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

FORM 10-K

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

For the Fiscal Year Ended December 31, 2003

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 [X] 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. [X].

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

The aggregate market value of the voting stock (which consists solely of shares of Common Stock) held by non-affiliates of the registrant was $74.8 million based upon the closing price of $4.25 per share of such stock as reported by the NASDAQ Small-Cap Market under the symbol TXCO on June 30, 2003.

The number of shares outstanding of the Registrant's Common Stock as of March 5, 2004, was 23,381,145 of which 18,828,401 shares were held by non-affiliates.

Documents Incorporated by Reference: **None**

For more information and a print friendly version of this document **go to www.txco.com.**

INDEX AND
CROSS REFERENCE SHEET

PART I

ITEM 1. BUSINESS

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's long-term 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 1998 through 2003, combined with the re-investment of TXCO's growing positive cash flow provided from operations, reaffirmed Management's ongoing strategy for improved shareholder value by maintaining its 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 March 2002 TXCO's marked growth was further affirmed by a new $25 million reserve-based credit facility. The credit facility was established to complement the Company's expansive drilling program. The Company has remained focused on the Maverick Basin for 15 years 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. The gathering system acquisition enables TXCO to realize higher prices for its natural gas and better share in proceeds from extraction of natural gas liquids.

TXCO achieved significant progress in many key areas of operations with record drilling activity during 2003. These results include a 186% drill bit reserve replacement rate and a 9.0 billion cubic feet equivalent ("Bcfe") increase in reserves, while positive cash flow provided from operations reached $15.2 million, a 105% 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 last five years, TXCO has expanded and developed its natural gas and oil production base significantly in the Company's core area of operation, the Maverick Basin of South Texas. This overall growth is primarily attributable to the Company's focused, ongoing drilling activities fed by the expansive array of drilling opportunities across its lease block. This growth has been enhanced through the ongoing acquisition of new non-developed leasehold acreage as well as the acquisition of producing properties adjacent to its 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 2003, the Company expanded its Maverick Basin lease block to almost 480,000 contiguous acres. In addition, TXCO successfully completed a total of 56 wells in various horizons, including 37 new oil wells in the San Miguel, Georgetown, and Glen Rose formations, while 19 new gas wells were completed in the Glen Rose, Georgetown and Escondido formations

During 2003, the Company expanded its oil and gas reserves and production base by pursuing exploration in seven distinct Maverick Basin plays, ranging from the shallow Escondido at 1,200 feet to the deep Jurassic at over 22,000 feet of depth. New seismic processing techniques were applied during the year resulting in the enhanced 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 2004, in descending depth order, include: accelerating Coalbed Methane ("CBM") gas production from dewatering Olmos coals; 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; additional Comanche lease horizontal wells targeting Glen Rose porosity oil production; and completion of the Taylor 1-132 wildcat well in pursuit of deep Jurassic formation gas. As 2003 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 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 to continue the growth of its oil and gas reserves and production levels in 2004. TXCO's initial 2004 capital expenditure budget ("CAPEX") was set at $23.4 million, with 82% or $19.2 million earmarked for drilling 51 new wells and four re-entries targeting five primary horizons. The remaining $4.2 million will go toward seismic acquisition, pipeline infrastructure improvements, and includes $1.8 million for completion of in-progress wells. 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 2004, 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 2004, Management retains its ability to modify 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.

PRINCIPAL AREAS OF ACTIVITY

Oil and Gas Operations

Again in 2003, the Company actively developed its core mineral interests in the Maverick Basin in South Texas, and re-evaluated economic alternatives related to its remaining properties in the Williston Basin, primarily in North Dakota. These activities included the drilling or re-entry of 79 wells in South Texas during 2003, as compared to 41 in 2002. The Company also re-entered one well in North Dakota during 2003. The increase in 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 oil production levels and strong commodity prices, offset partially by a 15% decrease in Maverick Basin gas production during 2003, resulted in increased net cash provided by operating activities totaling $15.2 million in 2003 compared to $7.4 million in 2002.

The Company's strategy remains focused on its core oil and natural gas producing properties and higher margin exploration activities in the Maverick Basin. Although crude oil and natural gas prices increased in recent years, industry activity or interest has not returned to pre-1998 levels in the Williston Basin, the location of the only significant leasehold interest the Company holds outside the Maverick Basin. TXCO has continued efforts to either locate suitable joint venture partners, farmout, or sell its interest in the Williston Basin.

Maverick Basin

The Company has owned a 50% or greater leasehold interest in at least 50,000 contiguous acres in the Maverick Basin of Texas, since 1989. These holdings have increased to almost 480,000 acres through 2003, while TXCO's average leasehold interest is over 85%. The contiguous lease block is situated on the Chittim Anticline, a large regional structure, under which hydrocarbons have been found in at least 14 separate horizons dating back over 65 years. 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 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.

During the fourth quarter of 2003, TXCO completed its latest 3-D seismic survey covering more than 37 square miles (equivalent to 23,500 acres) of its Burr lease. Initial interpretations identified numerous drillable locations in the Georgetown, Glen Rose and Jurassic intervals. A portion of these locations has been included in the 2004 capital expenditure budget.

At year-end 2003 the Company had accumulated over 720 square miles of 3-D seismic data covering more than 95% of its 750-square-mile (equivalent to 480,000 acres) Maverick Basin lease block. This represents an increase of 265 square miles of 3-D data over year-end 2002, expanding the seismic coverage over a significant portion of the Chittim and Burr leases.

TXCO geologists and geophysicists have conclusively 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 included in the 2004 drilling program are described under the "Maverick Basin Plays" heading later in this section.

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. Subsequent to year-end 2003, a second installment of $1.4 million was made, with a final installment of $1.4 million due in January 2005.

Subsequent to year-end 2003, TXCO signed a letter of intent to acquire a 50% to 75% working interest ("WI") in a 12,200-acre prospect area located just south of the Company's lease block. TXCO anticipates closing in mid-March. A 3-D seismic survey of the prospect has been acquired and will be interpreted to locate prospective drilling locations.

2003 Drilling Activity Summary

TXCO participated in drilling a total of 71 gross wells and nine re-entries during 2003. Of the 80 total wells, 56 were successfully completed, one was a dry hole and 23 remained in progress at year-end. Completed Maverick Basin wells include 36 producing oil and 19 producing gas, while one well was dry. A total of 39 drilling wells remained in progress at year-end, including wells remaining from the prior year (see the "In Progress Recap" for further information). Two gas wells in progress at December 31, 2002 were completed in January 2003, one each on the Chittim and Ashtola-Johnston leases. Six of the nine re-entry attempts resulted in oil well completions in five different formations. In the Williston Basin in North Dakota, the Company recompleted the Sherry 1-16 oil well.

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

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

At year-end 2003, TXCO's net production reached 8.9 million cubic feet per day ("MMcfd") (gross 23.8 MMcfd) from 91 net gas wells plus 1,200 barrels of oil per day (gross 5,900 barrels of oil per day) from 186 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 - ***in descending depth order***

Escondido

TXCO drilled five shallow Escondido wells (100% WI) in 2003 on the eastern portion of its Comanche lease. Of these, three are producing, one was shut in and one was abandoned. The producing wells flowed an average of 132 thousand cubic feet per day (Mcfd) at December 31. At year-end 2003, total daily production from this interval was 397 Mcfd compared with 98 Mcfd at year-end 2002. No funds have been included in the initial 2004 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 1,200 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.

Gas production continues to rise as TXCO proceeds with the dewatering phase of its Olmos/coalbed methane project. At year-end 2003, 36 wells were producing 208 Mcfd of natural gas and 1,837 barrels of water per day ("BWPD") compared with 144 Mcfd and 1,975 BWPD at December 31, 2002. The Company believes that the next phase of this project will require 25 to 50 wells initially, during which the Company expects to establish economic gas production quantities. The Company may seek an industry partner or project type financing, which it believes is more suitable for this project due to its cash flow profile, as well as complementing the Company's existing capital structure. The Company may sell an interest in the CBM project to an industry partner with CBM expertise. To date, several potential industry partners have expressed an interest in TXCO's project. There are no new CBM wells included in the 2004 CAPEX budget. The Company expects that this project will add significant reserves in the coming years.

San Miguel Waterflood

Comanche Lease: 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. In conjunction with its CBM dewatering projects, TXCO has engineered a synergistic water disposal cost reduction program to dispose of the CBM water into a neighboring formation. In 2001, TXCO initiated a waterflood injection pilot program targeting oil production from the San Miguel formation, located about 400 feet below the base of the Olmos coal interval. A proven San Miguel waterflood oil field directly offsets the northern boundary of TXCO's Comanche lease. Conoco's Sacatosa (San Miguel) Field has produced over 42 million barrels of oil and 21 Bcf of gas since its discovery in 1956.

Conoco initiated waterflood operations in the San Miguel sand interval in 1966 and continues to successfully operate the huge field. Initial geologic and engineering studies indicate the San Miguel sand interval under TXCO's Comanche lease is a look-alike structure in size and structural position relative to Conoco's adjacent San Miguel waterflood field. Using its growing volume of CBM water production, TXCO added a second San Miguel waterflood pilot in 2002. Additional operating efficiencies were gained by re-entering existing vertical well bores acquired from previous operators. Company engineers selected and re-entered existing horizontal well bores in close proximity to the vertical wells in each of the pilots for recompletion as water injection wells. The development of this project is pending expansion of the CBM project that would provide additional injection water.

Pena Creek: In May 2002, the Company acquired the adjacent Pena Creek oil field in Dimmit County, Texas, which included 94 producing oil wells, 94 injection wells and 28 shut-in wells. During 2003, the Company drilled 23 infill wells targeting bypassed reserves, successfully completing 21 of those wells. Four of the 21 wells went on production during the fourth quarter. At year-end 2003, the field was producing approximately 463 barrels of oil per day ("BOPD") and 1,404 BWPD from the San Miguel formation, up from 265 BOPD and 651 BWPD at December 31, 2002. Net proved reserves at year-end for this field were estimated at 1.5 million barrels, up from 0.7 million barrels at year-end 2002, on a SEC PV-10 basis. The 10,000-acre Pena Creek lease 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.

During 2002, TXCO completed a 3-D seismic survey covering the Pena Creek field and surrounding acreage. The Company has completed an extensive geological, engineering and 3-D seismic review, including the review of historic well data acquired with the property. These evaluations have allowed 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, while, testing continues on the economic potential of two additional, overlying San Miguel sands. The 2004 CAPEX budget includes $2.7 million for 10 new wells in the San Miguel waterflood, and an additional $500,000 for injection well conversions.

Georgetown

Gross Production from the Georgetown formation reached 9.1 MMcfe per day at year-end 2003 from 27 wells, compared with 1.1 MMcfe per day from 13 wells at December 31, 2002. This eight-fold increase relates primarily to three new wells in the Comanche-Halsell field placed on production during the fourth quarter of 2003, adding a combined gross daily production at year-end 2003 of 7.6 MMcfe per day. TXCO has a 50% working interest in each of these wells (the Kothman 1-673, Myers 1-684 and Vivian 1-687).

TXCO had mixed success with the earlier deviated drilling techniques used in late 2002 and early 2003. Prior to utilizing a new seismic technique, the Georgetown had typically been a secondary target when lower zones proved unproductive.

TXCO and its partners drilled the last four wells in 2003 using a new seismic processing technique that more accurately predicts formation faults and fractures. By using this new processing technique, the Company has initially identified several hundred potential Georgetown well locations across the lease block. The technique does not differentiate the type of reservoir fluids to be recovered from the fracture network. TXCO has 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. 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 high initial production rates, which fall to lower, sustained rates. Netherland Sewell & Associates, Inc., the Company's Dallas based independent reservoir engineering firm, established initial proved reserves averaging 1.3 Bcfe per well for these first three TXCO-operated Georgetown gas wells as of year-end 2003. TXCO's internal reservoir engineers believe that proved reserves will increase as sufficient additional production history is established. Overall, TXCO drilled or re-entered 18 Georgetown wells in 2003, with only the last four wells utilizing the new seismic technique.

