounts of approximately $27,000 at December 31, 2004, 2003 and 2002. The Company normally does not charge interest on accounts receivable. The allowance for doubtful accounts is generally determined based on the Company's historical losses, as well as a review of specific accounts. Accounts are charged off when collection efforts have failed and the account is deemed uncollectible.

Oil and Gas Properties: The Company uses the successful efforts method of accounting for its oil and gas activities. Costs to acquire mineral interests, developmental 3-D seismic costs, development wells, and costs to drill and equip exploratory wells that find proved reserves are capitalized. Costs, net of salvage value, for exploratory wells that do not find proved reserves, geological and geophysical costs, 2-D seismic costs, and costs of carrying and retaining unproved properties are expensed as incurred.

Management considers 3-D seismic shoots over the proved area of an oil or gas reservoir as developmental in nature. The Company uses its 3-D seismic database when selecting drilling sites, assessing recompletion opportunities, determining the cause when performance of a producing property is not as expected, as well as qualifying reservoir size and determining probable extensions and/or drainage areas for existing fields. The Company amortizes the cost of its capitalized developmental 3-D seismic shoots over a 60-month period.

Any well not drilled within the proved area of an oil or gas reservoir targeting a known productive depth is considered exploratory. Costs for exploratory wells in-progress are capitalized until a determination is made that no proven reserves are likely to be realized from the well's various potential intervals. If the determination is made that no proven reserves are likely to be realized from a target interval, the costs associated with that target interval are expensed. Costs associated with wells having several potential intervals remain capitalized until the determination of proven reserves is made for the final interval. Costs attributed to lower zones may be written off while upper zones remain in-progress due to planned re-completion efforts.

Depreciation, depletion and amortization ("DD&A") of oil and gas properties is computed using the unit-of-production method based upon recoverable reserves as determined by the Company's independent reservoir engineers. Depletion of coalbed methane properties begins following the dewatering phase of each coalbed methane project. Oil and gas properties are periodically assessed for impairment. If the unamortized capitalized costs of proved properties are in excess of the undiscounted future cash flows before income taxes, the property is impaired. Future cash flows are determined based on management's best estimate and may consider changes in prices for the product as considered most likely to occur in future periods. Unproved properties are also evaluated periodically and, if the unamortized cost is in excess of estimated fair value, impairment is recognized.

NOTE A - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - continued

Other Property and Equipment: Other property and equipment is recorded at cost. Depreciation is computed using the straight-line method over the estimated useful lives of the assets ranging from five to fifteen years. Major renewals and betterments are capitalized while repairs are expensed as incurred.

Federal Income Taxes: The Company follows the liability method of accounting for income taxes under which deferred tax assets and liabilities are recognized for the future tax consequences. Accordingly, deferred tax assets and liabilities are determined based on the temporary differences between the financial statement and tax basis of assets and liabilities, using enacted tax rates in effect for the year in which the differences are expected to reverse.

Earnings (Loss) Per Share: Basic earnings per common share is computed by dividing net income by the weighted average number of common shares outstanding during each year. The diluted earnings per share calculation adds to the weighted average number of common shares outstanding the incremental shares that would have been outstanding assuming the exercise of dilutive stock options.

Financial Instruments: The Company's financial instruments that are exposed to concentrations of credit risk consist primarily of cash equivalents and accounts receivable. The Company places its temporary cash investments with major financial institutions which, from time-to-time, may exceed federally insured limits, and believes the risk of loss is minimal. Substantially all of the Company's accounts receivable result from oil and gas sales or joint interest billings to third parties in the oil and natural gas industry. This concentration of customers and joint interest owners may impact the Company's overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. Historically, the Company has not experienced credit losses on such receivables. Unless otherwise specified, the Company believes the book value of the financial instruments approximates their fair value.

Commodity Hedging Contracts: The Company occasionally enters into derivative contracts, primarily options and swaps, to hedge future natural gas and crude oil production in order to mitigate the risk of market price fluctuations and to comply with covenants under the revolving credit facility. All derivatives are recognized on the balance sheet and measured at fair value (marked to market). The Company considers its hedges on a case by case basis to determine the accounting treatment. To date, the Company has not elected hedge accounting treatment; therefore, changes in the fair value of the derivative are recognized currently in earnings. Gains and losses on hedging instruments and adjustments of the carrying amounts of hedged items are included in the Other Income (Expense) section of the Consolidated Statements of Operations.

Use of Estimates: The preparation of financial statements in conformity with U. S. generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Estimates that may significantly impact the Company's financial statements include reserves, depletion and impairment on oil and gas properties, and the ultimate utilization of the deferred tax asset.

Accounting for Stock Based Compensation: At December 31, 2004, the Company has a stock-based employee compensation plan that is described more fully in the Stockholders' Equity footnote. The Company accounts for this plan under the recognition and measurement principles of APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related Interpretations. No stock-based employee compensation cost related to stock options is normally reflected in net income, as all options granted under the plan had an exercise price equal to, or greater than, the market value of the underlying common stock on the date of grant. However, in 2004, the expiration date of an option and a warrant were extended for one year, resulting in the recognition of $237,333 in non-cash compensation expense. See paragraph 3 of "Recent Accounting Pronouncements" below for disclosure of upcoming changes in accounting for stock compensation.

