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, 2002
OR

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

COMMISSION FILE NUMBER 000-33275

Warren Resources, Inc.
(Exact name of registrant as specified in its charter)

Delaware	**11-3024080**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

489 Fifth Avenue, New York, New York 10017
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: (212) 697-9660

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

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

Common Stock, $.0001 par value per share
(Title of Class)

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

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

The aggregate market value of the registrant's voting Common Stock held by non-affiliates of the registrant as of March 27, 2003: there is no publicly quoted market value for the registrant's voting Common Stock. As of March 27, 2003, there were 17,581,996 shares of the registrant's voting Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: NONE

WARREN RESOURCES, INC.
FORM 10-K

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Warren's logo is a trademark or service mark of Warren. Other trademarks or service marks appearing herein are the property of their respective holders.

As used in this document, "Warren," "we," "us," and "our" refer to Warren Resources, Inc. and its subsidiaries. The term "Warren E & P" refers to our wholly owned subsidiary Petroleum Development Corporation (which is in the process of changing its corporate name to Warren E & P, Inc.) and its subsidiaries. The term "Pinnacle" refers to our wholly owned subsidiary CJS Pinnacle Petroleum Services, LLC, which was formerly engaged in providing well services.

For abbreviations or definitions of certain terms used in the oil and gas industry and in this registration statement, please refer to the section entitled "Glossary of Oil and Gas Terms" beginning on page 27.

PART I

The statements contained in this annual report on Form 10-K that are not historical are "forward-looking statements," as that term is defined in Section 21E of the Exchange Act, that involve a number of risks and uncertainties. Forward-looking statements use forward-looking terms such as "believe," "expect," "may," "intend," "will," "project," "budget," "should," "anticipate" or other similar words. These statements discuss forward-looking information such as:

- anticipated capital expenditures and budgets;
- future cash flows and borrowings;
- pursuit of potential future acquisition or drilling opportunities;
- sources of funding for exploration and development;
- estimated oil and gas reserves;
- market conditions in the oil and gas industry; and
- the anticipated outcome of litigation and the impact of governmental regulations.

These forward-looking statements are based on assumptions that we believe are reasonable, but they are open to a wide range of uncertainties and business risks, including the risks described under "Risk Factors" contained in Management's Discussion and Analysis of Financial Condition and Results of Operations in this Form 10-K, and actual operations and results may differ materially from those expressed in this Form 10-K. When considering these forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this registration statement. We will not update these forward-looking statements unless the securities laws require us to do so.

Items 1 and 2: Business and Properties

Overview

We are an independent energy company engaged in the acquisition, exploration and development of domestic onshore natural gas and oil reserves. We own natural gas and oil interests in approximately 301,029 gross (137,626 net) acres. Less than 5% of our net acreage has been developed. We are an active developer of coalbed methane natural gas in the Rocky Mountain region. We own natural gas interests in approximately 231,623 gross (127,628 net) acres in Rocky Mountain areas where there is significant coalbed methane drilling activity. Of this acreage, we own or have under contract coalbed methane gas interests in approximately 226,433 gross (126,721 net) acres in the Washakie Basin, which comprises approximately the southeast third of the Greater Green River Basin in Wyoming. Our remaining coalbed methane acreage is located in the Powder River Basin of Wyoming. Additionally, we own natural gas and oil interests in properties in east Texas and in the Los Angeles Basin of California that we are developing primarily through directional and horizontal drilling.

Our principal source of funding for exploration, development and production activities has been privately placed drilling programs that we sponsor and manage. Since 1992, we have sponsored 30 drilling programs that have raised approximately $222 million. We acquire acreage, develop drilling prospects and manage the drilling activity in which our drilling program investors participate. We contribute acreage to the drilling programs and pay all tangible drilling costs, while the other investors in the drilling programs pay all intangible drilling costs. Warren E & P, our wholly owned subsidiary, typically contracts with the drilling programs to conduct drilling services on a turnkey, fixed-price basis. Under such contracts, the drilling programs pay a specific price to Warren E & P, based on the depth of the well, for each well drilled regardless of the actual amount of time, materials and expenses required by Warren E & P to drill the well. Other than the interest we hold in our drilling programs and joint ventures on a direct or an indirect basis, we have not retained any additional interest in the wells drilled for the account of our drilling programs and joint ventures.

All of our natural gas and oil drilling, completion, production and land operations are conducted through Warren E & P, a New Mexico corporation formed on March 26, 1973. Warren E & P is currently based in Albuquerque, New Mexico with regional offices in Gillette, Wyoming. In April 2003, Warren E & P will be moving its headquarters to Casper, Wyoming.

At December 31, 2002, we had estimated net proved reserves of 82.4 Bcfe. We own approximately 55% of these reserves through our interest in the drilling programs we manage and 45% directly. Based on average prices on that date of $3.36 per Mcf of natural gas and $27.15 per Bbl of oil, the PV-10 value of these proved reserves was approximately $114 million. At December 31, 2002, our drilling programs had 33.7 Bcfe of estimated net proved reserves with a PV-10 value of approximately $56 million, not including our interests in these programs.

As of December 31, 2002, we had interests in 203 producing wells and were the operator of 65% of these wells. As of the same date, the daily gross production of these wells was 21.2 Mmcfe, of which 7.2 Mmcfe was attributable to Warren and its drilling programs. Although Warren was entitled to a percentage of production, historically, due to production subordination agreements with our drilling programs, substantially all production was allocated to investors in our prior drilling programs. Since July 1, 2001, 25% of new production from interests in wells owned by the drilling programs formed in 1999 and subsequent years was directly allocated to Warren pursuant to governing agreements with our drilling programs.

Our exploration and development is focused on:

- coalbed methane in Wyoming and other areas of the Rocky Mountain region; and
- water flood redevelopment in the Wilmington Field in California.

We have significant operational experience in drilling and producing coalbed methane and in designing and drilling directional and horizontal wells. Specifically, we have drilled over 190 coalbed methane wells in the Powder River and Washakie Basins since commencing such operations in 1995. We have also managed full scale field development of several areas in the Powder River Basin. Additionally, we have drilled more than 120 horizontal and directional wells covering approximately 20 different geological formations in many of the major domestic producing on-shore basins. The executives who manage our natural gas and oil operations have extensive experience in drilling, completion and production activities. We believe our experience with highly specialized drilling and completion operations allows us to more efficiently develop our existing property base and better evaluate new opportunities. For more information about the experience and background of our executives and significant employees see "Item 10ªDirectors and Executive Officers."

Coalbed Methane Properties

Coalbed Methane Compared to Traditional Natural Gas

The primary component of commercial natural gas is methane. Methane can also be found in coal deposits, as it is created by the same biological and geological forces that transform organic material into coal. Methane is stored in coal seams in four different ways:

- as free gas trapped within the pore spaces and natural fractures of the coal;
- as dissolved gas in the water within the coal seam;
- as adsorbed gas on the surface of the coal; and
- as adsorbed gas held within the molecular structure of the coal itself.

Methane stored in coal deposits by all four of these methods is released upon the removal of water from coal seams. The removal of water reduces the amount of pressure on free and dissolved gas in the coal allowing it to be produced. As a result, coalbed methane wells typically produce significant amounts of water when they are first drilled, often for the first one or two years of a generally projected eight to fifteen year life of these wells. During this de-watering phase, water production typically decreases while gas production typically increases. After this initial production phase, gas production typically declines over the remaining producing life of the wells.

While traditional natural gas wells and coalbed methane wells require largely the same infrastructure and produce the same end product, coalbed methane production differs from traditional natural gas production in the following ways:

- Other than dehydration and compression, coalbed methane typically needs no other processing after extraction prior to entering a pipeline, reducing production costs;
- Although certain structural features such as fractures enhance production of coalbed methane, such structural features are generally not necessary for production, making the discovery of coalbed methane reserves less expensive;
- Methane bearing coals exist at much shallower depths than the formations that traditionally contain natural gas, allowing coalbed methane to be produced from shallower wells using more readily available equipment, such as water well rigs, thereby reducing drilling costs; and
- Since the location of coal seams is typically known through prior mining activity or from data provided by existing wells drilled to deeper formations, extensive geophysical or seismic data is not usually required to drill a coalbed methane well.

It should be noted that coalbed methane reservoirs require a cleat system to be productive. Cleats are formed during the coalification process and provide the path for the methane to travel to the wellbore. The size and number of the cleats determines the permeability and product of the coalbed reservoir. It is possible that an adequate cleat system may not develop.

Our Coalbed Methane Operations

We have two primary areas of operations in the Rocky Mountain region. While most of our drilling activity to date has occurred in the Powder River Basin, most of our acreage is located in the Washakie Basin. Our ownership in this acreage is held principally through working interest leaseholds. The primary drilling season in these areas runs from May through January due to weather and environmental considerations. Since 1995, we have been operating in the Powder River Basin of Wyoming and have drilled 131 coalbed methane wells in three fields in the Powder River Basin, all of which we operate. As of December 31, 2002, the average daily production from these three fields was 5.1 Mmcf per day, of which 3.5 Mmcf was attributable to us and our drilling programs. As of

December 31, 2002, we held leases covering approximately 5,190 gross (907 net) acres in the Powder River Basin with proved coalbed methane reserves of 1.9 Bcfe having a PV-10 of $2.2 million attributable to our net interest, or approximately 2% of our net proved reserves.

In the second half of 1999, we began acquiring acreage in the Washakie Basin, which is a portion of the greater Green River Basin in south-central Wyoming. We currently own approximately 155,454 gross (68,332 net) acres in an area of mutual interest (the "AMI") with Anadarko Petroleum Corporation (as discussed below) and 70,979 gross (58,389 net) acres outside of the same AMI area, for a total of approximately 226,433 gross (126,721 net) acres in the Washakie Basin. In 2000, we participated in an initial test program on this acreage in which 21 wells were drilled to test the quality of the coals in this basin. During 2001 and 2002, we drilled an additional 36 coalbed methane wells in the Washakie Basin, of which 32 wells appear to be commercially productive. Based on the test data from these wells, production data from 10 of the wells and our six years of experience operating coalbed methane wells in the Powder River Basin, we believe that the gas content of the coals in the Washakie Basin will significantly exceed the gas content of the coals in the Powder River Basin. Currently, Warren has an interest in 10 wells producing approximately 1.7 Mmcf/d and 22 wells believed to be commercially productive that are awaiting completion or connection to sales lines in the Washakie Basin. On June 1, 2001, the Bureau of Land Management of the U.S. Department of the Interior, or "BLM," issued a policy statement that allows for the drilling of a maximum of 200 wells in the Washakie Basin, subject to restrictions discussed below, during the preparation of an environmental impact statement currently targeted for completion by the end of 2004. Of these 200 wells, we were allocated the right to drill 165 gross wells, including our interest in the non-producing wells and before our conveyance of an undivided 50% interest in the AMI to Anadarko Petroleum Corporation as described below.

Powder River Basin

LX-Bar and Piper Federal/Haight-Less Fields

In these fields, we own interests in approximately 5,190 gross (907 net) acres located near the town of Gillette in Campbell County, Wyoming. Our total estimated net proven reserves in this portion of the Powder River Basin at December 31, 2002 were 1.9 Bcfe, substantially all of which were attributable to coalbed methane. In 1999, we drilled 56 wells in the LX-Bar Field, 44 of which are currently producing, with an additional 48 wells drilled since March 2000, 37 of which are currently producing or believed by us to be capable of producing. We together with our drilling programs have an average working interest of approximately 91% and we operate 100% of the wells in this field. At December 31, 2002, gross production from these wells in the LX-Bar Field was approximately 4.3 Mmcf per day, of which 2.9 Mmcf per day was attributable to us and our drilling programs.

Wells in the LX-Bar Field produce from two coal seams. The shallower seam is the Anderson seam, at an average depth of 450 feet, with an average net thickness of 35 feet. The average cost in the Anderson seam has been approximately $70,000 per well, including gathering and compression systems and pipeline connections. The deeper coal seam is the Canyon seam, the depth of which averages 800 feet, with an average net thickness of 65 feet. The average cost in the Canyon seam has been approximately $125,000 per well, including gathering and compression systems and pipeline connections. We have identified a third potential coal seam, the Lower Canyon, at an average depth of 900 feet, which we are currently drilling for evaluation.

To transport our gas from our LX-Bar area, we converted an existing 6.5 mile oil pipeline to a gas pipeline in the third quarter of 1999. This pipeline allows us to sell our gas into the Williston Basin Interstate pipeline which serves markets in the Midwest and has historically provided a higher price than markets available from pipelines to the south of this area. Selling our gas into the Williston Basin Interstate pipeline allows us to sell to the Ventura Gas Market as opposed to selling into the Colorado

Interstate Gas, "CIG," at CIG's posted price. Gas prices throughout the major domestic markets, including in the Rocky Mountain region, have experienced extreme volatility over the past 12 months. Gas prices in the Rockies have ranged from below $1.00 per Mcfe to over $7.00 per Mcfe over the past year. We currently hold 6 Mmcf per day of firm transport, and typically sell any additional LX-Bar production on an interruptible basis on this line. This means that from time to time the sale of the production into this pipeline may be delayed or interrupted for production for which other sellers have space on the pipeline on a firm commitment basis. Historically, these delays and interruptions have not been significant.

Since August 2000, we have drilled 25 wells in the Piper Federal Field, of which 22 are producing as of December 31, 2002. The remaining wells are not capable of commercial production. All of our current wells in the Piper Federal Field produce from the shallow Wyodak coal seam, which has an average depth of 850 feet and an average net thickness of 80 feet. Prior to 2000, we participated in the drilling of eight wells in the Haight-Less Field. All of these wells produced from the shallow Wyodak coal seam. Our average cost per well in this seam has been approximately $100,000, including gathering and compression systems and pipeline connections. We operate 100% of the wells in these fields. At December 31, 2002, these wells were producing approximately 0.8 Mmcf per day gross, of which 0.6 Mmcf is attributable to us and our drilling programs. We plan to test a deeper coal seam at 1,350 feet during 2003. The production from these wells is sold into a Colorado Interstate Gas pipeline on an interruptible basis.

Kirby-Decker Prospect

We sold our entire 24,133 gross (22,075 net) acres position in this field in Bighorn County, Montana to a third party effective August 7, 2002 for a cash consideration of $895,040. Prior to this sale, we had drilled two wells in the northern portion of the acreage that we deemed nonproductive.

Washakie Basin

The Washakie Basin is a sub-basin on the eastern flank of the Greater Green River Basin in Wyoming. In the eastern section of Warren's Washakie Basin property, the Mesa Verde formation dip angle is 1-2 degrees. The Mesa Verde formation contains coals which are generally shallow (700 to 1500 feet). Then, it plunges to 16-20 degrees on the Western rim of the Washakie Basin along a 54 mile hinge line to an approximate depth of 7,000 feet. The hinge line forms at the point at which the Mesa Verde formation begins to plunge. Based on the data we have collected, we believe the gas content of the coals in this basin should significantly exceed the gas content of the coal deposits of the Powder River Basin. During 2002, we commenced production and gas sales from 10 coalbed methane wells (drilled on 80-acre spacing) in the "Sun Dog Unit" on Sections 8 and 17 in Township 16 North, Range 91 West, in the Washakie Basin in Carbon County, Wyoming. Currently, there is very limited coalbed methane production in the Washakie Basin other than the foregoing and 1.5 Mmcfe per day coalbed methane production reported by an offset operator.

Recent Developments in the Washakie Basin

On December 13, 2002, we consummated the following joint transactions affecting our properties in the Washakie Basin with Anadarko E & P Company LP, a wholly-owned subsidiary of Anadarko Petroleum Corporation (collectively, "Anadarko"): (i) an Exchange Agreement dated December 11, 2002 (the "Exchange Agreement"), which is effective as of August 1, 2002 (the "Effective Date") and was closed on December 13, 2002 ("Closing Date"); and (ii) a Joint Exploration Agreement dated December 13, 2002 (the "Joint Exploration Agreement"), which is effective as of August 1, 2002.