Through March 3, 2004, the Company has spudded seven Georgetown wells using the new technique. Of these new wells, five are being completed while two are currently drilling. Two wells spud in December 2003 have been completed in 2004, the Briscoe Saner 1-39 was producing 38 BOPD and the Covert 1-690 was producing 617 Mcfd, each at mid-February. These completions bring TXCO's string of Georgetown successes to eight in a row. The 2004 CAPEX budget includes $9.3 million for 25 new wells in this program, as well as $1.8 million for completion of wells in progress at year-end.

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 100,000-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. The joint venture partners completed the acquisition, also in 2001, 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 western-most portion of the seismic survey, a well targeting the Glen Rose formation was spudded in June 2001 on the Cinco Ranch portion of the prospect. Unfortunately the reef was water bearing. By year-end 2002, the partners completed the acquisition and processing of the entire 3-D survey. Additional seismically defined Glen Rose reefs were identified and a second well was planned targeting a particularly attractive prospect on TXCO's Comanche lease, which contained evidence of multiple Glen Rose reefs stacked over a previously unidentified structure. This well, which was the discovery well for the Comanche Halsell (6500) field, 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 spread over a 20 square-mile area. Because the 40-degree gravity oil is consistent over the entire area and contains no gas, the Company's engineers believe that all the productive wells will eventually be determined to be one field. The partners' engineering staffs have completed extensive reviews of the porosity intervals and its oil and water production profiles. Additionally, extensive 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.

Gross production from the Comanche Halsell (6500) Field, at year-end 2003, stood at 1,317 BOPD and 9,195 BWPD from 16 producing wells. This compares to a 2002 exit rate of 1,720 BOPD and 3,600 BWPD from seven producing wells. During 2003, six horizontal wells and seven vertical wells (drilled to delineate the areal extent of the porosity's oil-bearing rock) were drilled, raising the combined number of wells since the oil play's discovery in February 2002 to 27. 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 have not responded as expected, contributing to the overall decline in field production late in the year. TXCO engineers have believed for some time that drilling horizontal laterals parallel to, rather than crossing faults, while staying within the porosity zone, could result in enhanced oil production from this complex fractured reservoir. The Company has proposed using this technique for 2004 drilling in the porosity interval. Cumulative gross oil production has surpassed 1.4 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 tap the oil in the formation.

2004 Glen Rose porosity drilling has not resumed on the Comanche lease as expected with the end of the annual hunting season drilling moratorium in January 2004. At February 29, 2004, the field was producing 998 BOPD and 10,597 BWPD from 16 wells. The initial 2004 CAPEX budget includes only $4 million for eight new wells and four re-entries in this oil play. During 2003, TXCO negotiated to purchase Tom Brown, Inc.'s 30% non-operating working interest in the Comanche lease, in order to consolidate its ownership and enable TXCO to assume majority control over the overall project. TXCO's operating partner, Saxet Energy, Ltd., exercised their right to purchase Tom Brown's interest under a previous agreement between the parties, effectively preventing TXCO from assuming control or operator status. In January 2004, Saxet announced its intention to liquidate its holdings, including 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. Saxet's Management has advised TXCO that it is currently in the final phase of marketing its interest in the subject properties via private negotiations with various potential buyers. TXCO expects a sale would result in a new operator for the Comanche/Pena Creek Prospect, and is optimistic the change in operator will result in a resumption of 2004 exploration and development activities. Until such time as a final sale is concluded, TXCO cannot predict who the new owner will be, what the final sales price of the subject properties will be, or when 2004 exploration and development activities as directed by Saxet or its successor will return to normal on the Comanche/Pena Creek prospect.

Horizontal Glen Rose Shoal

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, which had logged or otherwise penetrated the structure while attempting completions in other oil or gas-bearing horizons. The Company elected to drill 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 March 1, 2004 of 880 MMcf, and was still producing approximately 550 Mcfd at that date. 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 successful horizontal Glen Rose shoal drilling program in 2003, drilling 11 successful gas wells in a row (47% to 62% WI). The Kincaid 1-220 (100% WI), drilled on a new shoal complex, currently is pending completion but does not look promising as the shoal appears to contain water. Three horizontal Chittim Glen Rose shoal wells started production in the fourth quarter. At December 31, gross production from the Chittim E. (Rodessa 5300) Field was 9.7 MMcfd and 58 BOPD from 25 wells, compared with 7.6 MMcfd and 45 BOPD from 14 wells at year-end 2002. The field has produced 4.8 Bcf since horizontal drilling techniques have been applied.

At December 31, 2003, the Company's independent engineering firm estimated the proved undeveloped reserves represented by the 11 identified locations to be 11.9 Bcf with 4.5 Bcf, net to TXCO.

Plans for 2004 include drilling eight low-risk horizontal Glen Rose shoal or reef wells estimated to cost $3.2 million. In mid-February 2004, TXCO spud the Chittim 4-128H-C targeting the Glen Rose shoal, which is currently drilling.

Jurassic

In fiscal 1999, the Company's concerted efforts resulted in a new joint venture to explore the potential of the Jurassic formation under its growing lease block. During the 2000-2003 period, the Company, together with industry partners, made significant progress in expanding its 3-D seismic database over a much larger portion of the Maverick Basin. Blue Star Oil and Gas, Ltd. ("Blue Star"), a Dallas-based privately held exploration company, designed, executed and analyzed the results of a 3-D seismic acquisition program over the 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 426 square miles of the Maverick Basin.

Blue Star's team of geoscientists met with TXCO's exploration team to obtain the Company's expertise in interpreting the final results of the long-awaited, newly-enhanced 3-D seismic processing, as well as the identification and final ranking of multiple proposed Jurassic drilling locations on TXCO's affected acreage. Blue Star provided TXCO with a comprehensive review of the latest seismic imagery resulting from state-of-the-art processing techniques. The findings confirmed the presence and ranking of numerous drilling locations on TXCO's acreage.

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, potentially productive sands in the Jurassic and provided valuable geologic information about the formation, which should prove helpful in drilling future wells. TXCO believes that well logs indicate the likelihood of the best porosity and most attractive completion targets lie above 18,000 feet. Blue Star tested numerous horizons below 18,000 feet and only one above 18,000 feet. The zone at 16,800 feet flowed non-commercial quantities of 1,200 Btu/cf natural gas.

In February 2004, TXCO assumed operation of the well and is in process of perforating and testing the upper Jurassic intervals at 14,942 to 15,140 feet and 15,292 to 15,400 feet. TXCO began the completion attempt, utilizing a workover rig in early March 2004. Although the latest log processing results are inconclusive, TXCO engineers believe these zones may have the best porosity and represent the most attractive completion targets of the numerous Jurassic sands the well has encountered. 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. 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. The completion attempts currently planned are estimated to cost TXCO and its partners under $1 million. On March 4, 2004, the Company announced it had signed a letter of intent 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%.

By drilling the Taylor wildcat, Blue Star had 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 under the original agreement, based on information obtained from the Taylor well. Under this agreement, should the second well be drilled within one year of the removal of the existing drilling rig, Blue Star could earn an additional 25% working interest, while TXCO and its partners would be carried once again for a 25% interest at no cost. Overall, TXCO holds rights to the Jurassic on approximately 300,000 acres of its 480,000-acre Maverick Basin lease block with numerous potential locations identified by the Company's 3-D seismic studies. TXCO's 2004 drilling budget does not include expenditures for a second Jurassic well.

Williston Basin

Through 2003, the Company continued to re-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.

During 2003, the Company farmed-out a 70% WI in the Sherry #1-16 well to Luff Exploration Company ("Luff"), allowing Luff to drill and complete a horizontal lateral in the Red River B zone. The lateral was successfully completed and at year-end the well averaged 66 BOPD and 228 BWPD. In spring of 2004, Luff plans to attempt a similar completion in the TXCO Martha 1-36. TXCO retains a 30% WI and 23.7% net revenue interest ("NRI") in both wells upon successful completion of the Red River B horizon.

In mid-2003, 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 0.24% WI and 0.21% NRI in the Unit. Shortly after the formation of the Unit, 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 and are currently producing approximately 470 gross BOPD or 1 BOPD net to TXCO's interest. If these wells continue to produce at high rates, Luff plans to convert one other existing well to a water injection well. There are currently five wells producing from the Red River B zone in the Unit.

For the year ended December 31, 2003, the Company's interests produced an average of 63 net barrels of crude oil per day from 3.5 net wells. At December 31, 2003, TXCO retained approximately 87,000 net acres of its original 320,000-acre position. No funds have been included in the 2004 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. As discussed in Item 7, Contractual Obligations and Contingent Liabilities and Commitments, in January 2003 the Company entered into 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 is currently selling all of its production to the highest bidder each month, but may enter into a forward sales contract in the future, as warranted by fluctuations in gas prices.

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 2003, three purchasers of the Company's oil and gas production and other natural gas sales accounted for 39%, 20% and 18% 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 materially 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, 2003, the Company employed 45 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 newly proposed regulations, which will significantly curtail its production.

Environmental Regulation

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 net operating loss carry forwards ("NOLs") of $10.7 million that may be used to offset current taxable income. The NOLs are scheduled to expire in stages from 2008 to 2019.

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, 2003.

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

	12/31/03	12/31/02	12/31/01	12/31/00
Gas price per Mcf	$ 5.77	$ 4.90	$ 2.72	$11.04
Oil price per Bbl	$30.06	$28.71	$17.31	$25.67

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 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, 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; for the year ended December 31, 2001 the Company recorded a net loss of $50,283. 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 primarily 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.

During the fourth quarter of 2003, TXCO entered into Change in Control letter agreements with each of its employees. These agreements provide payment of two months' base pay for each year of service, to an employee if certain conditions occur, i.e. dismissal or demotion, within three years after a change of control as defined in the agreements. Payments to certain officers of TXCO are a 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 $21,700 per month with annual escalations each February 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, 2003, 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 Netherland Sewell & Associates, Inc., a Dallas, Texas, engineering firm. Estimates of proved developed oil and gas reserves attributable to the Company's interest at December 31, 2003, 2002 and 2001 are set forth in Notes to the Audited Financial Statements included in this Annual Report on Form 10-K. The PV-10 Value was determined in accordance with SEC requirements using constant prices and expenses as of the calculation date, discounted at 10% per year on a pretax basis, and is not intended to represent the current market value of the estimated oil and natural gas reserves owned by the Company.

Years Ending December 31,	PV-10 Value of Estimated Future Net Revenues
2004	$11,148,300
2005	10,161,300
2006	9,347,400
2007	6,307,400
2008	4,575,400
Thereafter	15,252,800
Total	$56,792,600

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.

	2003		2002		2001	
SEC PV-10 Reserves at December 31,	**Volumes**	**Mix ***	**Volumes**	**Mix ***	**Volumes**	**Mix ***
Natural gas (Bcf)	15.6	55%	14.7	63%	11.0	87%
Oil (MMBbls)	2.1	45%	1.5	37%	.3	13%
Natural gas equivalent (Bcfe) *	28.4	100%	23.5	100%	12.7	100%

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

Production

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,		
	2003	**2002**	**2001**
Oil:			
Production (Bbl)	454,000	314,000	50,000
Average sales price per Barrel	$28.30	$24.56	$23.55
Gas:			
Production (Mcf)	2,108,000	2,487,000	2,673,000
Average price per Mcf	$5.48	$3.35	$4.56
Average cost of production per equivalent Mcf (1)	$1.25	$1.16	$1.13

(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
12/31/03	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
12/31/01	19,870	11,140	53	39.12	96	72.47	149	111.59

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, 2003, the Company owned, by lease or in fee, the following undeveloped acres:

United States	Gross Acres	Net Acres	Estimated 2004 Delay Rentals
Texas	479,761	420,300	$ 337,431
North Dakota	88,207	84,244	171,836
South Dakota	2,637	2,130	4,114
Montana	960	960	3,840
Total	571,565	507,634	$ 517,221

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.

Gas Gathering System

During 2002, the Company acquired a gathering system to enhance its infrastructure in the Maverick Basin. The system included a 69-mile natural gas pipeline, a compressor station with three compressors and three dehydrators that currently allows 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 to Carrizo Springs, Texas, in Dimmit County and terminates at an El Paso Energy Field Services delivery point, where the gas is processed and delivered to the El Paso/GulfTerra Pipeline System. Adding this system to TXCO's Maverick Basin infrastructure gave the Company control of approximately 80 miles of pipeline in the Basin.