THE EXPLORATION COMPANY
Notes to Audited Consolidated Financial Statements
Years Ended December 31, 2004, 2003 and 2002

NOTE A - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - continued

The following table illustrates the effect on net income and earnings per share as if the Company had applied the fair value recognition provisions of SFAS No. 123, "Accounting for Stock-Based Compensation," to stock-based employee compensation for the years ended December 31:

	2004	2003	2002
Net income (loss) as reported	$2,796,828	$ 40,877	$(310,970)
Deduct: Total stock-based compensation expense determined under the fair value based method for all awards, net of related tax effects	(284,273)	(764,165)	(303,290)
Pro forma earnings (loss)	$2,512,555	$(723,288)	$(614,260)
Earnings (loss) per common share:			
Basic, as reported	$ 0.11	$ 0.00	$ (0.02)
Basic, pro forma	0.10	(0.03)	(0.03)
Diluted, as reported	0.10	0.00	(0.02)
Diluted, pro forma	0.09	(0.03)	(0.03)

Government Regulations: The Company's oil and gas operations are subject to federal, state and local provisions regulating the discharge of materials into the environment. Management believes that its current practices and procedures for the control and disposition of such wastes substantially comply with applicable federal and state requirements.

401(k) Plan: During 2004, the Company instituted a 401(k) plan covering substantially all employees with over three months of service and 21 years of age. At its discretion, the company may match a certain percentage of the employees' contributions to the Plan. The matching percentage is determined annually by the Board of Directors. Contributions to the Plan by the Company totaled $35,500 during 2004.

Restoration, Removal and Environmental Matters: The estimated costs of restoration and removal of producing property well sites is generally less than the estimated salvage value of the respective property; accordingly, the Company did not provide for a liability accrual prior to the adoption of SFAS 143 effective January 1, 2003. The estimated future costs for known environmental remediation requirements are accrued when it is probable that a liability has been incurred and the amount of remediation costs can be reasonably estimated. For wells that are drilled during the year, this generally occurs when the well is completed for production. See Note D.

Recent Accounting Pronouncements: In May 2003, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity" ("SFAS No. 150"). This statement requires that an issuer classify a financial instrument that is within its scope as a liability because the financial instrument embodies an obligation of the issuer. SFAS No. 150 is effective for all financial instruments entered into or modified after May 31, 2003 and requires reclassification of existing financial instruments in financial statements for the first interim period beginning after June 15, 2003. The mandatorily redeemable preferred stock discussed in Note E to the Audited Consolidated Financial Statements is recorded as a liability in accordance with this Statement.

On January 1, 2004, the Company adopted FASB Interpretation No. 46R, "Consolidation of Variable Interest Entities" ("FIN 46R"). This interpretation addresses consolidation of business enterprises of variable interest. The adoption of FIN 46R did not have a material impact on the Company's financial position or results of operations.

NOTE A - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - continued

In December 2004, the FASB issued Statement 123R, "Share-Based Payment (Revised 2004)" ("SFAS No. 123R"), effective for public companies for interim or annual periods beginning after June 15, 2005. SFAS No. 123R eliminates the ability to account for stock-based compensation using APB 25 and requires that these transactions be recognized as compensation cost in the income statement based on their fair values on the date of grant. The transition provisions require the "modified prospective method" be applied to all new or modified awards and the remaining expense for unvested options. The expected impact to the Company for options and warrants currently granted is expected to be approximately $123,000 in the second half of 2005, and $180,000 during 2006.

In February 2005, the FASB released for public comment proposed Staff Position FAS 19-a "Accounting for Suspended Well Costs." This proposed staff position would amend FASB Statement No. 19 "Financial Accounting and Reporting by Oil and Gas Producing Companies" and provides guidance regarding the capitalization of exploratory well costs pending determination of reserves to companies who use the successful efforts method of accounting. The proposed position states that exploratory well costs should continue to be capitalized if: 1) a sufficient quantity of reserves are discovered in the well to justify its completion as a producing well and 2) sufficient progress is made in assessing the reserves and the well's economic and operating feasibility. If the exploratory well costs do not meet both of these criteria, these costs should be expensed, net of any salvage value. Additional disclosures are required to provide information about management's evaluation of capitalized exploratory well costs. In addition, the Staff Position requires the disclosure of: 1) net changes from period to period of capitalized exploratory well costs for wells that are pending the determination of proved reserves, 2) the amount of exploratory well costs that have been capitalized for a period greater than one year after the completion of drilling and 3) an aging of exploratory well costs suspended for greater than one year with the number of wells it related to. Further, the disclosures should describe the activities undertaken to evaluate the reserves and the projects, the information still required to classify the associated reserves as proved and the estimated timing for completing the evaluation. When finalized, the adoption of this Staff Position is not expected to have a material impact on the Company's financial position or results of operations. As of December 31, 2004, the Company has no capitalized exploratory drilling costs pending the determination of proved reserves.