The Anadarko Exchange Agreement

Pursuant to the Exchange Agreement, Anadarko acquired an undivided 50% interest in our right, title, and interest in and to any oil and gas lease, mineral interest in the oil and gas estate, or the right to earn any such interest under a farmout contract, farmout option contract, support agreement or other right to explore for oil or gas in the lands (collectively referred to herein as the "Warren Properties", which includes properties owned by Warren and its affiliates) within a defined area of mutual interest consisting of approximately 141,438 net to Warren and Anadarko (155,453 gross to Warren and Anadarko) acres in an area of mutual interest (the "AMI Area") located in the Atlantic Rim formation within the Washakie Basin, Carbon County, Wyoming (the "Atlantic Rim"), of which approximately 86,394 net acres were owned by Warren prior to the Closing; limited to all those depths between the surface of the earth and the stratigraphic equivalent of the base of the Mesaverde formation (the "Depths").

At the Closing, Anadarko delivered to Warren the following consideration:

- $12,000,000 in cash (the "Cash Purchase Price") to acquire an undivided 50% of Warren's interest in and to the Warren Properties;
- A deferred payment commitment of $6,000,000 ("Deferred Purchase Price") for the three year period commencing as of the Effective Date (the same being August 1, 2002) and ending on July 31, 2005 (the "Deferred Payment Period"). During the Deferred Payment Period Anadarko will pay for Warren's proportionate share of the costs associated with exploration and development of oil and gas from the AMI Area during each of the three twelve-month periods after the Effective Date until Anadarko has paid $2,000,000 for each such twelve-month period. Subject to mutually agreed upon force majeure events, on each anniversary of the Effective Date during the Deferred Payment Period, Anadarko will pay Warren the difference, if any, between $2,000,000 and the amount of costs and expenses actually paid by Anadarko during the preceding twelve month period pursuant to this provision. Any amounts paid by Anadarko in excess of the $2,000,000 during any such twelve month period will be credited against the next installment of the Deferred Purchase Price due during the next twelve month period; and
- A $4,285,902.70 cash reimbursement for 100% of the reasonable costs incurred by Warren on or with respect to development of the Warren Properties from and after the Effective Date, and 100% of the reasonable costs incurred by Warren before the Closing Date attributable to NEPA compliance with respect to the AMI Area. Fifty percent (50%) of the above-referenced development costs and NEPA costs were credited against and reduced the Deferred Purchase Price. The parties entered into a Cost Sharing Arrangement, as described in of the Exchange Agreement, for purposes of sharing the above-referenced NEPA costs that will be incurred after the Closing Date; a portion of the which costs will be credited against and reduce the Deferred Purchase Price.

Additionally, at the Closing, Anadarko:

- pursuant to the Joint Exploration Agreement created and delivered to Warren an undivided 50% contractual interest in its unencumbered fee mineral interest in the oil and gas estate in lands within the AMI Area consisting of approximately 49,846 gross and net acres, memorialized by a recordable and assignable (subject to mutually agreeable limitations or as provided herein) form of Memorandum of Pooling, limited to the Depths and subject to a reserved royalty interest of 17.5%, proportionately reduced, and subject to the termination provisions contained within the Joint Exploration Agreement (the "Anadarko Fee Lands"); and
- pursuant to the Exchange Agreement, transferred, assigned and conveyed to Warren an undivided 50% of Anadarko's right, title, and interest in and to (a) any oil and gas lease(s) owned by Anadarko as of the Effective Date covering lands within the AMI Area consisting of

approximately 5,197 gross and net acres, all limited to the Depths, and (b) the right to earn any such interest under a farmout contract, farmout option contract, support agreement (with the exception of the Wamsutter AMI between Anadarko and BP/Amoco) or other right to explore for oil or gas on such lands, limited to the Depths (the "Anadarko Leases").

Anadarko Joint Exploration Agreement

The Joint Exploration Agreement contains the general terms and provisions described below:

- Initially, each party has a 50% interest in the AMI Area and Depths. The AMI shall terminate on the earlier to occur of: (i) the sixth anniversary of the date of the final Record of Decision from the U.S. Bureau of Land Management approving the currently pending Environmental Impact Statement covering the AMI Area and other adjacent lands (the "BLM Approval"); or (ii) July 31, 2012, unless mutually extended by both parties.
- Termination of the Joint Exploration Agreement and the AMI will not terminate any unit operating agreement covering lands within the AMI Area (or any other operating agreement covering non-unit lands within the AMI Area), so long as there is a well thereon which is producing oil or gas in paying quantities.
- Anadarko will take the lead in the preparation of any National Environmental Policy Act (NEPA) compliance documentation triggered by operations under the Joint Exploration Agreement within the AMI Area and/or defense of the same before administrative appeal boards and district courts, subject to a cost sharing arrangement that was entered into between Anadarko and Warren at the Closing.
- The Joint Exploration Agreement establishes the manner in which oil and gas development operations within the AMI Area will be conducted. The Joint Exploration Agreement creates four joint operational committees: an Executive Committee, and three Sub-committees, including an Exploration & Development Sub-Committee, a Production & Operations Sub-Committee and an Environmental & Regulatory Sub-Committee. All committees for the AMI Area consist of two members, one appointed by Anadarko and one appointed by Warren.
- Each federal exploratory unit will be governed by its own unit operating agreement (the "Unit Operating Agreement"), provided, however, in the event of a conflict, the rights and obligations of the parties shall be governed by the Joint Exploration Agreement.
- The Unit Operating Agreement includes, among other terms, a non-consent penalty wherein a party's election to not participate in the wells within a Drilling Block (as defined therein) will result in the forfeiture of the non-consenting party's interest in the entire Drilling Block, or in the entire Unit Area if a party does not participate in the initial pilot wells.

The Joint Exploration Agreement and Unit Operating agreement also provide, without limitation, the following:

- Anadarko will be the "Operator of Record" of each federal exploratory unit and companion Unit Operating Agreement; however, Warren will perform certain drilling, completion, construction and other operations pursuant to a Master Consulting Services Agreement executed at the Closing.
- The parties agreed to drill a maximum of 117 wells per calendar year within the AMI Area, unless the parties mutually agree to increase the number of wells in the AMI Area.
- The Joint Exploration Agreement contains provisions granting certain preferential rights with respect to interests purchased, transferred or assigned within the AMI Area.

As a result of the foregoing transactions, the total acreage contributed by the parties within the AMI Area in the Atlantic Rim is approximately 141,437 net acres, with Anadarko and Warren each having an undivided 50% interest in the net acreage, or 70,719 net acres each with the AMI Area. Additionally, Warren retained 100% of approximately 60,428 net acres in the Atlantic Rim Project outside the AMI Area, with an average net revenue interest of 82.5% based upon an 100% working interest, for a total of approximately 226,432 gross (131,147 net) acres in the Washakie Basin. We have been acquiring our acreage in the Washakie Basin since July 1999. In the first purchase in 1999 in the south half of the basin, we acquired approximately 40% of our current acreage through a series of purchases from a group of privately held independent companies at approximately $50 per acre, for a total consideration of $3.8 million. The remaining acreage in this basin was acquired in 2000 at an average cost of $105 per net acre, for an additional consideration of $8.5 million. Acreage costs in the Washakie Basin increased significantly between 1999 and 2002 due to positive results from a 21 well test drilled with Tower Columbia Corporation and Stone & Wolf and our subsequently drilling an additional 36 coalbed methane wells. These test drilling results substantiated the existence of commercial amounts of natural gas from the test wells and provided additional geological data that supported commercial development over a significantly greater potential area in the basin. The foregoing acreage in the Washakie Basin includes a farmout from Big West Oil & Gas, Inc. and Flying J Oil & Gas, Inc. which covers approximately 21,695 gross (17,655 net) acres and is subject to a 50% reduction if Big West elects to participate in the drilling of the wells, or a 30% reduction at well payout if they do not participate. Under the terms of our amended agreements with Big West and Flying J, we have drilled eight wells and completed related disposal facilities. Based on the completion of such wells, we have earned approximately 9,242 net acres under the Big West farmout; one-half of which was conveyed to Anadarko pursuant to the Exchange Agreement discussed above.

Based on the initial well test program, our additional drilling and production results, geologic work we have completed, the BLM interim drilling policy and other regulations, we have developed an exploration and development plan for our Washakie Basin acreage. As the Washakie Basin encompasses a number of protected wildlife habitats and archeological sites, the BLM's interim drilling policy and other federal or state regulations play a significant role in determining the method in which we will develop our Washakie Basin acreage. Specifically, these rules:

- limit the number and spacing of wells drilled;
- determine the time and manner of construction of access roads, pipelines and other ancillary facilities; and
- require us to seek approval from federal and state agencies for the drilling of wells and construction of ancillary facilities.

For more information about these restrictions, see "Items 1 and 2—Business and Properties—Regulation."

Under the BLM interim drilling policy for the Washakie Basin, we plan to drill 165 gross wells in groups of wells or pods on 80 and 160 acre spacing. Nine of these pods will run from the northern to the southern border of our acreage and each pod will contain a central water injection well. It typically takes from four to ten days to drill these wells that have targeted depths between 1,200 to 4,500 feet. We drilled 38 coalbed methane wells and three water injection wells in 2001 and 2002. Based upon preliminary data from drilling, completion, production and test results, we believe that 34 of the 38 wells drilled are potentially productive. Based on our current acreage position and the drilling done to date, over 650 potential drilling locations have been identified. The amounts to be funded by us rather than our drilling programs depend on amounts actually raised in these programs in future years.

While there is currently limited pipeline infrastructure in the basin, there are three significant pipelines that run across or near our Washakie Basin acreage with total capacity of approximately 1.0

Bcf per day. We initially plan to transport our production through the existing pipeline running through the southern portion of our property that currently has a rated total capacity of 60 Mmcf per day and available capacity of up to 20 Mmcf per day. We believe this represents sufficient capacity for the production we expect to bring on line in 2003 and 2004. Over the longer term, we plan to build the gas gathering and transmission infrastructure to transport our production to the northern border of our acreage where there are several existing transportation options and several planned expansions. The timing of construction of a gas gathering and transmission system is contingent upon results. If only one pod in this area in the northern portion of our acreage has positive drilling results, a system to tie into existing infrastructure would cost approximately $250,000, which would likely be completed by the end of 2003. Positive drilling results in the majority of the northern half of the basin, might lead to construction and completion of such a system by the end of 2004, at cost estimated to be approximately $1.0 million. This area is compact in width and close to existing infrastructure. If the entire length of the Washakie Basin proves to be productive, an entirely new gathering system over a much larger area would need to be built to handle the potential volume of gas produced at a cost of approximately $10.0 million ($5.0 million net to us), which would likely require us to seek outside financing to construct such a system.

Our Other Natural Gas and Oil Activities

Approximately 87% of our total net proven reserves are located in two distinct areas:

- the Wilmington Field in the Los Angeles Basin of southern California; and
- in east Texas where we target the James Lime and Bossier formations.

Much of our drilling activities in these established natural gas and oil fields has and will continue to involve directional and horizontal drilling. While a conventional or vertical well is drilled downward in a straight line perpendicular to the surface of the earth, a horizontal well by means of such technologies as steerable motors and well-bore guidance telemetry is initially drilled perpendicular to the surface and turned to horizontal at the depth of the targeted formation with the wellbore path proceeding in a parallel path through the target formation. Multiple laterals, often drilled in a V-pattern and sometimes targeting different pay-zones, increase the well-bore footage in the pay-zone. Horizontal wells are drilled as either new wells or re-entry of an existing well. Horizontal wells, planned and drilled to target a specific formation, may be more effective in draining certain geologic formations than vertical wells, which is the case in our James Lime horizontal wells. Alternatively, as in the case of many of our Wilmington Field wells, because the surface location of the well does not correspond vertically with the location of the targeted oil reservoir, a directional well is drilled, linking the surface location to the target area.

Wilmington Field

Located in the heart of the Los Angeles Basin, the Wilmington Field is one of the largest fields in California and the United States, having produced over 2.5 billion barrels of oil since its discovery in the 1920's. Effective December 31, 1998, we acquired an undivided 47% working interest in a 1,440 gross acre area in the Wilmington Townlot Unit #1 located within the Wilmington Field. Our operations in the Wilmington Field are governed by a Joint Venture Agreement and Purchase and Sale Agreement dated May 1999 with our joint venture partner. Under the Joint Venture Agreement, Warren E & P initially acts as the operator, drilling and completing each well drilled in this area. However, upon commencement of production of these wells, our joint venture partner acts as the operator. Additionally, we pay 100% percent of the intangible drilling and completion costs and 50% of tangible costs and receive 95% of net revenues before payout of project costs and 80% after payout.

Our drilling activities in the Wilmington Field involve the use of the inverted five-spot method, which is one water injection well surrounded by four oil wells. The water injection well serves to increase pressure in the target geologic zone, moving oil away from the injector well and towards the oil wells. In 1999, we drilled three injector wells and four oil wells. Warren E & P conducted the drilling and completion operations and upon completion, our joint venture partner took over as operator of these wells. In late 1999, our drilling activities in this field were suspended due to litigation with our joint venture partner as described in "Item 3—Legal Proceedings" below. In this dispute, the Joint Venture Agreement and Purchase and Sale Agreement were upheld in a binding arbitration in February 2001 with the order issued in July 2001. Because new litigation was commenced in August 2001, we have been unable to recommence drilling activities, which are unlikely to begin again until the disputes with our joint venture partner are finally resolved. At December 31, 2002, we believe our estimated net proved reserves in this field were approximately 12 Mmbbls (71 Bcfe), 97% of which were proved undeveloped reserves. As of December 31, 2002, the average daily production from this field was 277 Bbls per day, net to Warren and its drilling programs. Oil produced in this field is marketed to Huntway Refinery at a posted price of approximately 80% of WTI Cushing plus a bonus of $0.25 or more per barrel.

East Texas—James Lime/Cotton Valley Formations

We hold approximately 52,344 gross (6,508 net) acres, where we are targeting the James Lime and Bossier formations in east Texas. The natural gas reservoirs in this formation are low porosity and low permeability carbonates and are naturally fractured. While geologic data indicates that there is significant gas in place in the James Lime formation, it is generally not well suited to development with traditional vertical wells. Vertical James Lime wells typically drain a very limited area in their immediate vicinity given the low porosity and low permeability of the formation. Horizontal wells, while more expensive to drill, have the potential to significantly increase the amount of gas production per well bore. In addition to horizontal drilling, many operators in the area are experimenting with hydraulic fracture stimulation that has initially shown positive results. The success of our operations in this field is dependent on our ability to control costs and on our engineering expertise, particularly the ability to accurately drill horizontal wells to specific geologic targets. Our operations in this field are conducted in conjunction with other independent operators and our working interests in the wells in this field range from 13% to 87.5%.

From May 2000, when we first began work in this James Lime field, until December 31, 2002, we drilled eight wells, of which seven are currently producing. Additionally, we have an average 25% interest in five Bossier wells in east Texas operated by Anadarko. We are the operator of 50% of the James Lime wells in the James Lime field. All of these James Lime wells were drilled laterally and range in depth from 6,000 to 9,000 feet and have total lengths ranging from 3,500 to 8,000 feet per lateral, with an average total cost to Warren of $1.3 million per well for its average 39% working interest. As of December 31, 2002, the production from these twelve wells was 2.5 Mmcf per day, of which 0.7 Mmcf was attributable to us and our drilling programs. At December 31, 2002, our total net proved reserves in this area attributable to Warren and its drilling programs was 1.3 Bcfe, of which 0.3 Bcfe was attributable to our net interest.

We began a divestiture program in 2002 to sell or otherwise dispose of substantially all wells and leases that do not meet our strategic focus within the Rocky Mountains and California. As a result, we intend to sell our interests in wells and leases in Texas, Oklahoma, New Mexico, Michigan and other non-core areas. We are currently in the process of selling our James Lime wells and leases owned by us and our drilling programs for approximately $2.5 million ($1.0 million net to us) to an industry partner in such fields. This transaction is scheduled to close on or about April 30, 2003, effective March 1, 2003.