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

Drilling Activity

The following table sets forth the Company's drilling activity for the last three years:

	2003		2002		2001	
Activity Summary:	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Drilling Well Completions:						
Oil Wells	29	26.53	10	5.53	5	3.70
Gas Wells	19	11.14	15	11.48	18	15.53
Dry Holes	1	1.00	1	.63	6	5.00
Total Drilling Wells Completed	49	38.67	26	17.64	29	24.23
Re-entries Completed:						
Oil Wells	8	5.68	4	4.00	4	4.00
Gas Wells	0	0.00	1	1.00	36	36.00
Dry Holes	-	-	-	-	8	8.00
Total Re-entries Completed	8	5.68	5	5.00	48	48.00
Wells Completed in Year	57	44.35	31	22.64	77	72.23

	2003		2002		2001	
In-Progress Recap:	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Beginning In Progress	22	16.23	12	11.64	16	13.70
Less - Completions:						
Oil Wells	-	-	-	-	3	2.02
Gas Wells	2	0.50			9	8.17
Dry Holes	-	-	-	-	2	1.87
Less - Wells Re-entered	4	2.50	1	1.00		
Add - Spud Not Finished - New	22	16.14	11	5.59	9	9.00
- Reentries	1	1.00	-	-	1	1.00
Ending In-Progress	39	30.37	22	16.23	12	11.64

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 newly drilled wells spud 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 wells include nine CBM wells drilled in 2000 and 2001, whose completion is pending development of the coal field, 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. Of the 22 wells in progress at year-end 2002, two were completed and four were re-entered during 2003.

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.

2001 Activity: During 2001 the Company re-entered 48 (48.0 net) existing wells, of which 40 (40.0 net) wells were completed as producers in 2001, while one (1.0 net) well remained in progress at December 31, 2001, and, as mentioned above, was completed in 2002.

Included in the respective year 2001 columns are the results of the drilling activity involving 16 wells spud in the prior year and in progress at the beginning of 2001. These wells resulted in nine producing (8.17 net) gas wells and three producing (2.02 net) oil wells. In addition, two wells resulted in one (0.88 net) dry gas well and one (1.0 net) dry oil well while two (1.63 net) wells remained in progress at December 31, 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.

ITEM 3. LEGAL PROCEEDINGS

The Company is not involved in any matters of litigation incidental to its business of a significant nature.

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 4th quarter of fiscal year 2003.

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 2003	$ 6.75	$4.55
September 2003	6.24	4.04
June 2003	4.57	2.80
March 2003	3.78	2.62
December 2002	5.23	2.73
September 2002	6.89	4.62
June 2002	8.74	4.05
March 2002	4.61	1.90

As of March 5, 2004, there were approximately 1,192 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				4 Months Ended December 31	12 Months Ended August 31
	2003	2002	2001	2000	1999	1999
Operating revenues	$ 39,545,202	$ 18,958,364	$ 13,758,920	$ 14,361,357	$ 3,768,667	$ 7,235,391
Net income (loss)	40,877	(310,970)	(50,283)	6,761,935	1,188,649	931,545
Basic income (loss) per common share	0.002	(0.016)	(0.003)	0.39	0.07	0.06
Net cash provided by operating activities	15,157,692	7,389,430	8,564,022	6,529,838	3,952,602	3,858,204
Total Assets	84,206,213	53,036,319	29,843,432	29,205,641	18,647,878	17,553,815
Long-term obligations	28,908,551	7,217,231	862,177	1,195,191	1,679,936	3,094,809
Stockholders' Equity	$ 42,792,101	$ 36,970,374	$ 23,056,696	$ 23,321,736	$ 13,208,929	$ 12,020,280
Weighted average shares outstanding - Basic	20,781,223	19,080,847	17,441,242	17,242,326	15,938,516	15,668,721

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. Its long-term 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^SM under the symbol "TXCO." The Company currently has three drilling rigs under operation on its extensive 480,000-acre block in the Maverick Basin, targeting at least seven separate formations for the production of oil and natural gas, but has had as many as seven rigs operating during 2003 targeting 11 separate formations. Current emphasis is on the Georgetown formation where the Company has experienced a recent string of seven successful gas completions. The 2004 capital expenditures budget includes funds for 51 new wells (25 in the Georgetown formation) and four re-entries, as well as funds for completion of a number of wells in progress at year-end 2003 and for infrastructure improvements.

Due to the availability of many promising prospects on our Maverick Basin acreage, and higher and more stable oil and gas prices, drilling activity was substantially increased for 2003 over prior year levels. (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 increased reserves after an adequate production history is established. Additional revenues and increased credit capacity for future activity should also follow 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 a net income of $40,877 or $0.002 per basic and diluted share for the year ended December 31, 2003, compared to a net loss of $310,970 or $0.016 per basic and diluted share for the prior year. Major contributors to this improvement were higher average sales prices and increased production, both on a per Bcfe basis. Offsetting these improvements were increases in impairment, depreciation and depletion, and interest expense. These factors are discussed in the Results of Operations section.

TXCO achieved significant progress in many key areas of operations and record drilling activity during 2003. Current year results include a 186.3% drill bit reserve replacement rate and a 9.0 Bcfe increase in reserves. Including an acquisition of 0.7 Bcfe reserves, TXCO's all sources reserve replacement rate was 200.4%. Positive cash flow provided from operations totaled $15.2 million, a 105% increase over the prior year. The following table illustrates key features of the Company's continuous development over the four fiscal years presented.

Development:	**Dec-2003**	**Dec-2002**	**Dec-2001**	**Dec-2000**
No. of new oil wells completed	37	14	9	3
No. of new gas wells completed	19	16	54	6
No. of new oil wells purchased	-	94	-	-
Gas production (Mcf)	2,108,000	2,487,000	2,673,000	2,965,000
Gas reserve additions from drilling (Mcf)	8,975,000	5,103,000	8,664,000	2,126,000
Oil production (Bbl)	454,000	314,000	50,000	60,000
Oil reserves additions from drilling (Bbl)	1,330,000	600,000	66,000	5,000
Gas equivalent production (Bcfe)	4.83	4.37	2.97	3.33
Reserve additions (Bcfe)				
Drilling	16.96	8.70	9.06	2.16
Revisions of previous estimates	(7.95)	2.44	1.02	.41
Purchased	0.68	4.04	-	-
Total reserves added (Bcfe)(1)	9.69	15.18	10.08	2.57
Reserve replacement rate				
Drill bit	186%	255%	339%	77%
Drill bit plus purchases (all sources)	200%	347%	339%	77%
Non-developed Texas acreage leased	479,761	408,992	372,000	365,000
Non-developed Williston Basin acreage leased	91,804	91,804	105,000	302,000

(1) Reserve make-up at year-end 2003: 55% gas, 45% proved developed

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 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 increased oil and gas 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, compared with a borrowing base of $12 million, with borrowings of $5.8 million, and unused borrowing capacity of $6.2 million at December 31, 2002. Interest is payable monthly, with principal due at maturity in March 2006. Proceeds are used for the acquisition and development of oil and gas properties and general corporate working capital purposes. The Facility provides the lender with semiannual scheduled redeterminations, at mid-year and each subsequent anniversary date, while providing for two unscheduled redeterminations per year, at the Company's discretion. Borrowings under the Facility are secured by a first-priority mortgage covering the Company's working and other interests in the majority of its oil and gas leases. The Facility also provides the lender with a commitment fee equal to 0.5% per annum on the unused borrowing base.

The Facility contains certain financial covenants and other negative restrictions common for a financing of this type. At December 31, 2003, the Company was not in compliance with the Current Ratio covenant. The Company received a waiver related to this covenant for the December 31, 2003 and March 31, 2004 reporting periods, and expects to be in compliance with the covenant at June 30, 2004 and subsequent periods. Accordingly, the Credit Facility is classified as long-term.

The interest rate under the Facility, during 2002 and 2003, was based on the Wall Street Journal Prime Rate plus applicable margin ("base rate"). A Eurodollar Rate plus applicable margin may be utilized at the election of the Company. The interest rate at December 31, 2003, was 4.0%. The agreement was amended effective December 31, 2003, to provide for two tranches with separate repayment terms and interest rates. Tranche A has similar interest terms to the original agreement, with lower applicable margins on the Eurodollar Rate option, and applies to the first $12.5 million of borrowings. Tranche B will apply to borrowings above $12.5 million and bear interest at the Eurodollar Rate plus 400 basis points. Any borrowings then outstanding under Tranche B will be payable on January 1, 2005. At March 5, 2004, the outstanding balance was $12.95 million and the unused borrowing base was $1.05 million. The rates in effect at March 5, 2004, were 4.0% on $12.5 million of borrowings, and 5.1% on the excess over $12.5 million.

2004 Capital Requirements Outlook

Overall: Management believes that the Company's positive cash flow from existing production and anticipated production increases from new drilling, along with the Credit Facility, will provide adequate capital to fund operating cash requirements and complete its scheduled exploration and development goals as targeted by its capital expenditure program for 2004. The Company expects it will be able to further increase its borrowing base commensurate with the expected additional growth of its proved oil and gas reserves throughout the base term of the Facility.

While management believes it has identified sufficient sources of working capital to fund its planned activities through the end of the coming year, there is no assurance that energy prices or other market factors will remain favorable. Should 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 2004, include the following:

***Maverick Basin Activity*:** Initial capital expenditures of $23.4 million planned for 2004 target the Company's Maverick Basin core properties. The primary component of these expenditures is $21 million for drilling wells. Over $2.4 million is earmarked for seismic, leasehold, and gas gathering system 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 55 wells, including 25 Georgetown gas wells, 12 Glen Rose porosity zone oil wells, 10 San Miguel waterflood oil wells, and eight Glen Rose horizontal shoal or reef gas wells. 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 2004 wells:

	Typical Gross Well Costs	
	Dry Hole	**Completed**
Glen Rose oil porosity zone horizontal well	$650,000	$925,000
Glen Rose shoal horizontal gas well	690,000	850,000
Glen Rose reef vertical gas well	250,000	500,000
Georgetown gas well - southern	630,000	785,000
Georgetown gas well - northern	500,000	670,000
San Miguel waterflood oil well	100,000	240,000

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 2004 delay rentals of $179,800. TXCO will continue in its efforts to offer remaining acreage, seismic data, and identified prospects to other industry operators. TXCO participated in two farm-outs during 2003 and anticipates additional activity during 2004.

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 58% 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 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, excluding $5.0 million paid and later reborrowed on its Credit Facility, on its long-term debt obligations during 2003, while payments of interest totaled $1.2 million.

As a result of these activities, the Company ended the year 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.

The Credit Facility was amended during 2003 to modify the current ratio covenant and waive the violation at June 30, 2003 (Second Amendment), as well as, extend the maturity date to March 2006 and provide for two Tranches (Third Amendment). The Company also received a permanent waiver for the March 31, 2003 violation of the current ratio covenant. Copies of these amendments are filed as exhibits to this document.

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, a second installment of $1.4 million was made. A final installment of $1.4 million is due in January 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. During the third quarter, the Partnership began construction of 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 the year 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 on page F-4 and the Production discussion on page 15.