NOTE B - PROPERTY AND EQUIPMENT

Property and equipment consists of the following at December 31:

	2004	**2003**
Oil and gas properties	$131,328,759	$92,715,667
Other property and equipment	1,967,102	1,804,096
Total Property and Equipment	133,295,861	94,519,763
Accumulated depreciation, depletion and amortization	(35,439,338)	(26,164,119)
Reserve for impairment on unproved properties	(3,020,047)	(2,199,817)
Net Property and Equipment	$94,836,476	$66,155,827

NOTE C - LONG-TERM DEBT

Long-term debt consists of the following at December 31:

	2004	2003
Note payable to a financial institution under new bank credit facility (see below), with interest at LIBOR or prime plus applicable margin, monthly payments of interest only, with maturity in 2007, and collateralized by all of the Company's proven oil and gas properties.	$17,099,237	-
Note payable to a financial institution under a bank credit facility, with interest at prime, monthly payments of interest only, with maturity in 2006, and collateralized by accounts receivable and certain oil and gas properties. Replaced by above new Facility in 2004.	-	$14,000,000
Note payable to financing company, with interest at 12.61%, due in monthly installments of $22,404, with final payment in 2005, and collateralized by compressor equipment.	69,957	311,010
Note payable to an individual, with interest at 4.25%, due in annual installments of $1,406,422, with final payment in 2005, and unsecured.	1,349,086	2,644,671
Note payable to financing company, with interest at 11.85%, due in monthly installments of $834, with final payment in 2005, and collateralized by office equipment.	4,047	12,986
Installment notes to insurance company, with interest from 4.45% to 8.75%, due in current monthly installments of $36,279, with final payment in 2005, and unsecured.	243,376	209,217
Total long-term debt	18,765,703	17,177,884
Less current portion	(1,666,466)	(1,752,286)
Long-term portion of debt	$17,099,237	$15,425,598

The following is a schedule of principal maturities of long-term debt as of December 31, 2004:

Year Ended December 31,	Amount
2005	$ 1,666,466
2006	-
2007	17,099,237
	$18,765,703

Bank Credit Facility: On June 30, 2004, the Company closed on a $50 million senior secured revolving credit facility with Guaranty Bank (the "Facility" or "credit facility"). The new facility has a three-year term expiring in 2007. It replaces TXCO's prior $25 million credit facility with Hibernia National Bank, which was scheduled to mature in 2006. See discussion in Prior Facility below.

NOTE C - LONG-TERM DEBT - continued

The credit facility is collateralized by all of the Company's proven oil and gas properties, with an initial borrowing base of $12.3 million, based on then current levels of TXCO's oil and gas reserves, and features semi-annual redeterminations. The borrowing base was increased to $20,750,000 in October 2004. At December 31, 2004, the Company had outstanding $17.1 million with a weighted average interest rate of 4.65%, and an unused borrowing base of $3,650,000. The unused borrowing base at March 1, 2005, was $351,000. Interest under the new facility will be as much as 0.25 percentage point less than the former credit agreement, based on, at TXCO's option, (a) the London Interbank Offered Rate (LIBOR) plus an applicable margin ranging from 2.00% to 2.50% or (b) prime plus an applicable margin ranging from 0.00% to 0.25%. The Facility provides the lender a commitment fee equal to 0.5%, per annum on the unused borrowing base.

When borrowing under the Facility exceeds 50% of the borrowing base, the Company is required to hedge volumes equivalent to 50% of its production levels at the inception of the Facility. The Company entered into financial price hedges in October 2004. In early March 2005, the Company entered into additional financial price hedges.

The Facility contains additional terms and conditions consistent with similarly positioned companies. These conditions include various restrictive covenants such as minimum levels of interest coverage, tangible net worth and current ratio, a maximum debt to EBITDAX ratio, restricting the payment of dividends other than the dividends payable under the redeemable preferred stock, and prohibiting a change of control or incurring additional debt. At December 31, 2004, the Company was not in compliance with the current ratio covenant. Concurrently, on March 15, 2005, TXCO received a commitment from Guaranty Bank to increase its borrowing base to $26.5 million from the previous amount of $20.75 million, as well as a waiver for the covenant requirement at December 31, 2004. The Company expects to be in compliance with this covenant at March 31, 2005 and subsequent periods. Accordingly the Facility is classified as long-term.

Prior Facility: On March 4, 2002, the Company entered into a $25 million oil and gas reserve-based Revolving Credit Facility with Hibernia National Bank providing a credit line with an initial borrowing base set at $5 million. The borrowing base was subsequently increased based on reserves, and amendments were made during 2003 that modified the covenant terms and extended the termination date. At December 31, 2003, the borrowing base was $14 million, which was fully utilized. Interest was paid monthly, with principal due at maturity in March 2006. Borrowings under this facility had been reduced to $6.1 million prior to its replacement by the new credit facility described above.

Redeemable Preferred Stock Series B: In August 2003, the Company issued 16,000 shares of mandatorily redeemable preferred stock. This stock is classified as debt in accordance with SFAS 150. See Note E.