Drilling Programs

Since 1992, we have sponsored and managed 30 privately placed drilling programs which have served as our principal funding source for exploration, development and production activities, and which enables investors to participate in our drilling activities. Most of the programs have been organized as limited partnerships. For each drilling program, we form a joint venture with either a limited partnership (between Warren and investors) or with investors who are direct working interest owners. These 30 programs have raised approximately $222 million. We act as the sole managing general partner of each drilling program. Investors in the limited partnership programs may purchase either limited or general partnership interests (typically general partnership interests), and receive their allocable share of income, expenses, cash distributions and tax benefits generated by their payment of 100% of the intangible drilling costs of the program's wells. Once drilling is completed for the drilling programs, the investors generally have the right to convert their general partnership interests into limited partnership interests. If a two-thirds majority of the partners' interests affirmatively consents, the form of the drilling program may be changed from a limited partnership to a limited liability company. As of March 19, 2003, thirteen drilling programs have voted to become limited liability companies.

Cost and Revenue Sharing at the Joint Venture Level. We enter into joint venture agreements with the drilling programs whereby we assign to the drilling programs 75% of our working interest and we retain the remaining 25% working interest, before payout, in properties to be drilled with funds provided by investors in the drilling programs, while we pay for the tangible equipment for our working interest. The drilling program investors pay intangible drilling costs to drill the wells and the drilling programs receive 75% of the net revenue from the wells before well payout (60% after payout). Warren pays 100% of the tangible completion costs on successful wells for 25% of the net revenue from the wells before payout (40% after payout).

Cost and Revenue Sharing within the Drilling Programs. The investor partners contribute 100% of the cash capital for 90% of the drilling program revenue from oil and gas production before payout (75% after payout). We assign 75% of our working interest in the leases to the drilling programs, and receive as our proportionate share 10% of the drilling program's net revenues before payout, subject to production subordination. Our revenue share at both the joint venture and drilling program levels is subject to a before payout production subordination clause for drilling programs formed prior to 1999 under which the drilling programs have received 100% of net revenue. We have forgone our share of cash flow from net revenues to the joint venture under provisions for us to do so until aggregate production for each program exceeds 30 Bbls of oil equivalent per day per well. For programs formed during and after 1999, we began receiving our 25% interest in July 2001 without subordination. Prior to such time, we voluntarily waived our 25% interest in such revenue to the joint venture. After payout, the subordination of our interest in production is terminated.

After Payout Revenue Sharing. After payout, or the point in time at which aggregate distributions to investors equal 100% of their original capital invested, the drilling program's share of the joint venture's revenues decreases from 75% to 60% and our share of revenue at the joint venture level increases from 25% to 40%. Thus we receive from our interests in the drilling programs a 55% after payout interest in the wells' revenues: 40% at the joint venture level, plus 25% of the drilling program's 60% after payout interest in the wells, or an additional 15% interest in the wells. To date, none of our drilling programs have reached payout status.

Interests in the programs have been sold through broker-dealers who are members of the National Association of Securities Dealers, Inc. In addition to a 5% commission paid by the drilling program, we pay or reimburse all costs and expenses associated with a program's organization, due diligence and offering, customarily ranging between 2% and 7% of investor subscriptions. In addition, in most of the programs offered prior to September 30, 2000, we issued warrants to the drilling programs and to broker-dealers in the selling group that entitled them to purchase shares of our common stock, all of which have been exercised or have expired.

As of December 31, 2002, investors in our drilling programs have received cash distributions ranging from below 10% for programs formed since 1998 to between 50% and 80% for seven programs formed in 1995 or earlier, excluding two programs formed in 1993 that have been liquidated. Currently, cash distributions to investors are made monthly. Our drilling programs have distributed to investors approximately $52.6 million through December 31, 2002. We plan to continue sponsoring drilling programs. To the extent they have funds available, our drilling programs will continue to participate on a pro rata basis in all of our drilling activities.

We typically contract with the drilling programs to conduct drilling services for them on a turnkey fixed-price basis, generally subject to a profit limitation ranging from 25% to 37.5%. Nine of the 30 programs have no limitations on turnkey profits. Pursuant to these turnkey drilling agreements, we are paid a fixed price for the drilling of each well and if the actual costs we incur exceed the fixed contract price in the agreement, we pay these costs without any recourse to the drilling program. If the actual costs incurred by us are less than the fixed price we receive, we retain the excess.

Although generally we enter into drilling subcontracts primarily with unrelated parties to drill wells covered by our turnkey agreements with affiliated partnerships, from time to time field services have been provided by our subsidiary Pinnacle. The portion of Pinnacle's drilling activities performed for affiliated partnerships and joint ventures was 5% during 2001 and 2000 and was negligible in 2002. Pinnacle was sold in February 2002.

In addition, we have marketing agreements with most of the drilling programs under which we purchase oil and gas produced by affiliated joint ventures and partnerships at current field prices, which we then transport and market to third parties. We construct our own gas gathering and transportation lines that connect wells owned by joint ventures and partnerships to the pipelines owned by gas transportation companies. We enter into transportation contracts with these companies and sales contracts for the sale of oil and gas to the third party purchasers.

We are entitled to receive a $350 monthly management fee per well to cover ongoing administrative costs, plus reimbursement of out-of-pocket expenses. This management fee has been waived since inception of the programs but commenced upon the distribution of January 2002 production. Warren E & P, our wholly owned subsidiary, also serves as the operator of the wells under a standard form of joint operating agreement, under which it is entitled to operating fees of approximately $300 per month per well.

We, together with other joint venture working interest owners and investors holding interests as working interest general partners, are jointly and severally liable for each drilling program's debts, obligations and liabilities. We maintain a $50 million per incident limit casualty insurance policy covering all the programs collectively and indemnify each program and all investors against any liability caused by our gross negligence, willful misconduct, bad faith, fraud or breach of fiduciary duty, or for any obligation relating to casualty losses that exceed our insurance limits and the program's assets.

As managing general partner, we manage and operate the business of each of the partnerships on a day-to-day basis. However, the prior written consent (ranging from 51% to 100%) of investor partners is required in matters such as raising additional capital, borrowing money on behalf of the partnerships, entering into certain agreements with affiliates of Warren, the sale, conveyance, assignment or pledge of substantially all of the partnerships' assets; or the rollup or merger of the partnerships into or with any other entity; confess a judgment or make an assignment of partnership property for the benefit of creditors or other similar actions. Additionally, the partners can remove us as the managing general partner at any time by a vote of more than 66.7% of all partners.

Under the terms of our drilling programs, we generally retain the right to engage in natural gas and oil exploration and production through other entities and for our own account. From time to time, we may engage in transactions that are in competition with our partners or co-venturers or be faced with decisions that could have conflicting impacts on our businesses. Involvement in these different transactions may limit the time we have available to attend to any particular transaction. It may also adversely affect the funds we have available to service our financial commitments to partners or co-venturers. We may also render certain services or provide goods for our drilling programs at fees that are competitive with the market price.

Eighteen of our drilling programs contained a buy/sell agreement, pursuant to which an investor partner may tender his interest commencing seven years after the program's closing for repurchase by the program or other investors. If the programs or other investors do not purchase the withdrawing investor's interest, we agree to repurchase, directly or indirectly through a third party, the investor's interest in the drilling program at fair market value, as determined by an independent petroleum engineer at the time of repurchase or a formula repurchase price for drilling programs formed in 1997 and prior. For example, the 1995 drilling program investors were first able to exercise their repurchase rights commencing in January 2003 based on a repurchase price equal to an investor's original capital invested in the program, reduced by the greater of either total distributions made to the investor to the repurchase date or by 10% of the original subscription price for each $1.00 the oil price is below $13.00 per Bbl at the time of repurchase, with adjustment for the change in the Consumer Price Index since the date of initial investment. If the repurchase price were calculated at December 31, 2002, an investor in an 1995 program would be entitled to sell his interest for approximately between 22% and 49% of his original investment. For programs formed after 1997, the repurchase price cannot exceed an investor's allocable share of the net present value of estimated proved reserves as determined by an independent petroleum engineer. The buy/sell feature was eliminated for programs beginning after 2001.

In late 2002, each of the thirteen drilling programs formed from 1994 through 1997 commenced a vote solicitation of their partners (the "Vote Solicitation") to: (i) obtain the requisite 2/3rds affirmative vote of their respective partners to convert their drilling program from a Delaware limited partnership to a Delaware limited liability company (an "LLC") wherein all LLC members would have limited liability, including Warren, and (ii) allow partners to select whether they wanted to be (a) a standard member in the LLC with substantially the same rights and obligations that they had as partners in their respective drilling fund, or (b) a preferred member in the LLC having certain preferential rights ("Preferred Member") by consenting to Warren's contribution of additional capital to the LLC upon conversion (the "Recapitalization") in the form of its unregistered 8% cumulative convertible preferred shares ("Preferred Shares") in an amount equal to between 110% to 120% of the potential repurchase price of consenting partners' interests calculated as of December 31, 2002. For its additional capital contribution, Warren received additional standard membership interests in the LLC and was specially allocated a prorata interest as a standard member in the wells and oil and gas leases formerly allocable to the partners who elected to become Preferred Members. Election by a partner to become a Preferred Member terminated their repurchase rights under the original buy/sell agreements. At December 31, 2002, six of the thirteen programs obtained the requisite votes to convert to LLCs and on average 71.3% of the program members elected to become Preferred Members in their LLC. As a result under the Recapitalization, Warren issued 1,342,960 Preferred Shares in the aggregate to the six LLCs as an additional capital contribution and received its prorata share of additional standard membership interests in the LLCs. The Preferred Shares are restricted shares and neither the Preferred Shares, nor the common stock into which they may be converted, can be transferred or distributed by the LLC without compliance with applicable federal and state securities laws.

Additionally, as of March 19, 2003, all thirteen drilling programs had received the necessary 2/3rds affirmative votes necessary to convert to LLCs and on average 72% of the program members elected to become Preferred Members. As a result, as of March 19, 2003, Warren will issue in the aggregate 3,212,317 shares of Preferred Stock on or around March 31, 2003 as part of the next closing, as additional capital to the thirteen LLCs and received its prorata share of additional standard membership interests in the LLCs.

Natural Gas and Oil Reserves

The following table presents our estimated proved natural gas and oil reserves and the PV-10 value of our interests in net reserves in producing properties as of December 31, 2000, 2001 and 2002 based on reserve reports prepared by Williamson Petroleum Consultants, Inc., Midland, Texas, independent petroleum engineers. The PV-10 values shown in the table are not intended to represent the current market value of the estimated oil and natural gas reserves we own. For further information concerning the PV-10 values of these proved reserves, please read Note N of the notes to our consolidated financial statements.

A significant portion of our proved reserves has been accumulated through our interests in the drilling programs for which we serve as managing general partner. The estimates of future net cash flows and their present values, based on period end prices, assume that certain of the drilling programs in which we own interests will achieve payout status in the future. As of December 31, 2002, none of the active 30 drilling programs managed by us had achieved payout status. As of July 1, 2001, we began receiving our before payout share of production, typically 25%, from all programs formed in 1999. We began receiving our before payout share of production in the first quarter of 2002 for all programs formed during 2000.

	Years Ended December 31,		
	2000	2001	2002
Estimated Proved Natural Gas and Oil Reserves:			
Net natural gas reserves (Bcf):			
Proved developed	8.034	1.648	4.544
Proved undeveloped	3.482	0.847	3.959
Total	11.516	2.495	8.503
Net oil reserves (Bcfe):			
Proved developed	1.456	0.049	2.423
Proved undeveloped	69.164	50.821	71.521
Total	70.620	50.870	73.944
Total Proved Natural Gas & Oil Reserves (Bcfe)	82.136	53.365	82.447
Estimated Present Value of Proved Reserves:			
PV-10 Value (discounted at 10% per annum) (in thousands)			
Proved developed	$ 28,435	$ 1,246	$ 10,041
Proved undeveloped	89,392	19,236	$103,913
Total	$117,827	$20,482	$113,954
Standardized Measure of Discounted Future net Cash Flows	$ 89,096	$19,512	$ 71,418
Prices Used in Calculating End of Year Proved Reserves:			
Oil (per Bbl)	$ 20.37	$ 13.87	$ 27.15
Natural Gas (per Mcf)	8.53	1.76	3.36

There are numerous uncertainties in estimating quantities of proved reserves and in projecting future rates of production and the timing of development expenditures, including many factors beyond our control. The reserve data set forth in this registration statement are only estimates. Although we believe these estimates to be reasonable, reserve estimates are imprecise and may be expected to change as additional information becomes available. Estimates of natural gas and oil reserves, of necessity, are projections based on engineering data and there are uncertainties inherent in the interpretation of this data, as well as the projection of future rates of production and the timing of development expenditures. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be exactly measured. Therefore, estimates of the economically recoverable quantities of natural gas and oil attributable to any particular group of properties, classifications of the reserves based on risk of recovery and the estimates are a function of the quality of available data and of engineering and geological interpretation and judgment and the future net cash flows expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. There also can be no assurance that the reserves set forth herein will ultimately be produced or that the proved undeveloped reserves will be developed within the periods anticipated. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material. In addition, the estimates of future net revenues from our proved reserves and the present value thereof are based upon certain assumptions about future production levels, prices and costs that may not be correct.

We emphasize, with respect to the estimates prepared by independent petroleum engineers, that PV-10 value should not be construed as representative of the fair market value of our proved natural gas and oil properties since discounted future net cash flows are based upon projected cash flows which do not provide for changes in natural gas and oil prices or for the escalation of expenses and capital costs. The meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they are based. Actual future prices and costs may differ materially from those estimated. You are cautioned not to place undue reliance on the reserve data included in this registration statement. Under SEC guidelines, estimates of the PV-10 value of proved reserves must be made using oil and gas sales prices at the date for the valuation, which prices are held constant throughout the life of the properties. Commodity prices were unusually high at year-end 2000, especially gas prices, and have declined since that time. NYMEX pricing for natural gas ranged from $1.91 to $5.34 per Mmbtu during 2002 and from $1.91 to $9.82 per Mmbtu during 2001. NYMEX pricing for oil ranged from $17.97 to $32.72 per Bbl during 2002 and from $17.45 to $32.19 per Bbl during 2001.

Productive Wells

The following table sets forth our gross and net productive wells as of December 31, 2002:

	Natural Gas Wells		Oil Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
California	—	—	34	27.3	34	27.3
New Mexico	27	11.2	2	0.8	29	12.0
Texas	12	3.0	—	—	12	3.0
Wyoming	121	32.8	4	1.1	125	33.9
Other	1	0.7	2	1.4	3	2.1
Total	161	47.7	42	30.6	203	78.3

Gross wells represent all wells in which we have an interest. Net wells represent the total of our fractional undivided working interest in those wells.

Drilling Activity

The following table sets forth our drilling activities for the three years 2000, 2001 and 2002:

	Years Ended December 31,					
	2000		2001		2002	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells(1)						
Productive(2)	1	0.3	6	2.8	—	—
Nonproductive(3)	2	0.7	20	9.5	—	—
Development Wells(1)						
Productive(2)	69	23.7	10	4.7	29	20.6
Nonproductive(3)	—	—	—	—	2	1.4
TOTAL	72	24.7	36	17.0	31	22.0

(1) An exploratory well is a well drilled either in search of a new, as yet undiscovered oil or gas reservoir or to greatly extend the known limits of a previously discovered reservoir. A development well is a well drilled within the presently proved productive area of an oil or gas reservoir, as indicated by reasonable interpretation of available data, with the objective of completing in that reservoir.

(2) A productive well is an exploratory or development well found to be capable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

(3) A nonproductive well is an exploratory or development well that is not a producing well.