Change in Selected Items:	2003 vs. 2002	2002 vs. 2001	2001 vs. 2000
Operating revenues	+ 108.6%	+ 37.8%	- 4.2%
Lease operations expense	+ 8.0	+ 69.6	+ 108.0
Impairment & abandonments	+ 102.4	- 53.0	- 15.2
Depreciation, depletion & amortization	+ 32.7	+ 103.0	+ 18.1
Net income (loss)	+ 113.1	- 518.4	- 100.7
Basic income (loss) per common share	+ 112.5	- 433.3	- 100.8
Oil production (Bbl)	+ 44.4	+ 528.0	- 16.7
Gas production (Mcf)	- 15.2	- 7.0	- 9.8
Oil average sales price per Bbl	+ 15.2	+ 4.3	- 15.4
Gas average sales price per Mcf	+ 63.5	- 26.5	+ 11.2

2003 Compared to 2002

The Company reported a net income of $40,877 or $0.002 per basic and diluted share for the year ended December 31, 2003, compared to a net loss of $310,970 or $0.016 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 is 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. The Vivian 1-687 began producing in October and had produced 1,866 BO and 220,883 Mcf of gas by year-end. The Kothman 1-673 produced 170 BO and 10,986 Mcf of gas in its seven days of operation in 2003. The Myers 1-684 began production on December 31 at a rate of 3,100 Mcfd. Included in the number of gas wells classified as producing at December 31, 2003, were 38 CBM gas wells, which are still in their initial dewatering stage, and are not yet contributing a significant amount of new gas production. 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 have been and 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. The Company hopes to reverse the declining natural gas production rates based on its year 2004 drilling success to date, fourth quarter 2003 Georgetown wells and expected results from ongoing drilling projects. At February 29, 2004, average daily net production included 7.0 MMcf of natural gas and 1,000 barrels of oil.

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 is 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.

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 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, have not established 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 is the first full year of depreciation on the pipeline and well service equipment acquired in mid-2002.

The Company's gas gathering system is generally expected to operate on a break-even basis. The gas is sold at several points along the system with a significant portion being delivered to purchasers through the El Paso/Gulf Terra Pipeline System ("El Paso"). The gas delivered through El Paso is processed by El Paso to remove natural gas liquids, which are marketed separately by El Paso. The Company receives a share of the revenues for these liquids. Natural gas pricing fluctuations are reflected at the wellhead for the Company's operated gas properties. Due to the acquisition of the Company's primary gas gathering assets in May of 2002, comparisons of 2003 to 2002 are not meaningful. During the current year, the Company's gas gathering system revenues rose $12.6 million, while expense rose $12.5 million. Costs to purchase third-party gas along the Company's gathering system totaled $14.0 million, while associated transportation and marketing expenses required to market that gas were $369,000 and direct operating costs of the pipeline were $749,000. Sharply higher gas prices in late February 2003, combined with an erroneous gas nomination earlier that month, resulted in a one time trading loss of approximately $316,000 in the first quarter. Management has determined the trading loss was an isolated incident and has refined its internal procedures to prevent a similar reoccurrence.

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. These particular costs are likely to increase significantly in 2004.

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 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.

2002 Compared to 2001

The Company reported a net loss of $310,970 or $0.016 per basic and diluted share for the year ended December 31, 2002, compared to a net loss of $50,283 or $0.003 per basic and diluted share for the prior year.

Revenues for 2002 increased by 38% compared to 2001. Oil production increased by 528% while natural gas production declined by 7% as compared with the prior year. The increase in oil production is due to the new Comanche lease oil wells, along with production from the May 2002 acquisition of the Pena Creek field. The decline in 2002 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 new gas production from the 16 new gas wells drilled and completed during the year. Included in the number of gas wells classified as producing at December 31, 2002, were 38 CBM gas wells, which are still in their initial dewatering stage, and are not yet contributing a significant amount of new gas production. On an equivalent-unit basis, prices averaged 18% lower in 2002 as compared to 2001. Crude oil prices averaged 4% higher while natural gas prices fell 27%. Average lower prices for 2002, as compared to 2001, had a $3.6 million negative impact on revenues in 2002. Commodity prices have been and continue to be volatile. During 2001, realized gas prices ranged from a high of $10.50 per Mcf in January to a low of $1.26 per Mcf in October. During 2002 realized natural gas prices ranged from a high of $4.71 per Mcf in November to a low of $1.75 per Mcf in February. During the first three months of 2003 crude oil and natural gas prices have increased significantly. Average daily net gas production rates in 2002 decreased to 6.8 MMcf, a 7% decline from the prior year, while average daily net oil production rates in 2002 increased to 860 Bbls, a 528% over the prior year.

Lease operating expense for 2002 increased $1.7 million, from $2.4 million in 2001 to $4.1 million in 2002, a 70% increase. This increase is primarily due to the addition of 16 new natural gas wells and 14 new oil wells during 2002 and the acquisition of 188 active Pena Creek wells. 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 2002 to the Company's existing lease operating expense levels. Operating expense per Mcfe increased $0.03, from $1.13 in 2001 to $1.16 in 2002. The increase in the rate is due to the Pena Creek field, which consists of three waterflood units. Typically, waterfloods incur higher costs of operations. Excluding the Pena Creek field, operating expense per Mcfe for 2002 is $1.07, a decrease of $0.06 from the prior year. Also, included in operating costs is the cost of operating the CBM wells. These costs totaled $583,852 in 2002 and $446,006 in 2001. 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 $0.91 in 2002 and $0.99 in 2001.

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 53% primarily due to lower impairment rates on non-producing acreage in the Williston Basin during 2002 versus 2001. Depreciation, depletion and amortization increased by almost $2.9 million, or 123%, over 2001 due primarily to the increased number of producing wells being depleted for wells added through the drill bit and the Pena Creek acquisition. The increase in depreciation was due to increased investments in other equipment including the pipeline and well service equipment acquisitions. The increase in amortization was primarily due to the full year amortization related to the 3-D seismic survey on the Comanche lease acquired during 2001.

General and administrative costs remained at approximately 10.7% of revenues, while increasing 37% compared to 2001 reflecting the higher sustained level of Company operations. The increase is due primarily to higher salaries, wages and benefits associated with staff increases including six engineering and administrative staff additions and eight new field personnel during 2002. Also contributing to the increase were higher costs for property and liability insurance and increased investor relations expenses.

The 75% decrease in interest income reflects the declining cash levels in interest bearing accounts and declining interest rates during 2002 versus 2001. Interest expense increased by $144,840 in 2002 from 2001 due to higher debt levels.

CONTRACTUAL OBLIGATIONS AND CONTINGENT LIABILITIES AND COMMITMENTS

The following is a summary of the Company's future payments on obligations as of December 31, 2003.

	Payments Due by Period				
Contractual Obligations	**1 Year**	**2-3 Years**	**4-5 Years**	**After 5 Years**	**Total**
Long-term debt	$ 1,752,286	$ 15,425,598	$ -	$ -	$ 17,177,884
Redeemable preferred stock	-	-	-	16,000,000	16,000,000
Operating lease obligations	316,000	613,000	179,000	-	1,108,000
Total Contractual Cash Obligations	$ 2,068,286	$ 16,038,598	$ 179,000	$ 16,000,000	$ 34,285,884

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. 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 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 if and when the well is determined not to have found reserves in commercial quantities. The sale of a partial interest in a proved property is accounted for as a cost recovery and no gain or loss is recognized.

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 Netherland Sewell & Associates, a Dallas-based 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 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 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, 2003, and 2002. Based on the Company's projected profitability, a valuation allowance was recorded of approximately $3.0 million and $2.8 million at December 31, 2003 and 2002, respectively, 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 Financial Statements has been recorded as a liability as a result of this Statement.

The FASB and representatives of the accounting staff of the Securities and Exchange Commission are currently engaged in discussions regarding the application of certain provisions of SFAS No. 141, "Business Combinations," and SFAS No. 142, "Goodwill and Other Intangible Assets," to companies in the extractive industries, including oil and gas companies. The FASB and the SEC staff are considering whether the provisions of SFAS No. 141 and SFAS No.142 require registrants to classify costs associated with mineral rights, including both proved and unproved lease acquisition costs, as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures.

Historically, the Company has included oil and gas lease acquisition bonus payments as a component of oil and gas properties. In the event the FASB and SEC staff determine that costs associated with mineral rights are required to be classified as intangible assets, a portion of the Company's oil and gas property acquisition costs may be required to be separately classified on its balance sheets as intangible assets or further described in footnote disclosures. However, the Company currently believes that its results of operations and financial condition would not be materially affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with existing successful efforts accounting rules and impairment standards. The Company does not believe the classification of oil and gas lease acquisition costs as intangible assets would have any impact on the Company's compliance with covenants under its debt agreements.

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 is in place for 2004. A 10% fluctuation in the price received for oil and gas production would have an approximate $2.4 million impact on the Company's annual revenues based on 2003 sales volumes.

Interest Rate Risk**:** The Company has borrowed funds under its Revolving Credit Facility with Hibernia National Bank, with interest tied to the Wall Street Journal Prime rate. At March 5, 2004, the Company had $12.95 million in total borrowings under the Facility, with interest at 4.00% on $12.5 million, and 5.1% on borrowings in excess of the $12.5 million base. Under terms of the Facility, the Company has the option to lock in a fixed interest rate for a period of up to six months using LIBOR rates plus an applicable margin. Should interest rates start to rise, the Company can convert its outstanding loan balance to the LIBOR option rate within three days of its election. An annualized 10% fluctuation in interest charged on the outstanding balance at March 5, 2004, would have an approximate $50,000 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 DISCLOSURES

None

ITEM 9A. CONTROLS AND PROCEDURES

The Company's Chief Executive Officer and the Chief Financial Officer have carried out an evaluation of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to Exchange Act Rule 13a-14 and Rule 15d-14. Based upon that evaluation, which took place as of a date within 90 days of the filing of this report, the Company's Chief Executive Officer along with the Chief Financial Officer concluded that the Company's disclosure controls and procedures are effective in timely alerting them to material information relating to the Company (including its consolidated subsidiaries) required to be included in reports it files with the SEC.

There have been no significant changes in the Company's internal controls or in other factors that could significantly affect internal controls subsequent to the date of the above evaluation.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth certain information regarding the directors and executive officers of the Company, as of March 5, 2004:

Name	Class	Position	Age
Stephen M. Gose, Jr.	B	Chairman of the Board of Directors Chairman Compensation Committee, and Member Nominations Committee	74
Michael J. Pint	C	Director, Chairman Audit Committee (Financial Expert) Member Compensation and Nominations Committees	60
Robert L. Foree, Jr.	A	Director, Chairman Nominations Committee Member Audit and Compensation Committees	74
Alan L. Edgar	B	Director, Member Compensation and Nominations Committees	58
Thomas H. Gose	A	Director and Member Nominations and Audit Committees	48
Charles W. Yates, III	D	Director	35
James E. Sigmon	C	President, Chief Executive Officer and Director	55
James J. Bookout		Chief Operating Officer and Vice President	42
P. Mark Stark		Chief Financial Officer and Vice President-Finance	49
Roberto R. Thomae		Secretary/Treasurer and Vice President-Capital Markets	53
Richard A. Sartor		Controller	51

Stephen M. Gose, Jr., has served as Chairman of the Board of Directors of the Company since July 1984. He has been a member of the Compensation Committees since June 1997 and served as its Chairman through April 1998 and was renamed as Chairman in February 2004. Mr. Gose was a member of the Audit Committee from June 1997 through May 2001 and served as its Chairman from June 1997 through April 1998. He has been a member of the Nominations Committee since its inception in May 2001. Mr. Gose served as a Director of the Company's former subsidiary, ExproFuels, Inc. from 1994 through 1999. A geologist by training, he has been active for more than 46 years in exploration and development of oil and gas properties, in real estate development, and in ranching through the operations of Retamco Operating, Inc., its predecessors and affiliates.

Michael J. Pint has served as a Director since May 1997. He has been a member of the Audit Committee of the Board of Directors since June 1997 and has served as its Chairman since April 1998. Mr. Pint also serves as the Audit Committee Financial Expert, as defined by the SEC. Mr. Pint has been a member of the Compensation Committee since June 1997 and served as its Chairman from April 1998 through May 2001. He has been a member of the Nominations Committee since its inception in May 2001. Mr. Pint has more than 36 years banking experience, serving in the bank regulatory arena as well as in the capacity of chairman, president and director of 40 different banks and bank holding companies throughout the country. Previous bank regulatory and management positions include a four-year term as Commissioner of Banks and Chairman of the Minnesota Commerce Commission from 1979 to 1983 and Senior Vice-President and Chief Financial Officer of the Federal Reserve Bank of Minneapolis, Minnesota through 1983.

Robert L. Foree, Jr. has served as a Director since May 1997 and as a member of the Audit and Compensation Committees of the Board of Directors since June 1997. He has been a member of the Nominations Committee and served as its Chairman since its inception in May 2001. A geologist by training, he has been active for more than 46 years in the exploration and development of oil and gas properties. Since 1992, Mr. Foree has served as President of Foree Oil Company, a privately held Dallas, Texas based independent oil and gas exploration and production company.