Letter of Credit Agreement: In connection with the financial price hedges, the Company entered into a one-year letter of Credit Agreement (L/C) with Guaranty Bank in October 2004. This agreement provides for the issuance of a Standby Letter of Credit representing a Hedge Commodity Agreement or Rate Management Transaction issued outside of the original borrowing base as stated in the Facility. The agreement requires the payment of administrative fees ranging from 2.0% to 2.5% per annum of the face amount of the L/C. The initial L/C amount was set at $1 million and subsequently increased to $2 million. No drafts or advances have been made against these L/C's through March 15, 2005.

Installment Agreement: In January 2003, the Company entered into an unsecured installment obligation related to additions to its oil and gas properties with imputed interest at 4.25%. The final payment was paid with the January 2005 installment of $1.4 million.

NOTE D - ASSET RETIREMENT COSTS AND OBLIGATIONS

The Company adopted the provisions of Statement of Financial Accounting Standards No. 143 "Accounting for Asset Retirement Obligations," on January 1, 2003. This Statement requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. In addition, the associated asset retirement costs are required to be capitalized as part of the carrying amount of the long-lived asset.

NOTE D - ASSET RETIREMENT COSTS AND OBLIGATIONS - continued

Upon adoption of this Statement, the Company recorded an asset retirement obligation of $1.3 million to reflect the Company's legal obligations related to future plugging and abandonment of its wells and gathering system, as well as, an increase to proved oil and gas properties of $1.2 million, and an expense of $74,000 constituting the cumulative effect of adoption. The new Statement had no material impact on income before the cumulative effect of adoption in 2003.

The following is a reconciliation of the asset retirement obligation for the years presented in the Consolidated Balance Sheets:

Initial adoption, January 1, 2003	$1,300,000
Liabilities incurred	180,000
Liabilities settled	-
Accretion expense	57,600
Balance, December 31, 2003	$1,537,600
Liabilities incurred	120,000
Liabilities settled	-
Accretion expense	22,000
Balance, December 31, 2004	$1,679,600

NOTE E - REDEEMABLE PREFERRED STOCK, SERIES B

In August 2003, the Company issued 16,000 preferred shares with a stated value of $1,000 each, and 2,133,333 common shares, in a private placement, raising a total of approximately $15.0 million after offering costs. The common stock is restricted from trading in a public transaction for one year from issuance, and the Company has the option to repurchase up to one-half of the common stock at a purchase price of $6.00 per share for a period of two years. The Redeemable Preferred Stock is classified as a long-term liability on the balance sheet.

The Preferred yields a dividend equal to 8% of stated value that is classified as interest expense, payable quarterly, for the first three years, increasing to 10% thereafter. It is redeemable at any time at the Company's option at the full stated value of $16 million, but must be redeemed in August 2009. In the event of default or liquidation of the Company, the Preferred is payable at the full stated value of the shares that remain outstanding, plus any accrued and unpaid dividends. A change in control of the Company, as defined, is considered a liquidating event under the agreement.

The Preferred was initially recorded at its fair value of $9.8 million and will be accreted to its full stated value over the six-year redemption period. The accretion is recorded as interest expense. The Preferred shares have information rights and a right to representation by one director and one board observer on the TXCO Board of Directors.

NOTE F - STOCKHOLDERS' EQUITY

Preferred Stock: The Company has authorized 10,000,000 shares of preferred stock. At December 31, 2004, there were no Series A preferred shares issued and outstanding. The Board of Directors has not established terms of the stock. In 2003, the Company issued 16,000 shares of redeemable preferred stock, Series B, all of which is outstanding at December 31, 2004. See Note E.

NOTE F - STOCKHOLDERS' EQUITY-continued

Private Placement - 2004: In May 2004, TXCO closed on a private placement of 4,266,668 shares of its common stock at a purchase price of $3.75 per share for net proceeds of $15.0 million. Included are warrants for an additional 1,280,000 common shares exercisable at $4.25 per share. The warrants became exercisable in November 2004 and expire in May 2008. Purchasers were private, U.S.-based investment funds. Proceeds from the private placement were used to expand the Company's capital expenditure program, restore balance sheet liquidity, complement on-going operations and provide for general corporate purposes.

Private Placement - 2003: In August 2003, the Company issued 2,133,333 shares of its common stock in conjunction with a private placement that included redeemable preferred stock. See Note E for further details. All of the common stock issued was restricted from trading in a public transaction for one year from issuance, and the Company has the option to repurchase up to one-half of the common stock at a purchase price of $6.00 per share for a period of two years from closing.

Stockholder Rights Plan: On June 29, 2000, the Company adopted a Rights Plan (the "Rights Plan") whereby a dividend of one preferred share purchase right (a "Right") was paid for each outstanding share of TXCO common stock. The Rights Plan is designed to enhance the Board's ability to prevent an acquirer from depriving stockholders of the long-term value of their investment and to protect shareholders against attempts to acquire the Company by means of unfair or abusive takeover tactics. The Rights will be exercisable only if a person acquires beneficial ownership of 15% or more of TXCO common stock (an "Acquiring Person"), or commences a tender offer which would result in beneficial ownership of 15% or more of such stock. When they become exercisable, each Right entitles the registered holder to purchase from TXCO .001 share of Series A Preferred Stock, subject to adjustment under certain circumstances.