Natural Gas and Oil Acreage

The following table sets forth our acreage position as of December 31, 2002:

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
California	1,128	407	312	113	1,440	520
New Mexico	6,925	530	3,562	421	10,487	951
Texas	8,259	1,009	44,085	5,498	52,344	6,507
Wyoming	11,630	3,790	219,993	123,838	231,623	127,628
Other	1,560	614	3,575	1,406	5,135	2,020
Total	29,502	6,350	271,527	131,276	301,029	137,626

Production Volumes, Sales Prices and Production Costs

The following table summarizes our net natural gas and oil production volumes, our average sales prices and expenses for the periods indicated. Our volumes are attributable to our direct interests in producing properties and the production we are allocated from our 1999 and subsequent drilling programs where we typically receive 25% of the production from such programs. For these purposes, our net production will be production that is owned by us either directly or indirectly through our drilling programs, after deducting royalty, limited partner and other similar interests. The lease operating, depreciation, depletion and amortization expenses shown are related only to our net production. The majority of our lease operating expense is from workovers and other operating costs paid by us on behalf of our drilling programs and do not represent lease operating expense related to our net production.

	Years Ended December 31,		
	2000	2001	2002
Production:			
Natural Gas (Mmcf)	29.9	32.6	54.8
Oil (Mbbls)	3.2	2.3	4.3
Total Equivalents (Mmcfe)	49.1	46.7	80.3
Average Sales Price Per Unit:			
Natural Gas Without Hedge ($ per Mcf)	$ 3.33	$ 3.07	$ 1.90
Hedge Loss	(0.07)	(0.24)	(0.00)
Actual Natural Gas	3.26	2.83	1.90
Oil ($ per Bbl)	$26.26	$16.74	$20.84
Total Equivalents ($ per Mcfe)	$ 3.70	$ 2.82	$ 2.40
Expenses (per Mcfe):			
Lease Operating Expense (For Our Net Production)	$ 1.46	$ 1.50	$ 1.50

Purchasers and Marketing

We sell our oil and natural gas production and that of our drilling programs to various purchasers in the areas where the oil and natural gas is produced. The oil is sold to crude oil purchasers at storage tankage that we own located on the lease of property. The natural gas is sold into pipelines and re-marketed or used by various gas purchasers. We are currently able to sell all of the oil and natural gas produced on our behalf and that of our drilling programs. Substantially all of this oil and gas is sold under monthly contracts that allow for periodic adjustments in pricing according to market demands. Approximately 66% of Warren's gas production was subject to a firm commitment contract for transportation space (but not sales) with Williston Basin Interstate relating to its LX-Bar lease for 6 Mmcf per day, which will terminate in October 2006. The price for gas provided is the market price at the time. Additionally, we have a firm commitment contract relating to our Piper Federal lease covering requirements for us to deliver 2.5 Mmcf per day. The maximum penalty for any deficiency below 90% of cumulative contracted volumes would be $0.42 per Mcf. This contract terminates on December 31, 2004. The marketing of oil and natural gas can be affected by factors beyond our control, the effects of which cannot be predicted. For more information about the risks to our business posed by our marketing activities see "Item 7-Management's Discussion and Analysis of Financial Condition and Results of Operation-Risk Factors-The marketability of our production is dependent upon factors over which we have no control."

For the year ended December 31, 2002, the largest purchasers for our production and that of our drilling programs included Tenaska Marketing Ventures, Western Gas Resources, Inc. and Huntway Refining Company, which accounted for 30%, 8% and 16%, respectively, of the oil and gas sold by us and our drilling programs. We do not believe, however, that the loss of any of these purchasers would have a material adverse effect on our operations. Our contracts with Tenaska and Western have minimum deliverability requirements. Our firm commitment contracts have ranged from approximately 6,000 to 9,000 Mcf per day.

We compete with a number of other potential purchasers of natural gas and oil leases and producing properties, many of which have greater financial resources than we do. In general, the bidding for natural gas and oil leases has become particularly intense in the Powder River and Washakie Basins with bidders evaluating potential acquisitions with varying product pricing parameters and other criteria that result in widely divergent bid prices. The presence of bidders willing to pay prices higher than are supported by our evaluation criteria could further limit our ability to acquire natural gas and oil leases. In addition, low or uncertain prices for properties can cause potential sellers to withhold or withdraw properties from the market. In this environment, we cannot guarantee that there will be a sufficient number of suitable natural gas and oil leases available for acquisition or that we can sell natural gas and oil leases or obtain financing for, or participants to join in, the development of prospects.

Our Service and Operational Activities

Our drilling, completion, production and land operations are conducted, managed and supervised for us and our drilling programs through Warren E & P, our wholly owned subsidiary. After a long-term joint venture relationship with Warren E & P that began in 1990, we acquired Warren E & P on September 1, 2000. See "Item 13-Certain Relationships and Related Transactions." Through Warren E & P, we employ three petroleum engineers, several drilling supervisors, landmen and administrative personnel, as well as field supervisors. Warren E & P also employs one geologist on a contract basis. Pursuant to joint venture agreements, Warren E & P has been the contract operator for the majority of our wells for the past ten years, and is the operator of 65% of the wells in which we and our drilling programs had interests as of December 31, 2002.

We previously provided drilling and certain field services through Pinnacle, another wholly owned subsidiary, the assets of which were sold as of February 14, 2002. At the time of sale, Pinnacle employed approximately 45 rig hands and owned eight operational workover rigs, one operational horizontal/recompletion rig, one operational swabbing unit and one non-operational swabbing unit. Two workover rigs were located in Beeville, Texas and the rest of Pinnacle's equipment was based in Artesia, New Mexico. During 2002 and 2001, 1% to 5% of Pinnacle's operations were in support of Warren E & P, the balance was for third parties on a variety of contract terms, including hourly, daily or per job rates.

Regulations

General

Our business is affected by numerous laws and regulations, including energy, environmental, conservation, tax and other laws and regulations relating to the energy industry. Changes in any of these laws and regulations could have a material adverse effect on our business. In view of the many uncertainties with respect to current and future laws and regulations, including their applicability to us, we cannot predict the overall effect of such laws and regulations on our future operations.

We believe that our operations comply in all material respects with applicable laws and regulations and that the existence and enforcement of such laws and regulations have no more restrictive an effect on our operations than on other similar companies in the energy industry. Warren anticipates no material estimated capital expenditures to comply with federal and state environmental requirements. To date, state-wide reclamation bonds and our $50 million casualty and environmental insurance have been adequate to meet such requirements. Additionally, we have posted a $3.0 million US Treasury Bond as collateral for a $4.0 million reclamation bond for the Wilmington Field. The following discussion contains summaries of certain laws and regulations and is qualified in its entirety by the foregoing.

Proposals and proceedings that might affect the oil and gas industry are pending before Congress, the Federal Energy Regulatory Commission, or "FERC", the Minerals Management Service, or "MMS", state legislatures and commissions and the courts. We cannot predict when or whether any such proposals may become effective. In the past, the natural gas industry has been heavily regulated. There is no assurance that the regulatory approach currently pursued by various agencies will continue indefinitely. Notwithstanding the foregoing, we do not anticipate that compliance with existing federal, state and local laws, rules and regulations will have a material or significantly adverse effect upon our capital expenditures, earnings or competitive position. No material portion of our business is subject to re-negotiation of profits or termination of contracts or subcontracts at the election of the federal government.

Federal Regulation of Sales and Transportation of Natural Gas

Historically, the transportation and sale of natural gas in interstate commerce has been regulated under several laws enacted by Congress and the regulations passed under these laws by FERC. Our sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms of access to pipeline transportation are subject to extensive federal and state regulation. From 1985 to the present, several major regulatory changes have been implemented by Congress and FERC that affect the economics of natural gas production, transportation and sales. In addition, FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to FERC's jurisdiction. These initiatives may also affect the intrastate transportation of gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry.

The ultimate impact of the complex rules and regulations issued by FERC cannot be predicted. In addition, many aspects of these regulatory developments have not become final but are still pending judicial and final FERC decisions. We cannot predict what further action FERC will take on these matters. Some of FERC's more recent proposals may, however, adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any action taken materially differently than other natural gas producers, gatherers and marketers with whom we compete.

Federal Regulation of Sales and Transportation of Crude Oil

Our sales of crude oil, condensate and natural gas liquids are currently not regulated and are made at market prices. In a number of instances, however, the ability to transport and sell such products are dependent on pipelines whose rates and terms of service are subject to FERC jurisdiction under the Interstate Commerce Act. Some of the regulations implemented by FERC in recent years could result in an increase in the cost of transportation service on certain petroleum pipelines. However, we do not believe that these regulations affect us any differently than other producers of these products.

Operations on Federal Oil and Gas Leases

We conduct a sizeable portion of our operations on federal oil and natural gas leases which are administered by the MMS. Federal leases contain relatively standard terms and require compliance with detailed MMS regulations and orders, which are subject to change. Under certain circumstances, the MMS may require any of our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition, cash flows and operations. The MMS issued a final rule that amended its regulations governing the valuation of oil produced from federal leases. This new rule, which became effective June 1, 2000, provides that the MMS will collect royalties based on the market value of oil produced from federal leases. The lawfulness of the new rule has been challenged in federal court. We cannot predict whether this new rule will be upheld in federal court, nor can we predict whether the MMS will take further action on this matter. However, we do not believe that this new rule will affect us any differently than other producers and marketers of oil.

State Regulation

Our operations are also subject to regulation at the state and in some cases, county, municipal and local governmental levels. Such regulation includes requiring permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandonment of wells and the disposal of fluids used and produced in connection with operations. Our operations are also subject to various conservation laws and regulations pertaining to the size of drilling and spacing units or proration units and the unitization or pooling of oil and gas properties.

In addition, state conservation laws, which frequently establish maximum rates of production from oil and gas wells, generally prohibit the venting or flaring of gas and impose certain requirements regarding the rates of production. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements, but, except as noted above, does not generally entail rate regulation. These regulatory burdens may affect profitability, but we are unable to predict the future cost or impact of complying with such regulations.

Environmental Matters

General

We are subject to extensive federal, state and local environmental laws and regulations that restrict or limit our business activities for purposes of protecting human health and the environment. Compliance with the multitude of regulations issued by federal, state, and local administrative agencies can be burdensome and costly. State environmental regulatory programs are generally very similar to the corresponding federal environmental regulatory programs, and federal environmental regulatory programs are often delegated to the states.

Our oil and gas exploration and production operations are subject to state and/or federal solid waste regulations that govern the storage, treatment, and disposal of solid and hazardous wastes. However, much of the solid waste generated by our oil and gas exploration and production activities is exempt from regulation as hazardous waste under federal, and many state, regulatory programs. To the extent our operations generate solid waste, such waste is generally subject to state regulations. We have not experienced difficulty in complying with applicable solid waste regulations in the areas in which we operate.

In addition to oil and gas, our production operations generate produced water as a waste material. This water can sometimes be disposed of by discharging it under discharge permits issued pursuant to the Clean Water Act, or an equivalent state program. We have not experienced difficulties in obtaining discharge permits in areas where such permits are issued. Another common method of produced water disposal is subsurface injection in disposal wells. Such disposal wells are permitted under the Safe Drinking Water Act, or an equivalent state regulatory program. The drilling, completion, and operation of produced water disposal wells are integral to oil and gas operations. We already operate produced water disposal wells, particularly in association with our coalbed methane production operations. We are experienced in these activities and are able to perform these activities in a cost-effective manner.

Air emissions from some of our equipment, such as gas compressors, are potentially subject to regulations under the Clean Air Act, or equivalent state regulatory programs. To the extent that our air emissions are regulated, they are generally regulated by permits issued by state regulatory agencies. We have not encountered difficulties in obtaining air permits, where needed.

Some of our exploration and production activities occur on federal leases. This is particularly true of our coalbed methane operations. Exploration and production operations on federal leases are generally performed in accordance with a record of decision issued by the BLM after performance of an environmental impact study. A record of decision typically includes environmental and land use provisions that restrict and limit exploration and production activities on federal leases. Much of our coalbed methane operations are subject to records of decision and we have not experienced any material difficulty in complying with their terms and conditions. Nor do we anticipate any material adverse effect on our operations from terms and conditions in records of decision that are pending from the BLM.

In the event that spills or releases of crude oil or produced water occur, we would be subject to spill notification and response regulations under the Clean Water Act, or equivalent state regulatory programs. Depending on the nature and location of our operations, we may also be required to prepare spill response plans under the Clean Water Act, or equivalent state regulatory programs.

Failure to comply with such regulations may result in the imposition of substantial administrative, civil, or criminal penalties, or restrict or prohibit our desired business activities. Environmental laws and regulations impose liability, sometimes strict liability, for environmental cleanup costs and natural resource damages. Other environmental laws and regulations may delay or prohibit exploration and production activities in environmentally sensitive areas or impose additional costs on these activities.

We believe that we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on us. Costs associated with responding to a major spill of crude oil or produced water, or costs associated with remediation of environmental contamination, are the most likely occurrences which could result in a material adverse impact on our capital expenditures, earnings, or competitive position. We are not currently liable for any such environmental cleanup costs, and we operate our producing properties in a prudent manner in order to avoid or minimize such liabilities.

In addition, changes in applicable federal, state and local environmental laws and regulations have the potential to adversely affect our operations. In this regard, our coalbed methane drilling and production operations are subject to ongoing BLM oversight and recurring BLM approvals and could be affected by changes in BLM regulations or policies. However, we are not aware of any pending changes in state or federal environmental statutes or regulations that would have a material adverse impact on our operations.

We anticipate that total maximum daily load water quality standards may be promulgated within five years for surface water bodies in areas where we operate, including the Powder River Basin of Wyoming. However, we do not expect that any total maximum daily load regulations, or standards promulgated in any area where we operate to result in a material increase in our produced water disposal costs, as we already inject much of our produced water in disposal wells, and would be able to cost-effectively drill and operate additional disposal wells as needed.

Coalbed Methane Operations

The majority of our production is from coalbed methane operations which generate water and air discharges that are subject to significant regulatory control. Naturally occurring groundwater is typically produced by our coalbed methane production operations. This produced water is disposed of by re-injection into the subsurface through disposal wells, discharge to the surface, or in evaporation ponds. Whichever disposal method is used, produced water must be disposed of in compliance with permits issued by federal and state regulatory agencies, and in compliance with applicable federal, state and local environmental regulations. To date, we have been able to obtain necessary surface discharge or disposal well permits and we have been able to discharge produced water and operate our produced water disposal wells in substantial compliance with our permits and applicable federal, state and local laws and regulations without undue cost or burden to our business activities.

Our coalbed methane operations involve the use of gas-fired compressors to transport gas which we produced. Emissions of nitrogen oxides and other combustion by-products from individual compressors or multiple compressors at one location may be great enough to subject the compressors to federal and state air quality requirements for pre-construction and operating permits. To date, we have not experienced significant delays or problems in obtaining the required air permits and have been able to operate these compressors in substantial compliance with our permits and applicable federal, state and local laws and regulations without undue cost or burden to our business activities. Another air emission associated with our coalbed methane operations that may be subject to regulation and permitting requirements is particulate matter resulting from construction activities and vehicle traffic. To date, we have not experienced any difficulty complying with environmental requirements related to particulate matter.

Powder River Basin

Wyoming. Drilling and production operations on our Powder River Basin leases in Wyoming are subject to environmental rules, requirements and permits issued by federal, state and local regulatory agencies, including the BLM and the Wyoming Department of Environmental Quality, or "DEQ." The BLM has imposed environmental limitations and conditions on coalbed methane drilling, production and related construction activities on federal leases in certain specific areas of the Powder River Basin. These conditions and requirements are imposed through a record of decision issued pursuant to an environmental impact statement. The BLM may also impose site-specific conditions on development activities, such as drilling and the construction of right-of-ways, before it approves required applications for permits to drill and plans of development. We believe that we have operated our Wyoming Powder River Basin federal leases in substantial compliance with the BLM's current requirements. The BLM is currently developing an environmental impact statement, or "EIS," for oil and gas development in the Powder River Basin of Wyoming. This Powder River Basin EIS is expected to be completed, and a record of decision issued, by May of 2003. At the present time, we have no ability to determine whether this EIS or future BLM site-specific approvals will result in conditions or requirements more stringent than, or materially different from, current BLM regulation of Powder River Basin coalbed methane operations in Wyoming.