Alan L. Edgar has served as a Director of the Company since May 2000 and as a member of the Compensation Committee of the Board of Directors since that time. He served as the Chairman of the Compensation Committee from May 2001 until February 2004. Mr. Edgar served as a member of the Audit Committee from May 2000 through February 2004. He has been a member of the Nominations Committee since its inception in May 2001. He has been involved in energy related investment banking and equity analysis for over 30 years. Since 1998, Mr. Edgar has served as President of Cochise Capital, Inc. a privately held Dallas, Texas based company specializing in exploration and production related mergers and acquisitions advisory and financing. Previous investment banking and energy financing experience includes serving as Managing Director and Co-Head of the Energy Group of Donaldson, Lufkin & Jenrette Securities, Inc., from 1990 to 1997, serving as Managing Director of the Energy Group of Prudential-Bache Capital Funding from 1987 to 1990 and serving as Corporate and Research Director of Schneider, Bernet & Hickman, Inc. (Thompson, McKinnon) from 1972 through 1986. Due to the new Nasdaq independence standards issued in November 2003, Mr. Edgar is no longer considered independent and, therefore, tendered his resignation from the Audit Committee and as Chairman of the Compensation committee. He is working with the Company to assure an orderly transition.

Thomas H. Gose has served as a Director of the Company since February 1989, as Secretary from 1992 through March 1997 and as Assistant Secretary from March 1997 until August 2002. He had been a member of the Nominations Committee since May 2001. Mr. Gose served as a member of the Audit Committee from May 2001 until 2002, and rejoined the Committee in February 2004. Mr. Gose served as President and Director of the Company's former subsidiary ExproFuels, Inc. from 1994 through 1999. Since October 2000 he has served as President of NEOgas, Inc., a Houston based subsidiary of NEOppg International Ltd. NEOgas develops and markets technologies to transport and deliver compressed natural gas to markets with stranded gas production or stranded customer bases. He formerly served as Director, CEO and President of Retamco Operating, Inc., (a large shareholder of the Company) its predecessors and affiliates from 1987 to 1999. Thomas H. Gose is the son of Stephen M. Gose, Jr.

Mr. Charles W. Yates, III has served as a Director since August 2003. Mr. Yates joined Kayne Anderson Capital Advisors ("Kayne Anderson") in March 2001, where he is a Managing Director and is responsible for the origination and execution of private equity transactions in the energy industry. Previously, Mr. Yates joined Stephens, Inc., an integrated merchant and investment bank, in June 1994 where his final position was Senior Vice President and head of the Power Technology Group. A member of Phi Beta Kappa, Mr. Yates received his Bachelor of Arts, magna cum laude in 1991 and his Master of Business Administration in 1994 from Rice University. Mr. Yates also serves on the Board of Directors for Cannon Energy, Inc.

James E. Sigmon has served as the Company's President since February 1985. He has been a Director of the Company since July 1984. He served as a Director of ExproFuels, Inc. through November 1998. Mr. Sigmon has been active for 31 years in the exploration and development of oil and gas properties. Prior to joining the Company, Mr. Sigmon served in the management of a private oil and gas exploration company active in drilling oil and gas wells in South Texas. Mr. Sigmon received his Bachelor of Science degree in electrical engineering from the University of Texas at Arlington in 1971.

James J. "Jeff" Bookout, P.E., was named Vice President and Chief Operating Officer, a new position, in June 2003. He now directs all of the Company's exploration, drilling and production functions. He has some 20 years of experience in exploration and production operations, serving in operations positions with such firms as Pioneer Natural Resources USA, Inc. (NYSE:PXD), Abraxas Petroleum Corp. (AMEX:ABP) as Senior Operations Engineer from 1997 until moving to Networkinternational as Engineering/Marketing Manager in 1999, and Venus Exploration, Inc. (OTC:VENX.PK) as Operations Manager from 2001 until joining TXCO in 2002 as Operations Manager. He received a Bachelor of Science degree in petroleum engineering from Texas A&M University in 1984.

P. Mark Stark joined TXCO in June 2003 as Vice President, Treasurer and Chief Financial Officer. He now oversees the Company's accounting, finance and treasury functions. Mr. Stark has more than 25 years of corporate financial experience with an emphasis in the natural resources and agribusiness industries. From 1995 through 1998, Mr. Stark served as Chief Financial Officer for Dawson Production Services Inc. (NYSE:DPS) an oil field service company. From 1998 through 2000 he served as the CFO for Alamo Water Refiners, Inc., a privately held manufacturing and distribution company. Between, 2000 and 2002 Mr. Stark served as the Chief Financial Officer for Venus Exploration, Inc., a publicly held exploration company. Prior to joining TXCO, Mr. Stark provided financial consulting and advisory services to a privately held distribution company. He received a Bachelor of Business Administration degree from the University of Texas at Austin in 1977 and a Master of Business Administration degree from Southern Methodist University in 1978.

Roberto R. Thomae was named Vice President of Capital Markets in June 2003 with responsibilities for the Company's financial markets and investment community contacts, investor relations and corporate communications. He continues to serve as Secretary since March 1997. He served as Chief Financial Officer, Treasurer and Vice President-Finance of the Company from September 1996 through June 2003. From September 1995 through September 1996, he was a consultant to the Company in a financial management capacity. From 1989 through 1995 Mr. Thomae was self-employed as a management consultant primarily involved in the development of domestic and international oil and gas exploration projects and the marketing of refined products. Mr. Thomae received a Bachelor of Business Administration degree, with honors, from the University of Texas at Austin in 1974.

Richard A. Sartor has served as Controller of the Company since April 1997. A Certified Public Accountant since 1980, Mr. Sartor owned his own private accounting practice from 1989 through March 1997. Mr. Sartor received a Bachelor of Business Administration degree from the University of Texas at Austin in 1974 and a Master of Business Administration from the University of Texas at San Antonio in 1990.

Each of the Directors has been elected by the shareholders to serve until his successor is duly elected. In May 2001, the shareholders of the Company approved the adoption of a classified board. The board is structured with three classes of directors, Classes A, B and C, each having two directors with current terms expiring in the years 2005, 2003 and 2004, respectively. Directors elected at the May 2002 annual meeting and later meetings serve full three-year terms. Charles W. Yates, III serves on TXCO's Board of Directors as Kayne Anderson's representative until the Preferred Stock, Series B, is redeemed.

Code of Conduct: The Company is currently modifying its Code of Conduct ("Code") applicable to all employees to conform to the requirements issued in November 2003 by the Nasdaq Stock Market[SM] under rule 4350(n). The revised Code will be filed prior to the annual meeting of shareholders that will be held on May 14, 2004. Exhibit 14, filed with this document, contains TXCO's "Code of Ethical Conduct for Senior Officers and Financial Managers," which satisfies the requirements of Item 406 of Regulation S-K and is currently in effect.

ITEM 11. EXECUTIVE COMPENSATION

Summary Compensation Information: The following table contains certain information for the past three years with respect to the chief executive officer and those executive officers of the Company with total annual salary and bonuses exceeding $100,000:

SUMMARY COMPENSATION TABLE

	Year Ended	Salary	Bonus	Other Annual Compensation	All Other Compensation
James E. Sigmon	12/31/03	$210,000	$8,750	(1) $434,820	$671
President & CEO	12/31/02	204,697	8,750	(1) 265,354	393
	12/31/01	201,250	8,750	(1) 210,099	592
Roberto R. Thomae	12/31/03	150,000	6,250	-0-	235
VP - Capital Markets &	12/31/02	126,669	5,625	-0-	177
Corporate Secretary	12/31/01	111,250	4,792	-0-	237
James J. Bookout	12/31/03	109,463	4,750	-0-	77
VP & COO	12/31/02	69,251	4,000	-0-	28
Richard A. Sartor	12/31/03	100,200	4,175	-0-	141
Controller	12/31/02	88,051	3,875	-0-	102
	12/31/01	76,946	3,375	-0-	147

(1) Represents income from overriding royalty interests in Company oil and gas properties.

OPTION GRANTS IN LAST FISCAL YEAR

Name	# Options Granted	% of Total Options Granted to Employees In Fiscal Year	Exercise Price per share	Expiration Date	Grant Date Value (1)
James E. Sigmon	None	N/A	N/A	N/A	N/A
President & CEO					
P. Mark Stark	25,000	17.24	4.38	06/20/2013	$1.46
VP-Finance & CFO					
James J. Bookout	25,000	17.24	4.38	06/20/2013	$1.46
VP & COO					
Roberto R. Thomae	None	N/A	N/A	N/A	N/A
VP - Capital Markets & Corporate Secretary					
Richard A. Sartor	10,000	6.90	4.38	06/20/2013	$1.46
Controller					

(1) The fair value for all options granted, whether vested or not, was estimated at the date of grant using the Black-Scholes option pricing model with the following weighted-average assumption: risk-free interest rate of 3.12%; dividend yield of 0%; volatility factors of the expected market price of the Company's common stock of 90% and a weighted-average expected life of the option of three years.

AGGREGATED OPTION ACTIVITY IN LAST FISCAL YEAR

Name	# Shares Exercised	Value Realized	Number of Unexercised Options/SARs		Value of Unexercised Options/SARs	
			Exercisable	Unexercisable	Exercisable	Unexercisable (1)
James E. Sigmon(2)	N/A	N/A	400,000	300,000	$1,527,500	$1,192,500
P. Mark Stark	N/A	N/A	N/A	25,000	N/A	43,000
James J. Bookout	N/A	N/A	N/A	25,000	N/A	43,000
Roberto R. Thomae	N/A	N/A	175,000	N/A	657,750	N/A
Richard A. Sartor	N/A	N/A	50,000	10,000	177,875	17,200

(1) Value of unexercised options calculated as the difference in the stock price at period end and the option price.

(2) 400,000 of Mr. Sigmon's unexercised options were exercisable as of December 31, 2003, and the remaining 300,000 options vest and are exercisable in specified amounts upon the Company's common stock attaining the following price levels: 100,000 shares at $10.00; 100,000 shares at $12.50 and 100,000 shares at $15.00.

COMPENSATION OF DIRECTORS

Members of the Board of Directors who serve as Executive Officers of the Company are not compensated for any services provided as a Director. Outside (non-employee) directors of the Company are paid an annual retainer of $15,000 per year upon election to the Board. Additionally, the outside directors are paid a fee of $1,000 plus reimbursement of related travel expenses for each board meeting attended. The chairman of the audit committee and the chairman of the compensation committee receive an additional $10,000 per year. Beginning in 1997, upon assuming Director status, new outside directors have been awarded 10-year options (Directors Options) for the purchase of 75,000 shares of Company common stock at 110% of the stock's market value on the date of grant, with such options vesting in equal annual increments over their first three years of service.

EMPLOYMENT CONTRACTS

The Company has an employment agreement with its president, Mr. James E. Sigmon, which sets his salary at a minimum of $210,000 annually, and includes the grant of a non-cancelable overriding royalty interest equal to 1% of the Company's working interest, proportionately reduced, under all leases the Company has or acquires during his term as President. The agreement is cancelable with 90 days notice by the Company but his right to the overriding royalty interest is vested and cannot be terminated.

COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

No Compensation Committee interlocks existed during the Company's last completed year. The Compensation Committee of the Board of Directors of the Company was established in June 1997 and currently consists of Alan L. Edgar, Robert L. Foree, Jr., Michael J. Pint, and Stephen M. Gose, Jr. The principal function of the Committee is to approve the compensation of all executive officers of the Company, to recommend to the Board the terms of principal compensation plans requiring stockholder approval and to direct the administration of the Company's 1995 Flexible Incentive Plan. Subsequent to year-end, Mr. Edgar received a fee pursuant to an investment banking advisory agreement. See Item 13 for more information. Stephen M. Gose, Jr. replaced Alan L. Edgar as Chairman of the Compensation Committee in February 2004.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following tables set forth beneficial ownership of the Company's common stock, its only class of equity security. The percent owned is based on 23,381,145 shares outstanding and 25,392,478 fully diluted shares, which includes 2,011,333 shares under options and warrants as of March 1, 2004.