Upon the occurrence of certain events specified in the Rights Plan, each holder of a Right (other than an Acquiring Person) may purchase, at the Right's then current exercise price, shares of TXCO common stock having a value of twice the Right's exercise price. In addition, if, after a person becomes an Acquiring Person, TXCO is involved in a merger or other business combination transaction with another person in which TXCO is not the surviving corporation, or under certain other circumstances, each Right will entitle its holder to purchase, at the Right's then current exercise price, shares of common stock of the other person having a value of twice the Right's exercise price. The Rights Plan generally may be amended by the Company without the approval of the holders of the Rights prior to the public announcement by TXCO or an Acquiring Person that a person has become an Acquiring Person.

Unless redeemed by TXCO earlier, the Rights will expire on June 29, 2010. The Company will generally be entitled to redeem the Rights in whole, but not in part, at $0.01 per Right, subject to adjustment. No Rights were exercisable under the Rights Agreement at December 31, 2004.

Stock Repurchase: On June 27, 2001, the Company's Board of Directors approved a common share buyback program to purchase up to $2 million of the Company's common shares in the open market or privately negotiated treasury purchases. The timing and amount of these stock repurchases are determined at the discretion of management. During 2001, the Company purchased 99,800 shares of its common stock at a cost of $246,007 under this program. The Company has not purchased any common stock under this program since 2001.

Dividend Restriction: The Bank Credit Facility agreement limits dividends which may be declared and paid to such amounts as required under the terms of Redeemable Preferred Stock, Series B. The Agreement further limits the declaration, or payment, of dividends to no more than 50% of net income for the prior year-end, after consideration of the Series B requirements.

Commission Payment: In the first quarter of 2004, a commission of approximately $223,000 was paid to a Director of the Company under an agreement in place since prior to the appointment of the director to the Board. This fee was related to the exercise of warrants to purchase 1.2 million shares of the Company's common stock in January and February of 2004.

NOTE F - STOCKHOLDERS' EQUITY-continued

Stock Based Employee Compensation Plan: The Company grants options to its officers, directors, and key employees under its 1995 Flexible Incentive Plan (the "Plan"), as amended. The Plan, as amended, is authorized to grant options to management, directors, and key employees for up to 10% of the outstanding common stock. At December 31, 2004, 2,801,056 shares were authorized for grant and 812,556 shares remained available for grant. All options granted have 10-year terms that vest and become fully exercisable based on the specific terms imposed at the date of grant.

Pro forma information included in Note A regarding net income and earnings per share as required by SFAS No. 123 is computed using a Black-Scholes option pricing model. The fair value for these options was estimated at the date of grant with the following weighted-average assumptions for the year ended December 31:

	2004	2003	2002
Risk-free interest rate	3.35%	4.17%	*
Expected dividend yield	0%	0%	*
Expected volatility of common stock	.47	.43	*
Expected weighted-average life of option	5 years	5 years	*

* No grants were awarded during 2002.

The Black-Scholes option valuation model was developed for use in estimating the fair value of traded options that have no vesting restrictions and are fully transferable. In addition, option valuation models require the input of highly subjective assumptions including the expected stock price volatility. Because the Company's employee stock options have characteristics significantly different from those of traded options, and because changes in the subjective input assumptions can materially affect the fair value estimate, in management's opinion, the existing models do not necessarily provide a reliable single measure of the fair value of its employee stock options.

In December 2004, the FASB issued Statement 123R, "Share-Based Payment," which requires all companies to measure compensation cost for all share-based payments (including employee stock options) at fair value, effective for public companies for interim or annual periods beginning after June 15, 2005. See the discussion in Note A for the expected impact to the Company of options currently outstanding.

A summary of the Company's stock option activity and related information is as follows:

	Shares	Wt.-Avg. Exercise Price	Wt.-Avg. Fair Value of Options Granted	Exercisable at End of Period
Outstanding at December 31, 2001	1,604,000	$2.43		649,000
Granted	-	-	N/A	
Exercised	(113,000)	1.53		
Forfeited	(28,000)	2.96		
Outstanding at December 31, 2002	1,463,000	2.49		999,500
Granted	220,000	4.65	$1.74	
Exercised	-	-		
Forfeited	-	-		
Outstanding at December 31, 2003	1,683,000	$2.78		1,163,000
Granted	197,500	5.00	$1.92	
Exercised	(35,000)	2.81		
Forfeited	(30,000)	4.59		
Outstanding at December 31, 2004	1,815,500	$2.99		1,218,000

THE EXPLORATION COMPANY
Notes to Audited Consolidated Financial Statements
Years Ended December 31, 2004, 2003 and 2002

NOTE F - STOCKHOLDERS' EQUITY - continued

The following table summarizes information about the options outstanding at December 31, 2004:

	Options Outstanding			Options Exercisable	
Exercise Price	**Number Outstanding**	**Wt.-Avg. Remaining Contractual Life**	**Wt.-Avg. Exercise Price**	**Number Exercisable**	**Wt.-Avg. Exercisable Price**
$0.98	25,000	3.83 years	$0.98	25,000	$0.98
1.25	8,000	3.68 years	1.25	8,000	1.25
2.12	713,000	3.64 years	2.12	413,000	2.12
2.62	50,000	1.68 years	2.62	50,000	2.62
2.75	100,000	0.12 years	2.75	100,000	2.75
2.78	75,000	5.40 years	2.78	75,000	2.78
2.96	162,000	6.59 years	2.96	162,000	2.96
3.09	300,000	4.08 years	3.09	300,000	3.09
4.38	120,000	8.47 years	4.38	60,000	4.38
5.00	187,500	9.75 years	5.00	-	5.00
5.17	75,000	8.64 years	5.17	25,000	5.17
	1,815,500		$2.99	1,218,000	$2.73

Stock Warrants: The following is a summary of warrants outstanding at December 31, 2004:

Purpose of Warrants	Number of Shares	Range of Prices	Wt.-Avg. Exercise Price	Wt.-Avg. Remaining Contractual Life
Financing	1,591,833	$2.88 - $6.00	$4.06	2.7 year

In January 2005, warrants were exercised to purchase 155,000 shares of the Company's common stock at $2.875 per share. Additionally, in February 2005, warrants to purchase 40,000 shares at $6.00 per share expired. After these events, 1,396,833 warrants remain outstanding with a weighted average exercise price of $4.13.

NOTE G - EARNINGS PER SHARE

The following is a reconciliation of the numerator and denominator of the basic and diluted earnings per share computation:

	Shares	Income (Loss)	Per Share Amount
Year Ended December 31, 2004:			
Basic EPS:			
Net income	26,066,299	$2,796,828	$ 0.11
Effect of dilutive options	905,141	-	0.01
Dilutive EPS	26,971,440	$2,796,828	$ 0.10
Year Ended December 31, 2003:			
Basic EPS:			
Net income	20,781,223	$ 40,877	$ 0.00
Effect of dilutive options	514,034	-	-
Dilutive EPS	21,295,257	$ 40,877	$ 0.00
Year Ended December 31, 2002:			
Basic EPS:			
Net income	19,080,847	$ (310,970)	$(0.02)
Effect of dilutive options	-	-	-
Dilutive EPS	19,080,847	$ (310,970)	$(0.02)

The 2002 loss per share does not include the effect of options and warrants, as their impact would be antidilutive.

NOTE H - OPERATING LEASES

The Company leases its primary office space through August 2007, and certain oil field equipment through November 2006. The Company incurred rent expense of approximately $582,000 in 2004, $394,000 in 2003 and $261,000 in 2002. Future minimum rentals under all noncancelable leases are as follows:

Year Ended December 31,	Amount
2005	$390,000
2006	320,000
2007	195,000
2008	13,000
2009	12,000

NOTE I - INCOME TAXES

The components of the Company's income taxes were as follows for the years ended December 31:

	2004	2003	2002
Current federal tax benefit (expense)	$(146,000)	$(50,000)	$75,000
Deferred federal tax benefit (expense)	-	-	-
Income tax benefit (expense)	$(146,000)	$(50,000)	$75,000
Deferred tax assets:			
Tax net operating loss carryforwards	$1,200,000	$3,600,000	$4,600,000
Impairment of oil and gas properties	6,100,000	4,700,000	3,400,000
Net deferred tax assets	7,300,000	8,300,000	8,000,000
Deferred tax liability:			
Accumulated depreciation	(425,000)	(75,000)	-
Gross deferred tax liability	(425,000)	(75,000)	-
Net deferred tax assets	6,875,000	8,225,000	8,000,000
Less valuation allowance	(1,642,282)	(2,992,282)	(2,767,282)
Deferred income tax asset recorded	$5,232,718	$5,232,718	$5,232,718

The Company's available net operating loss carryforwards ("NOLs") of approximately $3,600,000 ($1,200,000 tax benefit) at December 31, 2004, expire in stages from 2007 to 2018. Realization of deferred tax assets associated with the NOLs is dependent upon generating sufficient taxable income prior to their expiration. The Company believes that there is a risk that certain of its net deferred tax assets may not be realized, and, accordingly, a valuation allowance has been provided. Although realization is not assured for the net deferred tax asset, the Company believes it is more likely than not that they will be realized through future taxable earnings. However, the net deferred tax assets could be reduced further if the Company's estimate of taxable income in future periods is significantly reduced.

The differences between the expected federal income taxes and the Company's actual taxes are as follows:

	2004	2003	2002
Expected federal tax benefit (expense)	$(146,000)	$(19,000)	$131,000
Other changes	-	(31,000)	(56,000)
Income tax benefit (expense)	$(146,000)	$(50,000)	$ 75,000

NOTE J - MAJOR CUSTOMERS

Sales to unrelated entities which individually comprised greater than 10% of total revenues are as follows:

	A	B	C	D
Year ended December 31, 2004	14%	13%	13%	9%
Year ended December 31, 2003	n/a	39%	18%	20%
Year ended December 31, 2002	n/a	14%	10%	23%

NOTE K - DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITY

The Company periodically enters into derivative agreements to hedge its exposure to price fluctuations on natural gas and crude oil production. At December 31, 2004, the Company had two ratio swap agreements open for monthly notional volumes of 15,000 barrels of crude oil (BO) and 140,000 MMBtu of natural gas through October of 2005. These were structured with floor prices of $39.10 per BO and $5.37 per MMBtu and allow the Company to participate in 75% of prices above these floors.