Our Wyoming Powder River Basin coalbed methane production operations are also subject to Wyoming DEQ environmental regulations and permit requirements. Permits required from the Wyoming DEQ include air emission and produced water discharge permits. To date, we have not experienced any difficulty in obtaining air permits from the Wyoming DEQ. Injection wells are used to dispose of produced water when surface discharge permits cannot be obtained from the Wyoming DEQ. We have three permitted injection wells for our Wyoming Powder River Basin operations. We anticipate the need to permit, drill and operate additional injection wells in the event additional subsurface disposal capacity is needed.

Washakie Basin

The Washakie Basin is located in Wyoming and is currently the subject of the Atlantic Rim EIS being developed by BLM. The initial, or scoping, phase of the Atlantic Rim EIS covering our coalbed methane leases in the Washakie Basin is currently under way. Completion of the environmental impact statement and issuance of a record of decision is currently expected by the end of 2004.

The BLM has issued an interim drilling policy allowing some coalbed methane drilling and production activity in the Atlantic Rim project area pending completion of the EIS. The interim drilling policy authorizes drilling, completing, and producing no more than 200 wells until completion of the Atlantic Rim EIS. We have been allocated approximately 165 gross wells of the 200 authorized wells. The interim policy requires the wells to be drilled in nine pods of no more than 24 wells per pod. A pod is defined as two or more production wells with supporting infrastructure, such as access roads, injection wells, product pipelines, water pipelines, power lines and other necessary ancillary facilities. The Atlantic Rim project area contains federally designated threatened and endangered species and two wildlife habitat areas that have been designated as areas of critical environmental concern. Sensitive areas such as critical habitat and archeological sites must be avoided in constructing the pods. Federal and non-federal leases in the Atlantic Rim project area are subject to the 200 well limit. To date, we have received BLM and state approval of drilling permits for twelve wells, and approval of right-of-ways for four pods.

The BLM may modify the interim drilling policy at any time and the policy, as with any agency decision, is subject to challenge by interested parties. The interim policy requires an environmental assessment for each of the nine pods. Public comment is allowed on each environmental assessment, and BLM approval of each environmental assessment must be obtained before pod construction can commence. In addition, many of the restrictions, conditions and limitations on our drilling, production and construction activities in the Washakie Basin will be specified by the BLM in the final Atlantic Rim record of decision. Finally, conditions and restrictions on drilling, production and construction activities may be imposed through site-specific BLM approvals required for applications for permits to drill and plans of development. As a result, such development activities will remain contingent on BLM approval for much of the project life.

Our Washakie Basin coalbed methane production operations are also subject to DEQ environmental regulations and permit requirements. Permits required from the Wyoming DEQ include air emission and produced water discharge permits. To date, we have not experienced any difficulties in obtaining any air permits needed for our Washakie Basin operations from the Wyoming DEQ. Produced water disposal will be limited to subsurface injection in the portion of the Washakie Basin within the Colorado River drainage area. We have received permits for eight produced water injection wells in the Atlantic Rim project area. Should additional subsurface disposal capacity be needed, we will need to obtain permits for additional injection wells. Surface discharge of water remains an option in those portions of the basin outside of the Colorado River drainage area.

Wilmington Field

The Wilmington Field is located in the Los Angeles metropolitan area in California. Under the joint venture agreement governing operations in this field, we are the operator for drilling and completion activities and our joint venture partner is the operator for production activities. This field is located in a mixed light industrial and residential area near the Port of Los Angeles. Field activities include drilling wells to develop our lease acreage and operating a waterflood to maximize crude oil production.

Stringent environmental regulations, restrictive permit conditions and the possibility of permit denials from a multiplicity of state, regional and local regulatory agencies may inhibit or add cost to future Wilmington Field development activities. Despite prudent operation and preventative measures, drilling and waterflooding production operations may result in spills and other accidental releases of produced and injection fluids. Remediation and associated costs from a release of produced fluids in an urban environment may also be significant. This potential liability is accentuated by the location of our Wilmington Field leases in California and in an urban setting, including proximity to residential areas. To date and to our knowledge, there are no environmentally related lawsuits or other third-party claims or complaints pending against us relating to our interests or activities in the Wilmington Field.

East Texas

We have a significant acreage position in the James Lime formations of east Texas. Currently, these leases are relatively undeveloped and should be sold shortly. As a result, we believe the current potential for environmental liability associated with these properties is lower than for other properties that are to be actively developed.

Operating Hazards And Insurance

The oil and natural gas business involves a variety of operating risks, including fires, explosions, blowouts, environmental hazards and other potential events which can adversely affect our operations. Any of these problems could adversely affect our ability to conduct operations and cause us to incur substantial losses. Such losses could reduce or eliminate the funds available for exploration, exploitation or leasehold acquisitions or result in loss of properties.

In accordance with industry practice, we maintain insurance against some, but not all, potential risks and losses. We do not carry business interruption insurance. For some risks, we may elect not to obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable at a reasonable cost. If a significant accident or other event occurs and is not fully covered by insurance, it could adversely affect us.

Title to Properties

In most situations, as is customary in the oil and gas industry, only a preliminary title examination is conducted at the time we acquire oil and gas leases covering properties for possible drilling operations. Prior to the commencement of drilling operations, a more complete title examination of the drill site tract often is conducted by independent attorneys. Once production from a given well is established, we usually prepare a division order title report indicating the proper parties and percentages for payment of production proceeds, including royalties. The level of title examination often differs from property to property. For example, we acquired our interest in the Wilmington Field with no warranty of title at all, no representation as to the percentage working or net revenue interest we acquired and no title opinion as to the acquired interest. On a gross acreage basis we estimate that no complete title search has been conducted on approximately 5.0% of such gross acreage, which represents approximately 85% of our year end 2002 net proved reserves. Our properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens which we believe do not materially interfere with the use of or affect the value of our properties.

Employees

At December 31, 2002, we had 34 full-time employees. We believe that our relationships with our employees are good. None of our employees are covered by a collective bargaining agreement. From time to time, we use the services of independent consultants and contractors to perform various professional services, particularly in the areas of geological, permitting and environmental assessment. Independent contractors often perform field and on-site production operation services for us, including pumping, maintenance, dispatching, inspection and testing.

Facilities

Our principal executive offices are located at 489 Fifth Avenue, 32^{nd} Floor, New York, New York 10017, and our telephone number is (212) 697-9660. We lease approximately 4,097 square feet of office space for our New York office under a lease that expires in 2008. Our oil and gas administrative office in Albuquerque, New Mexico occupies 3,000 square feet under a lease expiring May 31, 2003, which will not be renewed. Our Rocky Mountain operations are headquartered in a 3,150 square foot space in Gillette, Wyoming. Commencing in April 2003, our oil and gas administration and operations headquarters will be relocated to a 3,750 square foot space in Casper, Wyoming under a lease (currently being negotiated) that expires on March 31, 2006. Warren E & P owned a ranch that was sold in 2002 with a 3,000 square foot field office in Beeville, Texas. We believe that suitable additional space to accommodate our anticipated growth will be available in the future on commercially reasonable terms.

Available Information

Our Internet address is www.warrenresourcesinc.com. We make available, free of charge through our website, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, as soon as reasonably practicable after such documents are electronically filed with, or furnished to, the SEC.

Glossary of Abbreviations and Terms

The following are abbreviations and definitions of certain terms commonly used in the oil and gas industry and this registration statement:

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

Bcf. One billion cubic feet of natural gas at standard atmospheric conditions.

Bcfe. One billion cubic feet equivalent of natural gas, calculated by converting oil to equivalent Mcf at a ratio of 6 Mcf to 1 Bbl of oil.

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

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

Exploitation. The continuing development of a known producing formation in a previously discovered field. To make complete or maximize the ultimate recovery of oil or natural gas from the field by work including development wells, secondary recovery equipment or other suitable processes and technology.

Exploration. The search for natural accumulations of oil and natural gas by any geological, geophysical or other suitable means.

Farmout or Farmin. An agreement where the owner of a working interest in an oil and gas lease assigns the working interest or a portion thereof to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a farmin while the interest transferred by the assignor is a farmout.

Fracturing. The technique of improving a well's production or injection rates by pumping a mixture of fluids into the formation and rupturing the rock, creating an artificial channel. As part of this technique, sand or other material may also be injected into the formation to keep the channel open, so that fluids or gases may more easily flow through the formation.

Gross Acres. The total acres in which we own any amount of working interest.

Gross Wells. The total number of producing wells in which we own any amount of working interest.

Horizontal Drilling. A drilling operation in which a portion of the well is drilled horizontally within a productive or potentially productive formation. This operation usually yields a well which has the ability to produce higher volumes than a vertical well drilled in the same formation.

Injection Well or Injector. A well which is used to place liquids or gases into the producing zone during secondary/tertiary recovery operations to assist in maintaining reservoir pressure and enhancing recoveries from the field.

Intangible Drilling Costs. Expenditures made for wages, fuel, repairs, hauling and supplies necessary for the drilling or recompletion of an oil or gas well and the preparation of such well for the production of oil or gas, but without any salvage value, which expenditures are generally accepted in the oil and gas industry as being currently deductible for federal income tax purposes. Examples of such costs include:

- ground clearing, drainage construction, location work, road making, temporary roads and ponds, surveying and geological works;
- drilling, completion, logging, cementing, acidizing, perforating and fracturing of wells;
- hauling mud and water, perforating, swabbing, supervision and overhead;
- renting horizontal tools, milling tools and bits; and
- construction of derricks, pipelines and other physical structures necessary for the drilling or preparation of the wells.

Lease. An instrument which grants to another (the lessee) the exclusive right to enter to explore for, drill for, produce, store and remove oil and natural gas on the mineral interest, in consideration for which the lessor is entitled to certain rents and royalties payable under the terms of the lease. Typically, the duration of the lessee's authorization is for a stated term of years and "for so long thereafter" as minerals are producing.

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

Mcf. One thousand cubic feet of natural gas at standard atmospheric conditions.

Mcfe. One thousand cubic feet equivalent of natural gas, calculated by converting oil to equivalent Mcf at a ratio of 6 Mcf to 1 Bbl of oil.

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

Mmcf. One million cubic feet of natural gas at standard atmospheric conditions.

Mmcfe. One million cubic feet equivalent of natural gas, calculated by converting oil to equivalent Mcf at a ratio of 6 Mcf to 1 Bbl of oil.

Net Acres. Gross acres multiplied by the percentage working interest owned by Warren.

PV-10 Value. The present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with SEC guidelines, net of estimated lease operating expense, production taxes and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization or Federal income taxes and discounted using an annual discount rate of 10%.

Net Wells. The sum of all the complete and partial well ownership interests (i.e., if we own 25% percent of the working interest in eight producing wells, the subtotal of this interest to the total net producing well count would be two net producing wells).

Net Production. Production that is owned by Warren less royalties and production due others.

NYMEX. New York Mercantile Exchange.

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

Permeability. The capacity of a geologic formation to allow water, natural gas or oil to pass through it.

Porosity. The ratio of the volume of all the pore spaces in a geologic formation to the volume of the whole formation.

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

Secondary Recovery. An artificial method or process used to restore or increase production from a reservoir after the primary production by the natural producing mechanism and reservoir pressure has experienced partial depletion. Gas injection and water flooding are examples of this technique.

Standardized Measure of Discounted Future Net Cash Flows. The present value of future discounted net cash flows attributed to proved oil and gas properties made by applying year end prices of oil and gas (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved oil and gas reserves, less estimated future expenditures (based on year end costs) to be incurred in developing and producing the proved reserves, less estimated future income tax expenses (based on year end statutory tax rates, with consideration of future tax rates already legislated) to be incurred on pretax net cash flows less tax basis of the properties and available credits, and assuming continuation of existing economic conditions. The estimated future net cash flows are then discounted using a rate of 10% per year to reflect the estimated timing of the future cash flows.

Tangible Drilling Costs. Expenditures necessary to develop oil or gas wells, including acquisition, transportation and storage costs, which typically are capitalized and depreciated for federal income tax purposes. Examples of such expenditures include:

- well casings;
- wellhead equipment;
- water disposal facilities;
- metering equipment;
- pumps;
- gathering lines; and
- storage tanks.

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

Waterflood. A secondary recovery operation in which water is injected into the producing formation in order to maintain reservoir pressure and force oil toward and into the producing wells.

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

Item 3: Legal Proceedings

Except as provided below, we are not engaged in any material legal proceedings to which we or our subsidiaries are a party or to which any of our property is subject.

On September 28, 1999, Magness Petroleum Company, our joint venture partner in the Wilmington Field, filed a complaint against Warren, Warren E & P, and certain Warren subsidiaries in the Superior Court of Los Angeles County, alleging that we had breached our joint venture agreement with Magness and an alleged oral agreement regarding advance payment of expenses for drilling and completion operations. Magness sought dissolution of the joint venture, an accounting and a declaratory judgment as to the rights of the parties under the joint venture agreement. We were successful in enforcing the arbitration provision in the joint venture agreement and entered into an agreement with Magness to submit the matter for arbitration by the Judicial Arbitration Mediation Services, or "JAMS," before the Honorable Keith J. Wisot, a retired Los Angeles Superior Court Judge. Judge Wisot, as the arbitrator, ruled that the joint venture agreement is a valid enforceable agreement, declined to dissolve the joint venture, denied Magness' claims for breach of contract, and held that he and JAMS would retain jurisdiction to enforce the award. On August 8, 2001, Magness filed a demand with the American Arbitration Association, or "AAA," reasserting its claims for dissolution of the joint venture and breach of contract. On August 20, 2001, Warren filed a request to resume arbitration before Judge Wisot and Magness filed an objection to such jurisdiction. On September 19, 2001, Warren petitioned the Superior Court of California for Los Angeles County to compel Magness to enter binding arbitration with Warren before Judge Wisot and JAMS. On October 5, 2001, Magness cross-petitioned to compel Warren to enter binding arbitration with Magness before AAA. On January 3, 2002, the Los Angeles Superior Court granted Warren's petition, denied Magness' petition and ordered Magness to discontinue its efforts to remove the controversy from the jurisdiction of JAMS and to proceed forthwith to arbitration before Judge Wisot of JAMS. Magness appealed this ruling by the Superior Court and on February 6, 2002, the Court of Appeal of the State of California stayed the January 3, 2002 order compelling arbitration before JAMS, pending a hearing on the lower court's ruling. The hearing was held before the Court of Appeal on September 27, 2002, and on November 18, 2002 the Court of Appeal rendered its opinion that the written agreement to arbitrate before JAMS (the "JAMS Agreement") entered into in December 1999 only covered matters and issues presented in and relating to the JAMS arbitration and that pursuant to the arbitration clause of the Joint Venture Agreement new issues or disputes not covered by the JAMS Agreement should be brought before the AAA. In response to a Motion for Rehearing filed by Warren, the Court of Appeal ordered on December 17, 2002 that its original opinion be modified to clarify that there has not been a determination whether Magness has complied in full with the JAMS arbitrator's Final Award. Warren believes that Magness has not fully complied and is in default of the JAMS Final Award is seeking enforcement of the Final Award, along with damages incurred by reason of Magness' failure to comply. In order to clarify what specific matters continue under JAMS jurisdiction pursuant to the original written stipulation for arbitration, on January 12, 2003, Warren filed a Motion for Clarification in the Superior Court of California along with a Motion for Enforcement of Final Award with JAMS.

A initial hearing of the Motion for Clarification was held before Judge Buckner of the Superior Court on February 20, 2003. At an interim hearing before Judge Buckner, he instructed the parties to present their proposed Orders and supporting briefs before April 4, 2003. Accordingly, pending final resolution, further development of the Wilmington Field will be curtailed.