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS

The following table sets forth information concerning all persons known to the Company to beneficially own 5% or more if its common stock, including information filed pursuant to Rule 13d filings made available to the Company during the year.

Name and Address of Beneficial Owner		Number of Shares Beneficially Owned	Percent Owned
Stephen M. Gose, Jr.	(1)	1,542,877	6.58%
HCR Box 1010 Hwy 212			
Roberts, Montana 59070			
Kayne Anderson Energy Fund II, L.P.		1,866,666	7.98%
1100 Louisiana, Ste. 4550			
Houston, TX 77002			
Tahoe Invest		1,200,000	5.13%
Innere Guterstrasse 4			
6304 Zug			
Switzerland			

(1) Please see related footnotes presented in the Security Ownership of Management table that follows.

SECURITY OWNERSHIP OF MANAGEMENT

The following table sets forth the number of shares of common stock beneficially owned as of March 5, 2004, by each director, each executive officer named in the Summary Compensation Table and by all directors and executive officers as a group. Information provided is based on Forms 3, 4, 5, stock records of the Company and the Company's transfer agent.

Name		**Number of Shares Beneficially Owned**	**Percent Owned (1)**
Stephen M. Gose, Jr.	(3) (7)	1,542,877	6.58%
Thomas H. Gose	(7) (8)	849,601	3.63%
James E. Sigmon	(2)	774,400	3.22%
Michael Pint	(4)	325,000	1.39%
Alan L. Edgar	(5)	303,433	1.29%
Robert L. Foree, Jr.	(4)	99,100	.42%
Charles W. Yates, III	(10)	1,866,666	7.98%
James J. Bookout	(9)	-	-
P. Mark Stark	(9)	-	-
Roberto R. Thomae	(6)	175,000	0.74%
Richard A. Sartor	(6)	50,000	0.21%
All Directors and Executive Officers as a group		5,986,077	24.12%

(1) Except as otherwise noted, the Company believes that each named individual has sole voting and investment power over the shares beneficially owned.

(2) The number of shares beneficially owned by Mr. Sigmon includes 74,400 shares owned directly and 700,000 shares of the Company's Common Stock reserved for issuance through options issued under the Company's 1995 Flexible Incentive Plan.

(3) The number of shares beneficially owned by Mr. Stephen M. Gose, Jr. include his 100% interest, shared equally with his spouse, in 1,467,877 shares owned by Retamco Operating, Inc.

(4) The number of shares beneficially owned by Mr. Pint and Mr. Foree each includes 75,000 shares of the Company's Common Stock reserved for issuance under non-qualified options issued to outside directors of the Company exercisable at March 5, 2004 plus 250,000 and 24,100 respectively, of directly owned shares.

(5) The number of shares beneficially owned by Mr. Edgar includes 95,100 shares owned directly, 133,333 shares of the Company's Common Stock reserved for issuance under five-year warrants granted in February 2000, for investment banking services rendered prior to his election as a director and 75,000 shares reserved for issuance under non-qualified options issued to outside directors of the Company exercisable at March 5, 2004.

(6) The total number of shares beneficially owned by Mr. Thomae and Mr. Sartor represent shares of the Company's Common Stock reserved for issuance through options issued under the Company's 1995 Flexible Incentive Plan.

(7) The number of shares beneficially owned by Mr. Stephen M. Gose, Jr. and Mr. Thomas H. Gose each includes 75,000 shares of the Company's common stock reserved for issuance under non-qualified options issued to outside directors of the Company exercisable at March 5, 2004.

(8) The number of shares beneficially owned by Mr. Thomas Gose includes 774,601 shares owned directly.

(9) Mr. Bookout and Mr. Stark have no ownership position at this time. Both have 25,000 shares in stock options that are not yet exercisable.

(10) Mr. Yates is considered a beneficial owner of the shares held by his employer, Kayne Anderson. He does not have voting and investment power over these shares.

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	Weighted-average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (excluding securities reflected in column (a)
	(a)	(b)	(c)
Equity compensation plans approved by security holders	1,683,000	$ 2.78	393,305
Equity compensation plans not approved by security holders	N/A	N/A	N/A
Total	1,683,000	$ 2.78	393,305

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Subsequent to year-end, certain investors exercised their warrants to purchase a total of 1,238,096 shares of the Company's Common Stock at $3.00 per share. Pursuant to the terms of his investment banking advisory agreement entered into in 2000, upon closing of the sale Mr. Alan Edgar received an advisory fee totaling $223,000. Mr. Edgar is a member of our Board of Directors.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Audit Fees: Fees paid to Akin, Doherty, Klein & Feuge ("ADKF"), as our independent auditors during the years ended December 31, 2003 and 2002, were $62,950 and $44,550, respectively, for its independent audit of our annual financial statements, and review of the financial statements contained in our quarterly reports on Form 10-Q.

Audit-Related Fees: Fees paid to ADKF were $12,475 and $10,600 for the years ended December 2003 and 2002, respectively, for its review of information related to stock offerings, registration statements and new accounting pronouncements.

Tax Fees: Fees paid to ADKF were $15,700 and $6,275 for the years ended December 2003 and 2002, respectively, for its professional services related to federal and state tax compliance, tax advice and tax planning.

All Other Fees: Fees paid to ADKF were $800 and $1,050 for the years ended December 2003 and 2002, respectively, for its professional services related to research on proposed transactions, and miscellaneous other immaterial items.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(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:
Independent Auditors' Reports.
Balance Sheets, December 31, 2003 and December 31, 2002.
Statements of Operations, Years Ended December 31, 2003, 2002 and 2001.
Statements of Stockholders' Equity, Years Ended December 31, 2003, 2002 and 2001.
Statements of Cash Flows, Years Ended December 31, 2003, 2002 and 2001.
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:

** 3.1	Articles of Incorporation of the Registrant filed as Exhibit 3(B) to the registration statement on Form S-1; Reg. No. 2-65661.
** 3.2	Articles of Amendment to Articles of Incorporation of The Exploration Company, dated July 27, 1984, filed as Exhibit 3.2 to Registrant's Annual report on Form 10-K, dated February 4, 1985.
** 3.3	Articles of Amendment to the Articles of Incorporation of the Exploration Company dated April 2, 1985.
** 3.4	By-Laws of the Registrant filed as Exhibit 5(A) to the Registration Statement on Form S-1; Reg. 2-65661.
** 3.5	Amendment to By-Laws of registrant, dated September 1, 1985.
** 3.6	Articles of Amendment to the Articles of Incorporation of The Exploration Company dated April 6, 1990.
** 4.1	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.
** 4.2	Certificate of Designation of Redeemable Preferred Stock, Series B of The Exploration Company of Delaware, Inc.
** 4.3	Rights Agreement, between the Registrant and Kayne Anderson Energy Fund II, L.P. and Gryphon Master Fund, L.P.
** 4.4	Amendment to Subscription Agreement, dated August 5, 2003.
** 10.2	Employment Agreement between the Registrant and James E. Sigmon dated October 1, 1984.
** 10.3	Registrant's Amended and Restated 1983 Incentive Stock Option Plan filed as Exhibit A to registrant's definitive Proxy Statement, dated February 20, 1985.
** 10.4	Registrant's 1995 Flexible Incentive Plan, filed as Exhibit A to registrant's definitive Proxy Statement, dated April 28, 1995.
** 10.5	Registrant's Form S-8 Registration Statement for its 1995 Flexible Incentive Plan, dated November 26, 1996.
** 10.6	Registrant's Amendment to its 1995 Flexible Incentive Plan, filed as Proposal II of the registrants definitive Proxy Statement, dated January 12, 1999.
** 10.7	Registrant's Plan and Agreement of Merger of The Exploration Company with and into The Exploration Company of Delaware, Inc., filed as Appendix A of the registrants definitive Proxy Statement, dated January 12, 1999.
** 10.8	Registrant's Certificate of Incorporation of The Exploration Company of Delaware, Inc., filed as Appendix B of the registrant's definitive Proxy Statement, dated January 12, 1999.
** 10.9	Registrant's Certificate of Amendment of Certificate of Incorporation of The Exploration Company of Delaware, Inc., filed as Appendix C of the registrant's definitive Proxy Statement, dated January 12, 1999.
** 10.10	Registrant's Bylaws of The Exploration Company of Delaware, Inc., filed as Appendix D of the registrant's definitive Proxy Statement, dated January 12, 1999.
** 10.11	Registrant's Rights Agreement, filed as Exhibit 4.1 of the registrants Form 8-K, dated June 29, 2000 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.

**	10.12	Loan Agreement dated March 4, 2002, between The Exploration Company and Hibernia National Bank, filed as Exhibit 10.12 to Registrant's Annual report on Form 10-K, dated March 31, 2003.
**	10.13	First Amendment to Loan Agreement dated December 13, 2002 between The Exploration Company and Hibernia National Bank, filed as Exhibit 10.13 to Registrant's Annual report on Form 10-K, dated March 31, 2003.
**	10.14	Registrant's Certificate of Amendment of Certificate of Incorporation of The Exploration Company of Delaware, Inc., filed as Appendix B of the registrant's definitive Proxy Statement, dated May 25, 2001.
**	10.15	Registrant's Amendment to its Flexible Incentive Plan, filed as Proposal IV of the registrants definitive Proxy Statement, dated May 25, 2001.
	10.16	Number not used.
**	10.17	Registrant's Amendment to its Flexible Incentive Plan, filed as Proposal III of the registrants definitive Proxy Statement, dated April 25, 2003.
**	10.18	Registrant's Form S-8 Registration Statement for its 1995 Flexible Incentive Plan, dated December 15, 2003.
	10.19	Second Amendment to Loan Agreement and Waiver No. 2 dated August 13, 2003 between The Exploration Company and Hibernia National Bank, filed herewith.
	10.20	Sample of Change of Control Letter Agreements issued to all employees during December 2003.
	10.21	Registrant's Audit Committee Charter, as revised in January 2004, filed herewith.
	10.22	Third Amendment to Loan Agreement dated December 31, 2003 between The Exploration Company and Hibernia National Bank, filed herewith.
	10.23	Line of Credit Note dated December 31, 2003 between The Exploration Company and Hibernia National Bank, filed herewith.
	14	Code of Ethical Conduct for Senior Officers and Financial Managers, filed herewith.
	23.1	Consent of Akin, Doherty, Klein & Feuge, filed herewith.
	23.2	Consent of Netherland, Sewell & Associates, Inc., filed herewith
	31.1	Certification of Chief Executive Officer required pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934, as amended.
	31.2	Certification of Chief Financial Officer required pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934, as amended.
	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.
	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.

** Previously filed

(B) Reports on Form 8-K:

Four Form 8-K's were filed during the fourth quarter of 2003, as follows:

1. Dated October 9, 2003; Items 5, 7 and 9.
2. Dated October 24, 2003; Item 9.
3. Dated November 6, 2003; Items 7, 9 and 12.
4. Dated December 10, 2003; Item 9.

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

March 15, 2004

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

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signatures	Title	Date
/s/ Stephen M. Gose, Jr. Stephen M. Gose, Jr.	Chairman of the Board of Directors	March 15, 2004
/s/ Thomas H. Gose Thomas H. Gose	Director	March 15, 2004
/s/ James E. Sigmon James E. Sigmon	President and Director (Principal Executive Officer)	March 15, 2004
/s/ Michael J. Pint Michael J. Pint	Director	March 15, 2004
/s/ Robert L. Foree, Jr. Robert L. Foree, Jr.	Director	March 15, 2004
/s/ Alan L. Edgar Alan L. Edgar	Director	March 15, 2004
/s/ Charles W. Yates Charles W. Yates, III	Director	March 15, 2004
/s/ P. Mark Stark P. Mark Stark	Chief Financial Officer Vice-President-Finance (Principal Accounting Officer)	March 15, 2004

INDEPENDENT AUDITORS' REPORT

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, 2003 and 2002, and the related consolidated statements of operations, stockholders' equity and cash flows for the years ended December 31, 2003, 2002 and 2001. 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 U. S. generally accepted auditing standards. 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, 2003 and 2002, and the results of its operations and cash flows for the years ended December 31, 2003, 2002 and 2001, in conformity with U. S. generally accepted accounting principles.