The Consolidated Balance Sheet at December 31, 2004, includes a receivable for derivative fair value gain of $134,000 in the Prepaid Expenses and Other line item. A derivative fair value loss of $19,000 was recognized on the Consolidated Statement of Operations in 2004. This loss is the net of the unrealized fair value gain of $134,000 and the cash settlement losses of $153,000 for closed months. At February 28, 2005, the mark to market valuation resulted in an unrealized liability of approximately $700,000. If product prices remain at the current levels, the Company may record a loss of approximately $800,000 during the first quarter of 2005.

NOTE L - OIL AND GAS PRODUCING ACTIVITIES AND PROPERTIES

Capitalized Costs and Costs Incurred Relating to Oil and Gas Activities

The Company's investment in oil and gas properties is as follows at December 31:

	2004	2003
Proved properties	$90,947,555	$62,871,668
Less accumulated depreciation, depletion and amortization	(34,470,127)	(25,395,371)
Net proved properties	56,477,428	37,476,297
Unproved properties:		
Coalbed methane properties (1)	8,184,737	7,871,096
Drilling in-progress	19,468,414	10,792,940
Oil and gas leasehold acreage	12,728,052	11,179,963
Total unproved properties	40,381,203	29,843,999
Less reserve for impairment	(3,020,047)	(2,199,817)
Net unproved properties	37,361,156	27,644,182
Net capitalized cost	$93,838,584	$65,120,479

(1) Subsequent to year-end, the Company sold a 50% interest in these properties. See discussion in Note M.

THE EXPLORATION COMPANY
Notes to Audited Consolidated Financial Statements
Years Ended December 31, 2004, 2003 and 2002

NOTE L - OIL AND GAS PRODUCING ACTIVITIES AND PROPERTIES - continued

Costs incurred, capitalized, and expensed in oil and gas producing activities are as follows for the years ended December 31:

	2004	2003	2002
Property acquisition costs, unproved	$11,106,922	$11,744,304	$ 5,866,791
Property development and exploration costs:			
Conventional oil and gas properties	31,873,453	27,141,935	14,117,482
Coalbed methane properties	313,641	571,334	1,047,256
Gathering system	101,474	310,096	5,649,181
Depreciation, depletion and amortization	9,646,029	8,259,914	6,306,511
Depletion per equivalent Mcf of production	1.97	1.71	1.44

Oil and Gas Reserves (Unaudited)

The estimates of the Company's proved reserves and related future net cash flows that are presented in the following tables are based upon estimates made by independent petroleum engineering consultants. The Company's reserve information was prepared as of each respective year-end. There are many inherent uncertainties in estimating proved reserve quantities, projecting future production rates, and timing of development expenditures. Accordingly, these estimates are likely to change, as future information becomes available. Proved developed reserves are the estimated quantities of crude oil, condensate, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Changes in estimated net quantities of conventional oil and gas reserves, all of which are located within the United States, are as follows for the years ended December 31:

	2004	2003	2002
Proved developed and undeveloped reserves:			
Natural gas (Mcf):			
Beginning of year	15,624,000	14,675,000	10,976,000
Extensions and discoveries	6,432,000	5,037,000	5,103,000
Reserves purchased	557,000	671,000	-
Sales volumes	(2,975,000)	(2,108,000)	(2,487,000)
Revisions of previous engineering estimates	(1,937,000)	(2,651,000)	1,083,000
End of year	17,701,000	15,624,000	14,675,000
Crude Oil (Bbls):			
Beginning of year	2,129,000	1,479,000	294,000
Extensions and discoveries	1,396,000	1,115,000	600,000
Reserves purchased	-	1,000	674,000
Sales volumes	(321,000)	(454,000)	(314,000)
Revisions of previous engineering estimates	170,000	(12,000)	225,000
End of year	3,374,000	2,129,000	1,479,000
Proved developed reserves:			
Natural gas (Mcf):			
Beginning of year	9,896,000	6,213,000	5,102,000
End of year	13,087,000	9,896,000	6,213,000
Crude Oil (Bbls):			
Beginning of year	1,340,000	988,000	133,000
End of year	1,688,000	1,340,000	988,000

NOTE L - OIL AND GAS PRODUCING ACTIVITIES AND PROPERTIES - continued

The Company's coalbed methane properties are classified as unproved as the project is still dewatering at December 31, 2004.

The following table sets forth a standardized measure of the estimated discounted future net cash flows attributable to the Company's proved developed and undeveloped oil and gas reserves. Prices used to determine future cash inflows were based on the respective year-end weighted average sales prices utilized for the Company's proved developed reserves which were $6.06, $5.77 and $4.90 per Mcf of gas and $41.15, $30.06 and $28.71 per barrel of oil as of December 31, 2004, 2003 and 2002. The future production and development costs represent the estimated future expenditures to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. Future income tax expense was computed by applying statutory income tax rates to the difference between pretax net cash flows relating to the Company's reserves and the tax basis of proved oil and gas properties and available operating losses and temporary differences.