In 1998, Warren E & P was sued in the 81st Judicial District Court of Frio County, Texas by Stricker Drilling Company, Inc. and Manning Safety Systems to recover the value of lost equipment based on a well blow out. Warren was later joined in the suit as a defendant. As a result of the lawsuit, Gotham Insurance Company, Warren E & P's well blow-out insurer, intervened. The suit was settled in 1999 with all parties except Gotham. Gotham paid over $1.7 million under the insurance policy and now seeks a refund of approximately $1.5 million of monies paid, denying coverage, and alleging fraud and misrepresentation and a failure of Warren E & P to act with due diligence and pursuant to safety regulations. Warren E & P countersued for the remaining proceeds under the policy coverage. In the summer and fall of 2000, summary judgments were entered for Warren E & P on essentially all claims except its bad faith claims against Gotham. Gotham's claims against Warren E & P and Warren were rejected. Final judgment was rendered on May 14, 2001 in Warren E & P's favor for the remaining policy proceeds, interest and attorney fees. Gotham has appealed the final judgment. Warren E & P is defending the judgment on appeal although seeking to reverse the ruling denying its bad faith claim. The case on appeal was orally argued on March 28, 2002. We are awaiting the appeals court decision.

We are also a party to legal actions arising in the ordinary course of our business. In the opinion of our management, based in part on consultation with legal counsel, the liability, if any, under these claims is either adequately covered by insurance or would not have a material adverse effect on us.

Item 4: Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of security holders during the fourth quarter of the fiscal year 2002.

PART II

Item 5: Market for the Registrant's Common Equity and Related Stockholder Matters

No Public Market—Shares Eligible For Future Sale

There is no public market for our common stock. Future sales of substantial amounts of common stock in any public trading market which develops could adversely affect the market price of our common stock. As of March 27, 2003, 17,581,996 shares of common stock were issued and outstanding. Pursuant to Rule 144 under the Securities Act, commencing March 26, 2002, which was 90 days following the effectiveness of our Form 10 registration statement, approximately 9,666,547 shares of our common stock became freely tradeable in accordance with Rule 144(k) and approximately 7,871,032 shares, including 6,045,949 shares owned by affiliates, may be sold in accordance with the volume limitation imposed by Rule 144.

As of March 15, 2003, 1,514,459 shares of our common stock are issuable upon the exercise of options granted or to be granted under our various stock option plans. See "Item 11—"Executive Compensation—Employee Benefit Plans" and note D to our consolidated financial statements. As of that same date, 5,768,903 shares of common stock were issuable upon the conversion of our convertible debt.

Registration Rights

As of December 31, 2002, holders of approximately 3,493,571 shares of our common stock issued pursuant to the exercise of our Class A, B, C and D warrants and 5,768,903 shares of our common stock issuable upon conversion of existing convertible debt are eligible to sell such shares under

Rule 144. A substantial number of such shares may have rights, subject to some conditions including the consent of any underwriter, to include their shares in registration statements that we may file, if any, to register shares of our common stock under the Securities Act for ourselves or other shareholders. Commencing January 1, 2004, under the registration rights agreement dated December 12, 2002, holders of approximately 3,212,317 shares of our convertible preferred shares as of March 19, 2003, which will be issued on or around March 31, 2003 as part of the next closing, have one right to demand that the up to 3,212,317 shares of common stock issuable upon conversion of the convertible preferred shares be registered under the Securities Act of 1933, as amended. Additionally, the holders may have right to include those 3,212,317 shares of common stock, subject to the consent of any underwriter, to include their shares in registration statements that we may file, if any, to register shares of our common stock under the Securities Act for ourselves or other shareholders.

Holders

As of March 27, 2003, there were approximately 3,710 holders of our common stock.

Dividend Policy

We have never paid or declared any cash dividends on our common stock. We currently intend to retain earnings, if any, to finance the growth and development of our business and we do not expect to pay any cash dividends on our common stock in the foreseeable future. Payment of future cash dividends, if any, will be at the discretion of our board of directors after taking into account various factors, including our financial condition, operating results, current and anticipated cash needs and plans for expansion.

Item 6: Selected Consolidated Financial Data

The following tables present selected financial and operating data for Warren and its subsidiaries as of and for the periods indicated. You should read the following selected data along with "Item 7-Management's Discussion and Analysis of Financial Condition and Results of Operations," our financial statements and the related notes and other information included in this registration statement. The selected financial data as of December 31, 1998, 1999, 2000, 2001 and 2002 has been derived from our financial statements, which were audited by Grant Thornton LLP, independent auditors, and were prepared in accordance with accounting principles generally accepted in the United States of America. The historical results presented below are not necessarily indicative of the results to be expected for any future period.

(Dollars in thousands except for share information)

	Year ended December 31,				
	1998	1999	2000	2001	2002
Consolidated Statement of Operations Data:					
Revenues:					
Turnkey contracts	$ 24,161	$ 25,406	$ 33,985	$ 30,103	$ 5,841
Oil & gas sales from marketing activities	—	—	15,421	14,867	11,272
Well Services	—	2,611	4,297	5,574	1,895
Oil & gas sales	63	68	200	948	593
Total operating revenues	24,224	28,085	53,903	51,492	19,601
Costs and operating expenses:					
Turnkey contracts	20,340	18,126	22,783	25,953	4,965
Cost of oil and gas marketing activities	—	—	15,800	15,299	11,121
Well services	—	1,351	3,168	3,519	839
Production and exploration	37	43	355	568	1,326
Depreciation, depletion and Amortization	8,149	9,197	3,065	14,462	9,930
Remarketing Obligation	—	—	—	3,319	(3,065)
General and administrative	3,931	4,491	6,416	5,485	6,278
Total operating expenses	32,457	33,208	51,587	68,605	31,394
Income (loss) from operations	(8,233)	(5,123)	2,316	(17,113)	(11,793)
Other income (expense):					
Interest and other income	2,439	1,641	2,457	1,977	5,258
Interest expense	(4,673)	(5,791)	(6,968)	(5,776)	(6,313)
Gain on sale of assets	—	—	—	—	4,287
Net gain (loss) on investment	5,489	(1,104)	587	(10)	464
Income (loss) before income taxes and extraordinary item	(4,978)	(10,377)	(1,608)	(20,922)	(8,097)
Income tax expense (credit)	591	702	(412)	152	(471)
Net Loss	(5,569)	(11,079)	(1,196)	(21,074)	(7,626)
Provision for Preferred Dividends	—	—	—	—	16
Net income (loss)	$ (5,569)	$ (11,079)	$ (1,196)	$ (21,074)	(7,642)
Weighted average number of common shares Outstanding:					
Basic and diluted	9,106,998	11,115,522	12,461,814	17,532,882	17,339,869
Net income (loss) per common share:					
Basic and diluted	$ (0.61)	$ (1.00)	$ (0.10)	$ (1.20)	$ (0.44)
Consolidated Statement of Cash Flows Data:					
Net cash provided by (used in):					
Operating Activities	$ (155)	$ 16,502	$ 10,659	$ (15,712)	$ (6,101)
Investing Activities	5,626	(21,540)	(19,012)	(17,635)	5,317
Financing Activities	12,611	16,726	26,701	(2,700)	1,045

	As of December 31,				
	1998	1999	2000	2001	2002
Balance Sheet Data:					
Cash and cash Equivalents	$ 28,934	$ 40,622	$ 58,970	$22,924	$ 23,184
Total assets	60,458	82,144	128,649	94,900	108,262
Total long-term debt	38,311	56,306	60,447	58,561	56,202
Shareholders' equity (deficit)	(3,784)	(14,618)	14,876	(6,434)	7,002

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

You should read the following discussion and analysis together with our financial statements and accompanying notes appearing elsewhere in this registration statement. The following information contains forward-looking statements. See "Forward-Looking Statements." Actual results may differ materially from those anticipated due to many factors, including those set forth under "Risk Factors" below.

Critical Accounting Policies

Oil and Gas Producing Activities

We use the successful efforts method of accounting for our investments in natural gas and oil properties. Under this method, we capitalize lease acquisition costs and intangible drilling and development costs on successful exploratory wells and all development wells. Wells are depleted on a field by field basis and are evaluated on a field by field basis for impairment. We have substantially subordinated to investors all of our joint venture and general partner's rights to production for wells syndicated to our drilling programs formed during or prior to 1998.

We review our natural gas and oil properties on a field level for impairment when circumstances indicate that the capitalized costs less accumulated depreciation, depletion and amortization or the "carrying value," of the property may not be recoverable. If the carrying value of the property exceeds the expected future undiscounted cash flows, an amount equal to the excess of the carrying value over the fair value of the property (generally based upon discounted cash flow) is charged to expense. An impairment results in a non-cash charge to earnings but does not affect cash flows.

Our oil and gas producing activities are dependent upon the price of natural gas and oil. Declines in the price of natural gas and oil may result in write downs of our oil and gas properties and a related impairment expense. Additionally, price declines of natural gas and oil could result in our wells becoming uneconomical to operate. As a result, we may be required to expend funds for plugging and abandoning wells which are deemed to be uneconomical. Lastly, price declines may result in delays developing our proved undeveloped reserves. A significant portion of our proved reserves has not been developed. As a result, price declines may render drilling projects uneconomical to develop.

Turnkey Contract Activities

We provide turnkey contract drilling services to affiliated drilling programs whereby the investors pay intangible development costs and we pay lease acquisition and completion costs, including lease and well equipment. We record revenue from turnkey drilling contracts on the percentage of completion method based on total costs incurred to total estimated costs to complete. We contract to drill wells on behalf of drilling programs for a fixed price given the location, depth, formation characteristics and type of drilling (vertical, directional or horizontal). We subsequently enter into third party contracts to drill the well at current market rates. Since the drilling contract is on a day work or "per day" basis, the longer the drilling rig is on the well, the higher our costs are in the well. If problems are encountered during drilling which require more effort from our third party subcontractors our gross profits will be reduced on the well. If substantial problems occur such as the loss of the hole, lost equipment downhole or a blow out, we may incur a loss on the well. Our estimates of cost to complete wells drive our revenue recognition under percentage of completion. We may recognize profits on wells in progress in a period, but if we underestimate the cost to complete the wells we may recognize losses on the wells in a subsequent period.

At December 31, 2002, we had estimated remaining cash contractual drilling commitments under the turnkey drilling contracts with the drilling programs formed in 1999, 2000 and 2001 of $2.9 million, $15.1 million and $10.2 million, respectively, for some wells that were timely commenced in early 2000 through 2002, but were not yet completed due to a number of unforeseen factors even though we are continuing to proceed with reasonable diligence. Under the turnkey drilling contracts, we had received full cash payment from the drilling programs in 1999 through 2001 for all of the wells to be drilled on behalf of the 1999 through 2001 drilling programs.

During 2002, we raised $5.4 million in new drilling programs. This amount compares to $18.1 million and $46.5 million raised for our drilling programs during 2001 and 2000, respectively. We believe there were a number of factors affecting us in 2002 that caused us to raise fewer drilling funds in 2002. Foremost, our 2001 and prior drilling programs performed poorly in 2002 compared to prior years, largely as a result of the decrease in cash distributions to drilling program investors because of declining production and decreases in energy prices during 2002. Additionally, regulatory delays related to various permits to complete the development of our coalbed methane (CBM) reserves in the Washakie Basin and the pending litigation relating to our interest in the Wilmington Field in California reduced potential cash distributions.

We were paid the total turnkey drilling contract price for the 1999 programs in 1999, the 2000 programs in 2000 and the 2001 programs in 2001, commenced drilling within 90 days after the end of the applicable preceding tax year for each of respective programs, and have proceeded with reasonable diligence since that date to drill and complete the wells. Since 2000 and 2001, we have expended as the turnkey contractor for the benefit of the 1999 programs an amount greater than the total turnkey contract price less the permitted profit margin earned by us for such programs, although we have more wells to complete. Further, at March 27, 2003, although we have remaining obligations for the prior programs, we believe that we are in compliance with the turnkey contract.

Repurchase Agreements

Under certain repurchase agreements, the investors in certain drilling programs have a right to have their interests purchased by a repurchase agent or us. We unconditionally guarantee the repurchase agent's performance. The purchase price is calculated at a formula price and is payable from seven to 25 years from the date of admission to the drilling program. We determine the amount of the repurchase liability by computing the present value of the excess of the formula price over the estimated discounted present value of future net revenues of proved developed and undeveloped reserves of each drilling program net of future capital costs and our working interests. A portion of some drilling program properties are proved undeveloped leases which must be drilled by us using funds from an outside party or from us to provide cash flow to the drilling programs which satisfy the repurchase obligation. We have estimated that those undeveloped leases will require approximately $26.1 million of development expenditures in 2003, 2004 and 2005 to complete these wells.

The determination of whether a repurchase liability exists is based upon estimates of future net cash flows from reserve studies prepared by petroleum engineers. These reserve studies are inherently imprecise and will change as future information becomes available. Decreases in prices received for oil and gas produced by drilling programs results in smaller cash distributions to investors and payout may not occur before the future date at which the investors have a right to require repurchase of their interests. Under the formula for repurchase in 1997 and earlier drilling programs, low oil and gas prices at the future date may result in us being required to repurchase investor interests at prices greater than fair value. An expense recognition would therefore be necessary.

If oil and gas prices decrease, we may determine that proved undeveloped leases in drilling programs are not economical to drill and develop. As a result, cash flow from these leases will not be distributed to investors and payout may be delayed. If payout has not occurred in these drilling programs before the date investors can require repurchase of their interests, we may be required to purchase interests containing proved undeveloped leases based on a petroleum engineer's estimate of the present value of net cash flow. The price paid may be in excess of the fair value of the interest resulting in a charge to expense. At December 31, 2001 and 2002, the face amounts of U.S. treasury bonds securing such repurchase agreements were $4.6 million and $4.4 million, respectively, and the market value was $1.6 million and $1.8 million, respectively.

In late 2002, each of the thirteen drilling programs formed from 1994 through 1997 commenced a Vote Solicitation of their partners to: (i) obtain the requisite 2/3rds affirmative vote of their respective partners to convert their drilling program from a Delaware limited partnership to an LLC wherein all LLC members would have limited liability, including Warren, and (ii) allow partners to select whether they wanted to be (a) a standard member in the LLC with substantially the same rights and obligations that they had as partners in their respective drilling fund, or (b) a Preferred Member in the LLC having certain preferential rights by consenting to Warren's contribution of additional capital to the LLC upon conversion (the "Recapitalization") in the form of its unregistered Preferred Shares in an amount equal to between 110% to 120% of the potential repurchase price of consenting partner's interests calculated as of December 31, 2002. For its additional capital contribution, Warren received additional standard membership interests in the LLC and was specially allocated a prorata interest as a standard member in the wells and oil leases formerly allocable to the partners who elected to become Preferred Members. Election by a partner to become a Preferred Member terminated their repurchase rights under the original buy/sell agreements. At December 31, 2002, six of the thirteen programs obtained the requisite votes to convert to LLCs and on average 71.3% of the program members elected to become Preferred Members in their LLC. As a result under the Recapitalization, Warren issued 1,342,960 Preferred Shares in the aggregate to the six LLCs as an additional capital contribution and received its prorata share of additional standard membership interests in the LLCs.

Additionally, as of March 19, 2003, all thirteen drilling programs have received the necessary 2/3rds affirmative votes necessary to convert to LLCs and on average 72.1% of the program members elected to become Preferred Members. As a result, as of March 19, 2003, Warren will issue in the aggregate 3,212,317 shares of Preferred Stock on or around March 31, 2003, as additional capital to the thirteen LLCs and received its prorata share of additional standard membership interests in the LLCs.