We have also audited Schedule II of The Exploration Company for the years ended December 31, 2003, 2002 and 2001. In our opinion, this schedule presents fairly, in all material respects, the information required to be set forth therein.

/s/ Akin, Doherty, Klein & Feuge
AKIN, DOHERTY, KLEIN & FEUGE, P.C.
San Antonio, Texas
March 5, 2004

THE EXPLORATION COMPANY
Consolidated Balance Sheets

	December 31	
	2003	**2002**
Assets		
Current Assets		
Cash and equivalents	$ 6,180,560	$ 2,333,688
Accounts receivable:		
Joint interest owners	564,116	744,395
Oil and gas production	4,273,849	4,373,875
Prepaid expenses and other	718,853	503,176
Total Current Assets	11,737,378	7,955,134
Property and Equipment, net - successful efforts method of accounting for oil and gas properties	66,155,827	39,327,867
Other Assets		
Deferred tax asset	5,232,718	5,232,718
Other assets	1,080,290	520,600
Total Other Assets	6,313,008	5,753,318
Total Assets	$84,206,213	$53,036,319

See notes to audited consolidated financial statements.

THE EXPLORATION COMPANY
Consolidated Balance Sheets

	December 31	
	2003	**2002**
Liabilities And Stockholders' Equity		
Current Liabilities		
Accounts payable, trade	$ 8,186,705	$ 3,695,160
Other payables and accrued liabilities	3,709,016	3,176,564
Undistributed revenue	416,399	1,894,144
Current portion of long-term debt	1,752,286	1,073,773
Total Current Liabilities	14,064,406	9,839,641
Long-Term Liabilities		
Long-term debt, net of current portion	15,425,598	6,143,458
Redeemable preferred stock, Series B (redemption value - $16 million)	10,135,335	-
Accrued dividends - preferred stock	57,732	-
Asset retirement obligation	1,537,600	-
Total Long-Term Liabilities	27,156,265	6,143,458
Minority Interest in Consolidated Subsidiaries	193,441	82,846
Stockholders' Equity		
Preferred stock, Series A; authorized 10,000,000 shares, issued and outstanding -0- shares		
Common stock, par value $0.01 per share; authorized 50,000,000 shares, issued 22,242,849 and 20,109,516 shares, and outstanding 22,143,049 and 20,009,716	222,428	201,095
Additional paid-in capital	63,976,021	58,216,504
Accumulated deficit	(21,160,341)	(21,201,218)
Less treasury stock, at cost, 99,800 shares	(246,007)	(246,007)
Total Stockholders' Equity	42,792,101	36,970,374
Total Liabilities and Stockholders' Equity	$84,206,213	$53,036,319

See notes to audited consolidated financial statements.

THE EXPLORATION COMPANY
Consolidated Statements of Operations

	Years Ended December 31		
	2003	2002	2001
Revenues			
Oil and gas sales	$24,390,767	$16,049,798	$13,350,699
Gas gathering operations	15,145,154	2,596,955	-
Other operating income	9,281	311,611	408,221
Total Revenues	39,545,202	18,958,364	13,758,920
Costs and Expenses			
Lease operations	4,408,205	4,081,162	2,406,688
Production taxes	1,501,041	973,078	959,143
Exploration expenses	2,187,216	1,567,098	2,986,036
Impairment and abandonments	2,522,548	1,246,495	2,652,705
Gas gathering operations	15,136,279	2,625,313	-
Depreciation, depletion and amortization	8,627,678	6,500,625	3,201,517
General and administrative	3,716,439	2,025,440	1,481,284
Total Costs and Expenses	38,099,406	19,019,211	13,687,373
Income (loss) from operations	1,445,796	(60,847)	71,547
Other Income (Expense)			
Interest income	26,626	46,663	188,061
Interest expense	(1,365,233)	(273,213)	(128,373)
Loan fee amortization	(17,604)	(14,507)	-
Total Other Income (Expense)	(1,356,211)	(241,057)	59,688
Income (loss) before income taxes, minority interest and cumulative effect of change in accounting principle	89,585	(301,904)	131,235
Minority interest in income of subsidiaries	75,292	(84,066)	(106,518)
Income (loss) before income taxes and cumulative effect of change in accounting principle	164,877	(385,970)	24,717
Income tax (expense) benefit	(50,000)	75,000	(75,000)
Cumulative effect of change in accounting principle, net of tax	(74,000)	-	-
Net Income (Loss)	$ 40,877	$ (310,970)	$ (50,283)
Earnings (Loss) Per Share:			
Basic earnings before cumulative effect of change in accounting principle	$ 0.006	$ (0.016)	$ (0.003)
Cumulative effect of change in accounting principle	(0.004)	-	-
Basic Earnings Per Share	$ 0.002	$ (0.016)	$ (0.003)
Diluted earnings before cumulative effect of change in accounting principle	$ 0.005	$ (0.016)	$ (0.003)
Cumulative effect of change in accounting principle	(0.003)	-	-
Diluted Earnings Per Share	$ 0.002	$ (0.016)	$ (0.003)
Weighted average number of common shares outstanding:			
Basic	20,781,223	19,080,847	17,441,242
Diluted	21,295,257	19,080,847	17,441,242

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, 2000	17,471,849	$174,718	$43,986,983	$(20,839,965)	$ -	$23,321,736
Common stock options exercised	25,000	250	31,000	-	-	31,250
Purchases of treasury stock, at cost	-	-	-	-	(246,007)	(246,007)
Net loss for the year	-	-	-	(50,283)	-	(50,283)
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

See notes to audited consolidated financial statements.

THE EXPLORATION COMPANY
Consolidated Statements of Cash Flows

	Years Ended December 31		
	2003	**2002**	**2001**
Operating Activities			
Net income (loss)	$ 40,877	$ (310,970)	$ (50,283)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	8,627,678	6,500,625	3,201,517
Impairments and abandonments	2,522,548	1,246,495	2,652,705
Minority interest in (income) loss of subsidiaries	(75,292)	84,066	106,518
Cumulative effect of change in accounting principle	74,000	-	-
Non-cash interest expense and accretion of liability - redeemable preferred stock	677,002	-	-
Changes in operating assets and liabilities:			
Receivables	280,305	(3,175,627)	1,462,023
Prepaid expenses and other	(215,677)	(229,573)	(46,687)
Accounts payable and accrued expenses	3,226,251	3,274,414	1,238,229
Net cash provided by operating activities	15,157,692	7,389,430	8,564,022
Investing Activities			
Development and purchases of oil and gas properties	(36,071,216)	(27,381,247)	(13,675,327)
Purchase of other equipment	(396,925)	-	-
Proceeds from sale of oil and gas properties	-	200,000	2,005,133
Changes in minority interests	185,886	(434,325)	(108,902)
Other changes	-	(39,036)	(116,007)
Net cash (used) by investing activities	(36,282,255)	(27,654,608)	(11,895,103)
Financing Activities			
Proceeds from issuance of redeemable preferred stock, net of offering costs	9,229,931	-	-
Proceeds from long-term debt obligations	11,190,530	7,439,915	153,231
Payments on long-term debt obligations	(1,229,876)	(1,084,861)	(486,244)
Proceeds from common stock transactions, net of expenses	5,780,850	14,224,648	31,250
Purchases of treasury stock	-	-	(246,007)
Net cash provided (used) by financing activities	24,971,435	20,579,702	(547,770)
Change in Cash and Equivalents	3,846,872	314,524	(3,878,851)
Cash and Equivalents at Beginning of Year	2,333,688	2,019,164	5,898,015
Cash and Equivalents at End of Year	$ 6,180,560	$ 2,333,688	$ 2,019,164
Supplemental Disclosures:			
Cash paid for interest	$ 1,200,230	$ 273,213	$ 128,373
Cash paid for income taxes	-	-	75,000

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.

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, 2003, 2002 and 2001. 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, 3-D seismic costs, development wells, and costs to drill and equip exploratory wells that find proved reserves are capitalized. Costs to drill 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.

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, an impairment is recognized.

Other Property and Equipment: Other 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.

NOTE A - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - continued

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.

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, 2003, 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 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. The following table illustrates the effect on net income and earnings per share 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 year ended December 31:

	2003	2002	2001
Net income (loss) as reported	$ 40,877	$(310,970)	$(50,283)
Deduct: Total stock-based compensation expense determined under the fair value based method for all awards, net of related tax effects	(585,236)	(241,109)	(307,520)
Pro forma earnings (loss)	$(544,359)	$(552,079)	$(357,803)
Earnings (loss) per common share:			
Basic, as reported	$ 0.002	$ (0.016)	$ (0.003)
Basic, pro forma	(0.026)	(0.029)	(0.021)
Diluted, as reported	0.002	(0.016)	(0.003)
Diluted, pro forma	(0.026)	(0.029)	(0.021)

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.

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.

NOTE A - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - continued

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 Financial Statements was recorded as a liability in accordance with this Statement.

The FASB and representatives of the accounting staff of the Securities and Exchange Commission are currently engaged in discussions regarding the application of certain provisions of SFAS No. 141, "Business Combinations," and SFAS No. 142, "Goodwill and Other Intangible Assets," to companies in the extractive industries, including oil and gas companies. The FASB and the SEC staff are considering whether the provisions of SFAS No. 141 and SFAS No.142 require registrants to classify costs associated with mineral rights, including both proved and unproved lease acquisition costs, as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures.

Historically, the Company has included oil and gas lease acquisition costs as a component of oil and gas properties, which amounted to approximately $9.0 million at December 31, 2003, and $5.5 million at December 31, 2002, net of amortization. In the event the FASB and SEC staff determine that costs associated with mineral rights are required to be classified as intangible assets, such costs may be required to be separately classified on its balance sheets as intangible assets or further described in footnote disclosures. However, the Company currently believes that its results of operations and financial condition would not be materially affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with existing successful efforts accounting rules and impairment standards. The Company does not believe the classification of oil and gas lease acquisition costs as intangible assets would have any impact on the Company's compliance with covenants under its debt agreements.

Reclassifications: Certain amounts for 2002 and 2001 have been reclassified to conform to the 2003 presentation.

NOTE B - PROPERTY AND EQUIPMENT

Property and equipment consists of the following at December 31:

	2003	**2002**
Oil and gas properties	$92,715,667	$56,994,583
Other property and equipment	1,804,096	1,407,171
Total Property and Equipment	94,519,763	58,401,754
Accumulated depreciation, depletion and amortization	(26,164,119)	(17,585,395)
Reserve for impairment on unproved properties	(2,199,817)	(1,488,492)
Net Property and Equipment	$66,155,827	$39,327,867

NOTE C - LONG-TERM DEBT

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

	2003	**2002**
Note payable to a financial institution under Bank Credit Facility (see below), with interest at prime, monthly payments of interest only, with final payment due in 2006, and collateralized by accounts receivable and certain oil and gas properties.	$14,000,000	$5,800,000
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.	311,010	540,885
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.	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.	12,986	20,931
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 2004, and unsecured.	209,217	214,240
Note payable to a vendor, due in monthly installments of $320,588, paid in full in 2003.	-	641,175
Total long-term debt	17,177,884	7,217,231
Less current portion	(1,752,286)	(1,073,773)
Long-term portion of debt	$15,425,598	$6,143,458

The following is a schedule of principal maturities of long-term debt as of December 31, 2003:

Year Ended December 31,	**Amount**
2004	$ 1,752,286
2005	1,425,598
2006	14,000,000
	$17,177,884

Bank Credit 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, compared with a borrowing base of $12 million, with borrowings of $5.8 million, and unused borrowing capacity of $6.2 million at December 31, 2002. The unused borrowing base at March 5, 2004, was $1.05 million. Interest is payable monthly, with principal due at maturity in March 2006. Proceeds are used for the acquisition and development of oil and gas properties and general corporate working capital purposes. The Facility provides the lender with semiannual scheduled redeterminations, at mid-year and each subsequent anniversary date, while providing for two unscheduled redeterminations per year, at the Company's discretion. Borrowings under the Facility are secured by a first priority mortgage covering the Company's working and other interests in the majority of its oil and gas leases. The Facility also provides the lender with a commitment fee equal to 0.5%, per annum on the unused borrowing base.