Standardized measure:	2004	2003	2002
Future cash inflows	$246,073,000	$154,215,000	$114,337,000
Future production and development costs	(113,353,000)	(65,263,000)	(49,207,000)
Future income tax expense	(25,152,000)	(14,802,000)	(10,400,000)
Future net cash flows	107,568,000	74,150,000	54,730,000
10% annual discount to reflect timing of net cash flows	(42,106,000)	(26,801,000)	(16,583,000)
Standardized measure of discounted future net cash flows relating to proved reserves	$65,462,000	$ 47,349,000	$ 38,147,000

The principal factors comprising the changes in the standardized measure of discounted future net cash flows is as follows for the years ended December 31:

	2004	2003	2002
Standardized measure, beginning of year	$47,349,000	$38,147,000	$13,983,000
Extensions and discoveries	46,763,000	34,608,000	27,024,000
Reserves purchased	2,533,000	1,591,000	4,645,000
Sales and transfers, net of production costs	(23,133,000)	(18,482,000)	(10,838,000)
Revisions in quantity and price estimates	2,547,000	(2,491,000)	11,966,000
Net change in income taxes	(5,862,000)	(2,209,000)	(7,235,000)
Accretion of discount	(4,735,000)	(3,815,000)	(1,398,000)
Standardized measure, end of year	$65,462,000	$47,349,000	$38,147,000

NOTE M - SUBSEQUENT EVENTS

In February 2005, TXCO entered into an asset exchange agreement with Arrow River Energy LP ("Arrow River") and CMR Energy LP ("CMR"), under which TXCO receives a 50% working interest in 174,460 gross acres (69,500 net acres), as well as 3-D seismic data covering 140 square miles (89,600 acres) over a portion of the new acreage. TXCO will serve as operator and Arrow River reserves an after-payout, term net-profits interest in new wells drilled on the new acreage.

In exchange, Arrow River and CMR collectively receive a 50% working interest in 106,500 leasehold acres comprised of three tracts within TXCO's existing acreage block. CMR, which currently serves as operator on deeper portions of the Comanche Ranch lease, will assume operations on these tracts and all existing shallow wells.

On March 15, 2005, TXCO received a commitment from Guaranty Bank to increase its borrowing base to $26.5 million from the previous amount of $20.75 million.

NOTE N - Selected Quarterly Financial Information (Unaudited)

(In thousands, except per share amounts)	**First**	**Second**	**Third**	**Fourth**	**Total**
2004					
Total revenues	$11,367	$14,625	$15,317	$16,426	$57,735
Income from operations	807	1,144	1,330	2,606	5,887
Net income	69	372	600	1,756	2,797
Earnings Per Share: (1)					
Basic	$0.00	$0.01	$0.02	$0.06	$0.11
Diluted	$0.00	$0.01	$0.02	$0.06	$0.10
2003					
Total revenues	$9,088	$9,869	$9,394	$11,194	$39,545
Income (loss) from operations	884	199	437	(74)	1,446
Net income (loss)	725	10	58	(752)	41
Earnings Per Share: (1)					
Basic:					
Income (loss) before cumulative effect of change in accounting principle, net of tax	$0.04	$0.00	$0.00	$(0.04)	$0.00
Net income (loss)	$0.04	$0.00	$0.00	$(0.04)	$0.00
Diluted:					
Income (loss) before cumulative effect of change in accounting principle, net of tax	$0.04	$0.00	$0.00	$(0.04)	$0.00
Net income (loss)	$0.04	$0.00	$0.00	$(0.04)	$0.00

(1) Quarterly earnings per share is based on the weighted average number of shares outstanding during the quarter. Because of the increase in the number of shares outstanding during the quarters due to exercises of warrants and stock options, as well as newly issued shares, the sum of quarterly earnings per share may not equal earnings per share for the year.

THE EXPLORATION COMPANY
Schedule II - Valuation and Qualifying Reserves

	Balance Beginning of Period	Charged to Costs and Expense	Deductions	Balance End of of Period
Year Ended December 31, 2004				
Allowance for doubtful accounts, trade accounts	$ 27,000	$ -	$ -	$ 27,000
Impairment of oil and gas properties	2,199,817	882,667	(62,437)	3,020,047
Deferred tax asset valuation allowance	2,992,282	-	(1,350,000)	1,642,282
Year Ended December 31, 2003				
Allowance for doubtful accounts, trade accounts	$ 27,000	$ -	$ -	$ 27,000
Impairment of oil and gas properties	1,488,492	761,625	(50,300)	2,199,817
Deferred tax asset valuation allowance	2,767,282	225,000	-	2,992,282
Year Ended December 31, 2002				
Allowance for doubtful accounts, trade accounts	$ 27,000	$ -	$ -	$ 27,000
Impairment of oil and gas properties	861,313	627,179	-	1,488,492
Deferred tax asset valuation allowance	2,637,282	130,000	-	2,767,282