Liquidity and Capital Resources

We have funded our activities primarily with the proceeds raised through privately placed drilling programs and our private sale of our equity and debt securities. These private placements primarily were made through a network of independent broker dealers. Since 1992, we have raised approximately $222 million through the private placements of interests in 30 drilling programs. Additionally, we have raised $58.7 million through the issuance of our debt securities and $56.5 million through the issuance of our equity securities. In our drilling programs, we fund the costs associated with acreage acquisition and the tangible portion of drilling activities, while investors in the drilling programs fund all intangible drilling costs.

During 2002, we raised $5.4 million through the private placements of interests in our drilling programs. Cumulatively, we raised $70.1 million during fiscal years 2002, 2001 and 2000 through the private placements of interests in our drilling programs. During 2002, we raised $4.3 through the private placements of our Preferred Stock. Cumulatively, we raised $33.4 million during fiscal years 2002, 2001 and 2000 through the private placements of our debt or equity securities and the cash exercise of our warrants for common shares.

Our most material commitment of funds relates to our drilling programs. Our deferred revenue balance relating to our drilling commitments totaled $32.3 million at December 31, 2002. This commitment varies pro rata with the amount of funds raised through our drilling funds.

We are obligated to make equal annual deposits to a bond sinking fund for certain debentures. These deposits include U.S. treasury bonds with maturity dates prior to the maturity date of the related debenture. The estimated annual sinking fund requirements disclosed below are calculated using U.S. treasury bond pricing as of December 31, 2002. The holders of debentures may annually ask us to redeem up to 10% of the original amount we issued. The following tables present our contractual obligations due by period and other commitments by period.

The contractual obligations table below assumes the maximum amount is tendered each year, net of the effects of the sinking fund requirements. The table does not give effect to the conversion of any bonds to stock which would reduce payments due.

Contractual Obligations As of December 31, 2002	Payments due by period Total	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
Debentures—net of Sinking Fund Requirements	$23,153,670	$1,835,219	$ 3,193,503	$ 2,560,864	$15,564,084
Debenture Sinking Fund Requirements	31,516,029	3,631,751	7,740,437	8,373,075	11,770,766
Leases	734,812	189,911	311,372	233,529	—
Total	$55,404,511	$5,656,881	$11,245,312	$11,167,468	$27,334,850

For partnerships formed before 1998, the repurchase price is computed as the original capital contribution of the investor reduced by the greater of (1) cash distributions we made to the investor, or (2) 10% for every $1.00 which the oil price at the repurchase date is below $13.00 per barrel adjusted by the consumer price index changes since the programs formation. For programs formed 1998 and later, the repurchase price cannot exceed the present value of the respective program's proved reserves. If we purchase interests in drilling programs, we receive the pro rata share of the reserves and related future net cash flows. The table below presents the repurchase commitment associated with 20 drilling programs, giving no effect to any reserve value that is acquired in repurchase.

Other Commitments As of December 31, 2002	Amount of repurchase commitment per period Total	Less Than 1 Year	1-3 Years	4-5 Years	After 5 Years
Partnership repurchase commitments					
Pre-1998 partnerships without present value limit	$ 31,636,261	$ 3,524,662	$25,837,851	$ —	$ 2,273,748
1998 and later partnerships with present value limit	100,442,022	—	—	45,850,357	54,591,665
Total	$132,078,283	$ 3,524,662	$25,837,851	$45,850,357	$56,865,413

As a result of the Recapitalizations mentioned above, the amount of repurchase commitments has significantly decreased as of February 28, 2003 as follows:

Other Commitments As of February 28, 2003	Amount of repurchase commitment per period Total	Less Than 1 Year	1-3 Years	4-5 Years	After 5 Years
Partnership repurchase commitments					
Pre-1998 partnerships without present Value limit	$13,031,963	$1,543,047	$9,764,396	$ —	$ 1,724,520
1998 and later partnerships with present value limit	100,262,290	—	—	45,713,966	54,548,324
Total	$13,294,253	$1,543,047	$9,764,396	$45,713,966	$56,272,844

During the year ended December 31, 2002, our liquidity improved from a working capital deficit of $8.9 million at December 31, 2001 to a working capital deficit of $7.8 million at December 31, 2002. Primarily, this small improvement resulted from the previously mentioned Exchange Agreement and the Joint Exploration Agreement with Anadarko Petroleum Corporation consummated on December 13, 2002. Under the terms of the agreements, Anadarko paid to Warren $12.0 million in cash, $6.0 million in drilling credits payable over three years, conveyed a 50% interest in lands within the area of mutual interest (AMI) consisting of approximately 49,846 net acres and reimbursed Warren approximately $4.3 million for costs incurred by Warren with respect to the development of this project. Pursuant to these agreements, Warren conveyed a 50% interest in lands within the AMI consisting of approximately 86,394 net acres.

Management Plans for 2003

The Company has incurred a net loss of approximately $7.6 million during 2002. At December 31, 2002, current liabilities exceeded current assets by approximately $7.8 million. We had a net book value of $7.0 million.

The 2002 net loss includes approximately $13.6 million of noncash charges including oil and gas properties impairments and a reversal of previously recognized deferred revenue relating to wells conveyed to Anadarko in the Exchange Agreement and Joint Exploration Agreement entered into on December 13, 2002. Wells that had been previously allocated to drilling programs were conveyed to Anadarko. As a result, turnkey revenue which had been recognized on those wells was reversed.

In order to improve operations and liquidity and meet our cash flow needs, we have or intend to do the following:

- Raise additional capital through the sale of preferred stock.
- Obtain a credit facility based in part on the value of our proven reserves.
- Continue privately placed drilling programs, which based on prior experience management anticipates raising approximately $10 million in 2003.
- Generate turnkey profit and operating cash flow from turnkey drilling contracts equal to approximately 25% of the total amount of total turnkey price.
- Reduce fixed overhead expenses and primarily conduct developmental drilling operations in the Company's two main target areas, coalbed methane properties in Wyoming and oil formations in the Wilmington field in California.

As a result of these plans, management believes that it will generate sufficient cash flows to meet its current obligations in 2003.

Results of Operations

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

Turnkey contract revenue and expenses. Turnkey contract revenue decreased $24.3 million in 2002 to $5.8 million, an 81% decrease compared to levels during 2001. The decrease in turnkey revenue resulted from significantly less drilling and completion activity on behalf of the drilling programs during 2002 compared to 2001. The level of drilling activity is affected by the amount of funds raised from our drilling programs in the prior fiscal year. We raised $18.1 million from our drilling programs during 2001 compared to $46.5 million during 2000. During 2002 and 2001, we drilled zero and five East Texas James Lime wells, respectively. These wells were multi-lateral, horizontal wells that cost several million dollars to drill and complete in the aggregate. Additionally, we contributed a 50% working interest in 24 previously drilled or partially drilled wells in the AMI to Anadarko as part of the Joint Venture. These wells had been previously allocated to drilling programs. As a result, we reversed previously recognized turnkey revenue during the 4th quarter of 2002.

Turnkey contract expense decreased $21.0 million during 2002 to $5.0 million, an 81% decrease compared to 2001. This decrease resulted from the decrease in drilling and completion activities on behalf of the drilling programs during 2002 compared to 2001, as mentioned above. Additionally, certain intangible drilling costs incurred from August 1, 2002 through December 12, 2002 were reimbursed by Anadarko at the closing of the Joint Venture on December 13, 2002. Lastly, a portion of the proceeds received by Anadarko from the Joint Venture was allocated to previously drilled wells in the AMI, thereby reducing turnkey expense and reducing the gain recognized on the transaction.

Gross profit from turnkey contract revenue and expenses was $876 thousand or 15% in 2002. This compared to gross profit of $4.1 million or 14% in 2001. The fluctuation in gross profit percentage is not considered material.

Natural gas and oil sales and costs from marketing activities. Natural gas and oil sales from marketing activities decreased $3.6 million in 2002 to $11.3 million, a 24% decrease compared to 2001. Cost of oil and gas marketing activities decreased $4.2 million in 2002 to $11.1 million, a 27% decrease compared to 2001. These decreases resulted from a decrease in the average prices of natural gas and oil during 2002 compared to 2001. The average price of natural gas and oil marketed and sold during 2002 was $1.90 per Mcf and $20.84 per barrel, respectively, or $2.40 per Mcfe. This compared to the average price of natural gas and oil marketed and sold during 2001 of $2.83 and $16.74, respectively, or $2.82 per Mcfe. Additionally, natural gas and oil related to our drilling programs being purchased by us at the wellhead and subsequently marketed and sold decreased. Natural gas and oil production allocated to drilling programs totaled 3.5 Bcfe in 2002 compared to 5.1 Bcfe in 2001.

The gross profit (loss) from marketing activities for 2002 was a $151 thousand profit compared to a $432 thousand loss in 2001. The 2001 loss resulted from a hedging transaction, which expired on March 31, 2001. The total hedging loss incurred by Warren was $0.5 million from January 2001 to March 2001.

Well services activities. Well services revenue decreased $3.7 million in 2002 to $1.9 million, a 66% decrease compared to 2001. Well services expense decreased $2.7 million in 2002 to $839 thousand, a 76% decrease compared to 2001. These decreases in resulted from the sale of our drilling rig subsidiary in February 2002. Well services revenue and expense from our drilling rig subsidiary declined $3.6 million and $2.7 million, respectively, during 2002.

Gross profit from well services activities was $1.1 million or 56% in 2002. This compared to gross profit of $2.1 million or 37% in 2001. This increase in gross profit percentage during 2002 resulted from the increase in gross profit percentage related to drilling supervision and administrative overhead. Drilling supervision and administrative overhead revenue totaled $1.5 million in 2002 compared to the related expense of $600 thousand, resulting in a gross profit percentage of 60%. Drilling supervision and administrative overhead revenue totaled $1.6 million in 2001 compared to the related expense of $900 thousand, resulting in a gross profit percentage of 45%.

Natural gas and oil sales and production and exploration expenses. Natural gas and oil sales decreased $356 thousand in 2002 to $593 thousand, a 38% decrease compared to 2001. The decrease resulted from a settlement payment of $400 thousand received by us in 2001 from an unaffiliated entity relating to previously held suspense funds. Production and exploration expense increased $758 thousand in 2002 to $1.3 million, a 134% increase compared to 2001. Primarily, the increase resulted from $310 thousand of plugging and abandonment expense and $190 thousand of 3-D seismic expense recorded in 2002.

Net gain (loss) on investments. Net gain on investments was $464 thousand for 2002. Net loss on investments was $10 thousand for 2001. Originally, Warren obtained U.S. treasury bonds, which typically represented less than 1% of Warren's total current assets, to assure the financial capability to repurchase partnership units under the partnership agreements and fund the repayment of outstanding debentures. This obligation was eliminated for the majority of partnership units and debenture holders in 1998. As a result, these escrowed U.S. treasury bonds were released for Warren's unrestricted use and liquidated shortly thereafter.

Primarily, investments represent zero coupon U.S. treasury bonds held in our inventory. Fluctuations in net gain or loss on investments resulted from changes in long term interest rates.

Gain on sale of assets. The gain on the sale of assets of $4.3 million resulted from the Joint Venture with Anadarko. Under the Joint Venture, we contributed 86,394 net acres and Anadarko contributed 49,846 net acres to the joint venture. Additionally, Anadarko paid to us $12 million in cash and $6 million in future drilling credits. As a result, we recognized a $4.3 million gain on sale of assets.

Interest and other income. Interest and other income increased $3.3 million in 2002 to $5.3 million, a 166% increase compared to 2001. Primarily, this increase resulted from a key man life insurance payment received by us relating to the death of our Executive Vice President, James C. Johnson, Jr. in December 2002. The insurance proceeds totaled $3.8 million. This increase was partially offset by lower interest income earned during 2002 resulting from lower interest rates.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense decreased $4.5 million in 2002 to $9.9 million, a 31% decrease compared to 2001. This decrease resulted from depletion and impairment expense of $9.3 million during 2002 compared to $10.3 during 2001. Additionally, during 2002, depletion expense on oil and gas properties decreased $1.4 million due to the lower oil and gas property balances during 2002 compared to 2001. Also, in 2001, we recorded a $0.6 million of impairment expense related to the fixed assets of Pinnacle. Lastly, during 2001, depreciation and depletion related to the Warren E & P acquisition was $0.3 million. We acquired Warren E & P on September 1, 2000.

General and administrative expenses. General and administrative expenses increased $0.8 million in 2002 to $6.3 million, a 14% increase compared to 2001. Primarily, this increase resulted from allocating a higher percentage of payroll and office expenses to general and administrative expense and a lower percentage of these expenses to turnkey expense.

Interest expense. Interest expense increased $0.5 million in 2002 to $6.3 million, a 9% increase compared to 2001. Primarily, the increase is attributable to an decrease in capitalized interest during 2002 compared to 2001. We recorded $1.4 million of capitalized interest during 2002 compared to $2.3 million during 2001. Primarily, capitalized interest relates to our development project in the Washakie Basin.

Remarketing Obligation. Remarketing obligation expense of $3.3 million was recorded in 2001 based on pricing at March 15, 2002. The remarking obligation expense was reversed during the 1st quarter of 2002. As stated above, the determination of whether a repurchase liability exists is based upon estimates of future net cash flows from reserve studies prepared by petroleum engineers compared to the potential repurchase of drilling program units. Significant decreases in natural gas and oil prices at December 31, 2001 lowered the estimated future cash flows when compared to future potential repurchase obligations. As a result, a remarketing liability and a remarketing obligation expense of $3.3 million was recorded in 2001.

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Turnkey contract revenue and expenses. Turnkey contract revenue decreased $3.9 million in 2001 to $30.1 million, an 11% decrease compared to levels during 2000. The decrease in turnkey revenue resulted from an increase in the estimated costs totaling $6.8 million to complete our drilling obligation relating to the 2000 and 1999 drilling programs. Additionally, turnkey contract expense increased $3.2 million during 2001 to $26 million, a 14% increase compared to 2000. This increase resulted from an increase in drilling and completion activities on behalf of the drilling programs during 2001 compared to 2000. The level of drilling activity is affected by the amount of funds raised from our drilling programs in the prior fiscal year. We raised $46.5 million from our drilling programs during 2000 compared to $40.9 million during 1999.

Gross profit from turnkey contract revenue and expenses was $4.1 million or 14% in 2001. This compared to gross profit of $11.2 million or 33% in 2000. The decrease in gross profit percentage during 2001 resulted from an increase in the estimated costs totaling $6.8 million to complete our drilling obligation relating to the 2000 and 1999 drilling programs.

Natural gas and oil sales and costs from marketing activities. Natural gas and oil sales from marketing activities decreased $0.6 million in 2001 to $14.9 million, a 4% decrease compared to 2000. Cost of oil and gas marketing activities decreased $0.5 million in 2001 to $15.3 million, a 3% decrease compared to 2000. These decreases resulted from a decrease in the average prices of natural gas and oil during 2001 compared to 2000. The average price of natural gas and oil marketed and sold during 2001 was $2.29 and $15.49, respectively. This compared to the average price of natural gas and oil marketed and sold during 2000 of $2.57 and $23.70, respectively. This decrease was offset by an increase in natural gas and oil related to our drilling programs being purchased by us at the wellhead and subsequently marketed and sold. Natural gas and oil production allocated to drilling programs totaled 5.1 Bcfe in 2001 compared to 4.1 Bcfe in 2000.

The gross profit (loss) from marketing activities for 2001 was a $0.4 million loss as well as for 2000. Both losses resulted from a hedging transaction, which expired on March 31, 2001. The total hedging loss incurred by Warren was $0.5 million from January 2001 to March 2001 compared to a hedging loss of $1.6 million for 2000.

Well services activities. Well services revenue increased $1.3 million in 2001 to $5.6 million, a 30% increase compared to 2000. Well services expense increased $0.4 million in 2001 to $3.5 million, an 11% increase compared to 2000. The increase in well services revenue results from drilling supervision revenue of $0.9 million during 2001 compared to $0.3 million during 2000. Additionally, the increases in revenue and expenses resulted from increases in drilling rig day rates and increased rig utilization during 2001 compared to 2000.