NOTE C - LONG-TERM DEBT - continued

The Facility contains certain financial covenants and other negative restrictions common for a financing of this type. At December 31, 2003, the Company was not in compliance with the Current Ratio covenant. The Company received a waiver related to this covenant for the December 31, 2003 and March 31, 2004 reporting periods, and expects to be in compliance with the covenant at June 30, 2004 and subsequent periods. Accordingly, the Credit Facility is classified as long-term.

The interest rate under the Facility, during 2002 and 2003, was based on the Wall Street Journal Prime Rate plus applicable margin ("base rate"). A Eurodollar Rate plus applicable margin may be utilized at the election of the Company. The interest rate at December 31, 2003, was 4.0%. The agreement was amended, effective December 31, 2003 to provide for two tranches with separate repayment terms and interest rates. Tranche A has similar interest terms to the original agreement, with lower applicable margins on the Eurodollar Rate option, and applies to the first $12.5 million of borrowings. Tranche B applies to borrowings above $12.5 million with interest at the Eurodollar Rate plus 400 basis points. Any borrowings then outstanding under Tranche B will be payable on January 1, 2005. At March 5, 2004, the outstanding balance was $12.95 million. The rate in effect at March 5, 2004 was 4.0% on $12.5 million of borrowings, and 5.1% of the excess over $12.5 million.

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%. Payments are due in two installments of $1,406,422 each in January 2004 and 2005.

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.

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. In addition, the Company recorded 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, nor would it have had a material impact on 2002 assuming adoption on a pro-forma basis. This Statement is not expected to have an additional material impact on the Company's financial position or operations in future periods. At December 31, 2003 the asset retirement obligation was $1.5 million.

The following is a reconciliation of the asset retirement obligation for the year ended December 31, 2003:

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

NOTE E - REDEEMABLE PREFERRED STOCK, SERIES B

In August 2003, the Company authorized and 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 bears interest at 8% of stated value, 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 at the end of six years. 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, Series A, none of which has been issued at December 31, 2003. The Board of Directors has not established terms of the stock. The Company has authorized 16,000 shares of redeemable preferred stock, Series B, all of which is outstanding at December 31, 2003. See Note E.

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 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 from closing.

Private Placement - 2002: In May 2002, the Company issued 2,499,667 shares of restricted common stock at a price of $6.00 per share to a group of 10 institutional investors. The Company raised $14,051,893, net of offering costs of $946,112, to be used for oil and gas property acquisition and development, 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.

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.

NOTE F - STOCKHOLDERS' EQUITY-continued

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, 2003.

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 did not purchase any common stock under this program during 2002 or 2003.

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 dividends which may be declared and paid to no more than 50% of net income for the prior year-end, after consideration of the Series B requirements.

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 2,214,305 shares of the Company's common stock. 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 as of the year ended December 31:

	2003	2002	2001
Risk-free interest rate	4.67%	3.12%	4.40%
Expected dividend yield	0%	0%	0%
Expected volatility of common stock	.90	.90	.79
Expected weighted-average life of option	3 years	4 years	5 years

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.

NOTE F - STOCKHOLDERS' EQUITY - continued

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, 2000	1,433,800	$2.33		526,800
Granted	205,000	2.96	$1.82	
Exercised	(25,000)	1.25		
Forfeited	(9,800)	3.91		
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

The following table summarizes information about the options outstanding at December 31, 2003:

	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	4.83 years	$0.98	25,000	$0.98
1.25	8,000	4.68 years	1.25	8,000	1.25
2.12	728,000	4.64 years	2.12	428,000	2.12
2.62	50,000	2.68 years	2.62	50,000	2.62
2.75	100,000	1.12 years	2.75	100,000	2.75
2.78	75,000	6.40 years	2.78	75,000	2.78
2.96	177,000	7.59 years	2.96	177,000	2.96
3.09	300,000	5.08 years	3.09	300,000	3.09
4.38	145,000	9.47 years	4.38	-	-
5.17	75,000	9.64 years	5.17	-	-
	1,683,000		$2.78	1,163,000	$2.59

***Stock Warrants**:* The following is a summary of warrants outstanding at December 31, 2003:

Purpose of Warrants	Number of Shares	Range of Prices	Wt.-Avg. Exercise Price	Wt.-Avg. Remaining Contractual Life
Financing	1,566,429	$2.88 - $6.00	$3.06	1 year

Subsequent Event: Subsequent to year-end, warrants to purchase 1,238,096 shares of common stock were exercised, resulting in cash proceeds to the Company of approximately $3.5 million, net of an advisory fee of approximately $223,000. The advisory fee on the exercise was paid to a Director of the Company under an agreement in place since prior to the appointment of the Director to the Board.

THE EXPLORATION COMPANY
Notes to Audited Consolidated Financial Statements
Years Ended December 31, 2003, 2002 and 2001

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, 2003:			
Basic EPS:			
Net income	20,781,223	$ 40,877	$ 0.002
Effect of dilutive options	514,034	-	-
Dilutive EPS	21,295,257	$ 40,877	$ 0.002
Year Ended December 31, 2002:			
Basic EPS:			
Net income	19,080,847	$ (310,970)	$(0.016)
Effect of dilutive options	-	-	-
Dilutive EPS	19,080,847	$ (310,970)	$(0.016)
Year Ended December 31, 2001:			
Basic EPS:			
Net income	17,441,242	$ (50,283)	$(0.003)
Effect of dilutive options	-	-	-
Dilutive EPS	17,441,242	$ (50,283)	$(0.003)

The 2002 and 2001 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 $294,000 in 2003, $170,000 in 2002 and $146,000 in 2001. Future minimum rentals under all noncancelable leases are as follows:

Year Ended December 31,	Amount
2004	$316,000
2005	307,000
2006	306,000
2007	179,000

THE EXPLORATION COMPANY
Notes to Audited Consolidated Financial Statements
Years Ended December 31, 2003, 2002 and 2001

NOTE I - INCOME TAXES - continued

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

	2003	2002	2001
Current federal tax benefit (expense)	$(50,000)	$75,000	$(75,000)
Deferred federal tax benefit (expense)	-	-	-
Income tax benefit (expense)	$(50,000)	$75,000	$(75,000)

	2003	2002	2001
Deferred tax assets:			
Tax net operating loss carryforwards	$3,600,000	$4,600,000	$4,860,000
Impairment of oil and gas properties	4,700,000	3,400,000	3,010,000
Net deferred tax assets	8,300,000	8,000,000	7,870,000
Deferred tax liability:			
Accumulated depreciation	(75,000)	-	-
Gross deferred tax liability	(75,000)	-	-
Net deferred tax assets	8,225,000	8,000,000	7,870,000
Less valuation allowance	(2,992,282)	(2,767,282)	(2,637,282)
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 $10,700,000 ($3,600,000 tax benefit) at December 31, 2003 expire in stages from 2008 to 2019. 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 remaining 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:

	2003	2002	2001
Expected federal tax benefit (expense)	$(19,000)	$131,000	$ (3,700)
Change in valuation allowance	-	-	(730,000)
Other changes	(31,000)	(56,000)	658,700
Income tax benefit (expense)	$(50,000)	$ 75,000	$ (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
Year ended December 31, 2003	20%	18%	39%
Year ended December 31, 2002	23%	10%	14%
Year ended December 31, 2001	-	30%	55%

THE EXPLORATION COMPANY
Notes to Audited Consolidated Financial Statements
Years Ended December 31, 2003, 2002 and 2001

NOTE K - 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:

	2003	2002
Proved properties	$62,871,668	$38,733,563
Less accumulated depreciation, depletion and amortization	(25,395,371)	(17,025,745)
Net proved properties	37,476,297	21,707,818
Unproved properties:		
Coalbed methane properties	7,871,096	7,009,569
Drilling in-progress	10,792,940	4,298,087
Oil and gas leasehold acreage	11,179,963	6,953,364
Total unproved properties	29,843,999	18,261,020
Less reserve for impairment	(2,199,817)	(1,488,492)
Net unproved properties	27,644,182	16,772,528
Net capitalized cost	$65,120,479	$38,480,346

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

	2003	2002	2001
Property acquisition costs, unproved	$11,744,304	$ 5,866,791	$ 1,627,967
Property development and exploration costs:			
Conventional oil and gas properties	27,141,935	14,117,482	11,168,228
Coalbed methane properties	571,334	1,047,256	4,880,853
Gathering system	310,096	5,649,181	94,270
Depreciation, depletion and amortization	8,259,914	6,306,511	3,040,932
Depletion per equivalent Mcf of production	1.71	1.44	1.02

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.

THE EXPLORATION COMPANY
Notes to Audited Consolidated Financial Statements
Years Ended December 31, 2003, 2002 and 2001

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

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:

	2003	2002	2001
Proved developed and undeveloped reserves:			
Natural gas (Mcf):			
Beginning of year	14,675,000	10,976,000	4,532,000
Extensions and discoveries	8,975,000	5,103,000	8,664,000
Reserves purchased	671,000	-	-
Production	(2,108,000)	(2,487,000)	(2,673,000)
Revisions of previous estimates	(6,589,000)	1,083,000	453,000
End of year	15,624,000	14,675,000	10,976,000
Crude Oil (Bbls):			
Beginning of year	1,479,000	294,000	183,000
Extensions and discoveries	1,330,000	600,000	66,000
Reserves purchased	1,000	674,000	-
Production	(454,000)	(314,000)	(50,000)
Revisions of previous estimates	(227,000)	225,000	95,000
End of year	2,129,000	1,479,000	294,000
Proved developed reserves			
Natural gas (Mcf):			
Beginning of year	6,213,000	5,102,000	4,532,000
End of year	9,896,000	6,213,000	5,102,000
Crude Oil (Bbls):			
Beginning of year	988,000	133,000	183,000
End of year	1,340,000	988,000	133,000

The Company's coalbed methane properties are classified as unproved as the project is still dewatering at December 31, 2003. Undeveloped reserves of natural gas attributable to the coalbed methane project are approximately 220,000 Mcf at year-end.

THE EXPLORATION COMPANY
Notes to Audited Consolidated Financial Statements
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NOTE K - OIL AND GAS PRODUCING ACTIVITIES AND PROPERTIES - continued

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 $5.77, $4.90 and $2.72 per Mcf of gas and $30.06, $28.71 and $17.70 per barrel of oil as of December 31, 2003, 2002 and 2001. 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. The standard measure is as follows for the years ended December 31:

	2003	2002	2001
Future cash inflows	$154,215,000	$114,337,000	$35,359,000
Future production and development costs	(65,263,000)	(49,207,000)	(16,331,000)
Future net cash inflows before income tax	88,952,000	65,130,000	19,028,000
Future income tax expense	(14,802,000)	(10,400,000)	-
Future net cash flows	74,150,000	54,730,000	19,028,000
10% annual discount to reflect timing of net cash flows	(26,801,000)	(16,583,000)	(5,045,000)
Standardized measure of discounted future net cash flows relating to proved reserves	$ 47,349,000	$ 38,147,000	$13,983,000

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:

	2003	2002	2001
Standardized measure, beginning of year	$38,147,000	$13,983,000	$31,960,000
Extensions and discoveries	32,409,000	27,024,000	8,505,000
Reserves purchased	1,591,000	4,645,000	-
Sales and transfers, net of production costs	(18,482,000)	(10,838,000)	(9,985,000)
Revisions in quantity and price estimates	(292,000)	11,966,000	(15,881,000)
Net change in income taxes	(2,209,000)	(7,235,000)	2,580,000
Accretion of discount	(3,815,000)	(1,398,000)	(3,196,000)
Standardized measure, end of year	$47,349,000	$38,147,000	$13,983,000

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, 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
Year Ended December 31, 2001				
Allowance for doubtful accounts, trade accounts	$ 27,000	$ -	$ -	$ 27,000
Impairment of oil and gas properties	2,085,351	2,627,705	(3,851,743)	861,313
Deferred tax asset valuation allowance	1,907,282	730,000	-	2,637,282