Gross profit from well services activities was $2.1 million or 37% in 2001. This compared to gross profit of $1.1 million or 26% in 2000. This increase in gross profit percentage during 2001 resulted from drilling and supervision fees of $0.9 million during 2001 compared to $0.3 during 2000. Also, increases in productivity resulted from increases in drilling rig day rates and increased rig utilization during 2001 compared to 2000. Additionally, $1.0 million of well services depreciation expense is included in depreciation, depletion and amortization for 2001 and 2000.

Natural gas and oil sales and production and exploration expenses. We have interests in natural gas and oil production attributable to our drilling programs. Through and prior to June 30, 2001, virtually all of our production was subordinated to our investors in the drilling programs. Beginning in the third quarter of 2001, we received an additional $0.3 million in natural gas and oil revenue from our interests in production from certain wells in drilling programs formed during 1999 and 2000. Our share of pre-payout production from these programs is generally 25% of the production allocated to these drilling programs.

Interest and other income. Interest income decreased $0.5 million in 2001 to $2.0 million, a 20% decrease compared to 2000. Primarily, the decrease is attributable to lower interest rates during 2001 than in 2000.

Net gain (loss) on investments. Net loss on investments was $10 thousand for 2001. Net gain on investments was $0.6 million for 2000. Originally, Warren obtained U.S. treasury bonds, which typically represented less than 1% of Warren's total current assets, to assure the financial capability to repurchase partnership units under the partnership agreements and fund the repayment of outstanding debentures. This obligation was eliminated for the majority of partnership units and debenture holders in 1998. As a result, these escrowed U.S. treasury bonds were released for Warren's unrestricted use and liquidated shortly thereafter.

Primarily, investments represent zero coupon U.S. treasury bonds held in our inventory. Fluctuations in net gain or loss on investments resulted from changes in long term interest rates.

General and administrative expenses. General and administrative expenses decreased $0.9 million in 2001 to $5.5 million, a 15% decrease compared to 2000. Primarily, this decrease resulted from a decrease in certain pre and post production expenses paid by us for the benefit of the drilling programs. Predominantly, these pre-production expenses represent lease operating expenses incurred prior to the commencement of production. Post production expenses represent repairs to equipment during the first 12 months of production.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased $11.4 million in 2001 to $14.5 million, a 372% increase compared to 2000. This increase resulted from depletion and impairment expense of $12.8 million during 2001 compared to $2.3 during 2000. The significant increase in depletion and impairment expense resulted from a significant decrease in energy prices at December 31, 2001 compared to December 31, 2000. Additionally, we recorded a $0.6 million of impairment expense related to the fixed assets of Pinnacle. Lastly, depreciation and depletion related to the Warren E & P acquisition increased $0.3 million during 2001 compared to 2000. We acquired Warren E & P on September 1, 2000.

Interest expense. Interest expense decreased $1.2 million in 2001 to $5.8 million, a 17% decrease compared to 2000. Primarily, the decrease is attributable to an increase in capitalized interest during 2001 compared to 2000. We recorded $2.3 million of capitalized interest during 2001 compared to $1.3 million during 2000. Primarily, capitalized interest relates to our development project in the Washakie Basin.

Warren financed the acquisition of $6.9 million and $11.6 million of oil and gas properties during 2001 and 2000, respectively. Warren had approximately $54 million in debentures outstanding at December 31, 1999. During 2000, Warren issued approximately $15 million of additional debentures and converted approximately $10 million of debentures into common shares, resulting in an outstanding debenture balance of approximately $59 million at December 31, 2000. During 2001, Warren redeemed approximately $0.9 million in debentures resulting in an outstanding balance of $58.1 million at December 31, 2001.

Remarketing Obligation. Remarketing obligation expense of $3.3 million was recorded in 2001 based on pricing at March 15, 2002. No remarketing expense was recorded in 2000. As stated above, the determination of whether a repurchase liability exists is based upon estimates of future net cash flows from reserve studies prepared by petroleum engineers compared to the potential repurchase of drilling program units. Significant decreases in natural gas and oil prices at December 31, 2001 lowered the estimated future cash flows when compared to future potential repurchase obligations. As a result, a remarketing liability and a remarketing obligation expense of $3.3 million was recorded in 2001.

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

Turnkey contract activities. Turnkey contract revenue increased $8.6 million in 2000 to $34.0 million, a 34% increase compared to such revenues in 1999. Additionally, turnkey contract expense increased $4.7 million in 2000 to $22.8 million, a 26% increase compared to the level of such costs in 1999. These increases resulted from an increase in drilling and completion activities on behalf of the drilling programs during 2000 compared to 1999. The level of drilling activity is affected by the amount of funds raised from our drilling programs in the prior periods. We raised $40.9 million from drilling programs during 1999, compared to $20.6 million raised during 1998.

Gross profit from turnkey contract revenue and expense was $11.1 million, or 33%. This compared to gross profit of $7.3 million, or 29%. The increase in percentage gross profit in 2000 resulted from turnkey revenue related to two drilling programs with no gross profit limitation. The gross profit we earned relating to these two drilling programs was $3.3 million, or 51.7%.

Natural gas and oil sales and costs from marketing activities. Natural gas and oil sales from marketing activities did not commence until January 1, 2000. There were no such sales during 1999. The gross profit from marketing activities for the year ended December 31, 2000, was a $0.4 million loss, due primarily to a hedging loss of $1.6 million.

Well services activities. Well services revenue increased by $1.7 million in 2000 to $4.3 million, a 65% increase compared to 1999. Well services expense increased $1.8 million in 2000 to $3.2 million, a 134% increase compared to 1999. This increase resulted from a significant change in the customer base. During 2000, our drilling subsidiary customer base was 95% unaffiliated third parties and 5% affiliated drilling programs. During 1999, the customer base was 51% unaffiliated third parties and 49% affiliated drilling programs. As a result, well services revenue and expense related to affiliated drilling programs was eliminated through consolidation entries.

Interest and other income. Interest income increased $0.8 million in 2000 to $2.5 million, a 50% increase compared to such income in 1999. Primarily, the increase is attributable to a higher average cash and cash equivalent balance during 2000 than in 1999.

Net gain (loss) on investments. Net gain on investments was $0.6 million for 2000. Net loss on investments was $1.1 million for 1999. Primarily, investments represent zero coupon U.S. treasury bonds held in our inventory. Primarily, fluctuations in net gain or loss on investments result from changes in interest rates.

General and Administrative. General and administrative expenses increased $1.9 million in 2000 to $6.4 million, a 43% increase compared to 1999. Primarily, this increase resulted from an increase in certain pre-production and post-production expenses paid by us for the benefit of our drilling programs. Such expenses were $3.6 million and $2.1 million in 2000 and 1999, respectively. Additionally, this increase resulted from increased commissions of $0.7 million paid to broker dealers selling a higher amount of drilling programs and debentures during 2000 as compared to amounts sold in 1999. Additionally, Warren E & P was acquired on September 1, 2000, with general and administrative expenses relating to Warren E & P totaling $0.2 million during 2000.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense decreased $6.1 million in 2000 to $3.1 million, a 67% decrease compared to 1999. Primarily, depreciation, depletion and amortization was lower in 2000 due to impairment expense totaling $7.8 million during 1999 compared to $1.9 million during 2000.

Interest expense. Interest expense increased $1.2 million in 2000 to $7.0 million, a 20% increase compared to 1999. Additionally, we recorded $1.3 million of capitalized interest during 2000 and no capitalized interest in 1999. Primarily, the increase is attributable to a higher average debenture balance during 2000 compared to 1999. The average debenture balance was $56.6 million during 2000 compared to $41.7 million during 1999. Additionally, interest expense related to escrowed cash in drilling programs increased during 2000 compared to 1999. We raised $46.5 million from our drilling programs during 2000 compared to $40.9 million raised in 1999.

Item 7A: Quantitative and Qualitative Disclosures About Market Risk

Commodity Risk. Our major market risk exposure is the commodity pricing applicable to our natural gas and oil production. Realized commodity prices received for our production are primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to natural gas. The effects of price volatility are discussed in the above "Risk Factors" and volatility is expected to continue. Below is a description of the financial instruments we have used to reduce our exposure to commodity price risk. Since March 31, 2001, we have not employed any commodity hedges, derivatives or embedded derivatives, although we may do so in the future.

During periods through March 31, 2001, we entered into participating collars to hedge natural gas production through March 31, 2001. Below is a summary of the collar arrangements from May 1, 2000 to March 31, 2001. The participating collars were designated as hedges, and realized losses were recognized in marketing revenues when the associated production occurred.

We hedged approximately 180,000 Mcf per month for eleven months with a floor price of $2.50 per Mcf and a ceiling price of $3.55 per Mcf. These participating collars closed with our recording a loss of approximately $2.1 million or $1.21 per Mcf produced for the eleven months referred to above.

Our adoption of SFAS No. 133, as amended, is discussed in Note A to our consolidated financial statements.

Interest Rate Risk. Warren holds investments in U.S. treasury bonds available for sale, which represent securities held in escrow accounts on behalf of the drilling programs and purchasers of certain debentures. Additionally, Warren holds U.S. treasury bonds trading securities, which predominantly represent U.S. treasury bonds released from escrow accounts. The fair market value of these securities will generally increase if the federal discount rate decreases and decrease if the federal discount rate increases. All of our convertible debt has fixed interest rates, so consequently we are not exposed to cash flow or fair value risk from market interest rate changes on this debt.

Financial Instruments & Debt Maturities. Our financial instruments consist of cash and cash equivalents, U.S. treasury bonds, accounts receivable, hedging contracts and other long term liabilities. The carrying amounts of cash and cash equivalents, U.S. treasury bonds, accounts receivables and accounts payable approximate fair value due to the highly liquid nature of these short-term instruments. The fair value of our convertible debt approximates face value.

Inflation and Changes in Prices

The general level of inflation affects our costs. Salaries and other general and administrative expenses are impacted by inflationary trends and the supply and demand of qualified professionals and professional services. Inflation and price fluctuations affect the costs associated with exploring for and producing natural gas and oil, which have a material impact on our financial performance.

Income Taxes

We follow the provisions of SFAS No. 109, "Accounting for Income Taxes," which provides for recognition of a deferred tax liability or asset for deductible temporary timing differences, operating loss carryforwards, statutory depletion carryforwards and tax credit carryforwards net of a valuation allowance. The temporary differences consist primarily of depreciation, depletion, and amortization of intangible drilling costs and our investment basis in oil and gas partnerships.

As of December 31, 2002, we had a net operating loss carryforward of approximately $57 million and no alternative minimum tax credit carry forward. Our net operating loss carryforwards expire in 2012 and subsequent years.

RISK FACTORS

You should carefully consider the risks described below in evaluating our business. Please keep these risks in mind when reading this annual report, any of our other public filings or any of our press releases, including any forward-looking statements appearing in this annual report. See "Forward-Looking Statements." If the events described in any of the following risks actually occur, our business, financial condition or results of operations would likely suffer materially.

Risks Related to Our Business

Reserve estimates depend on many assumptions, the material adverse inaccuracy of which will materially reduce the quantities and present value of our reserves.

This annual report contains estimates of our proved natural gas and oil reserves and the estimated future net revenues from these reserves. These estimates are based upon various assumptions, including assumptions relating to natural gas and oil prices, drilling and operating expenses, capital expenditures, ownership and title, taxes and the availability of funds. The process of estimating natural gas and oil reserves is complex. It requires interpretations of available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise. Further, potential for future reserve revisions, either upward or downward, is significantly greater than normal because most of our reserves are undeveloped.

Actual natural gas and oil prices, future production, revenues, operating expenses, taxes, development expenditures and quantities of recoverable natural gas reserves will most likely vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of future net revenues set forth in this registration statement. A reduction in natural gas and oil prices, for example, would not only reduce the value of proved reserves, but probably would also reduce the amount of natural gas and oil that could be economically produced, thereby reducing the quantity of reserves. We may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing natural gas prices and other factors, many of which are beyond our control.

As of December 31, 2002, approximately 92% of our estimated net proved reserves were undeveloped. Undeveloped reserves, by their nature, are less certain. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we will make significant capital expenditures to develop our reserves. Although we have prepared estimates of our natural gas and oil reserves and the costs associated with these reserves in accordance with industry standards, we cannot assure you that the estimated costs are accurate, that development will occur as scheduled or that the actual results will be as estimated. We may not be able to raise the capital we need to develop these proved reserves. Most of these proved reserves are located in the Wilmington Field in the Los Angeles Basin in California where drilling activities have been suspended since late 1999. Further delays or an unfavorable resolution of our dispute with our joint venture partner in this field could result in a downward revision of our proved reserves. See, "Item 3—Legal Proceedings."

You should not assume that the present value of future net revenues referred to in this registration statement is the current market value of our estimated natural gas and oil reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves are generally based on prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. Any change in consumption by natural gas and oil purchasers or in governmental regulations or taxation will also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of our natural gas and oil properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor nor does it reflect discount factors used in the marketplace for purchase and sale of oil and gas properties. Conditions in the oil and gas industry and oil and gas prices will affect whether the 10% discount factor accurately reflects the market value of our estimated reserves.

We may be unable to continue to obtain needed financing on satisfactory terms to successfully continue operations and grow.

Our future growth depends on our ability to make large capital expenditures for the exploration and development of our natural gas and oil properties and to acquire additional properties. We have projected these capital expenditures to be approximately $10.6 million for 2003. Historically, we have financed our capital expenditures primarily through the drilling programs that participate in the exploration, drilling and development of the projects, and to a lesser extent through debt financing. We intend to continue financing these capital expenditures through drilling programs, the issuance of debt and equity securities, cash flow from operations or a combination of these methods. Future cash flows and the availability of financing will be subject to a number of variables, such as:

- the success of our coalbed methane project in the Washakie Basin;
- our success in locating and producing new reserves;
- the level of production from existing wells; and
- prices of natural gas and oil.

Additional financing sources may be required in the future to fund our developmental and exploratory drilling. Issuing equity securities to satisfy our financing requirements could cause substantial dilution to our existing stockholders. Debt financing could lead to:

- a substantial portion of our operating cash flow being dedicated to the payment of principal and interest;
- our being more vulnerable to competitive pressures and economic downturns; and
- restrictions on our operations.

We incurred a net loss of $7.6 million during 2002. As of December 31, 2002, current liabilities exceeded current assets by $7.8 million. Such loss and working capital deficiency may materially adversely affect our ability to obtain financing. Financing may not be available in the future under existing or new financing arrangements, or we may not be able to obtain necessary financing on acceptable terms, if at all. If sufficient capital resources are not available, we may be forced to curtail our drilling, acquisition and other activities or be forced to sell some of our assets on an untimely or unfavorable basis, which would have an adverse affect on our financial condition and operating results.

Our future growth depends heavily on development of properties in the Washakie Basin in which we own interests.

Our future growth plans rely heavily on establishing significant production and reserves in the Washakie Basin. We cannot be sure, however, that our planned projects in the Washakie Basin will lead to significant production or that we will be able to drill productive wells at anticipated finding and development costs due primarily to financing and environmental uncertainties. Any reduction in our drilling and development plans for the Washakie Basin could result in our failure to replace or add reserves and materially adversely affect our financial condition and results of operations.

An inability to obtain financing at acceptable rates could prevent us from developing the Washakie Basin. Furthermore, environmental restrictions in this area could prevent us from developing this acreage as planned. The BLM has begun preparation of an EIS, which involves a series of scientific studies, surveys and public hearings and formulation of a plan for drilling and production in the Washakie Basin. This study is currently targeted for completion by the end of 2004. Our prior drilling in this basin, along with our projected drilling in 2003, is being conducted under an interim drilling policy of the BLM, under which up to a total of 200 wells can be drilled in this basin, 165 of which have been allocated to us. If public opposition to continued drilling in this basin or other regulatory complications occur, the environmental impact statement may not be completed during 2004, or could cause the BLM to severely restrict or prohibit drilling on a more permanent basis. This could delay or halt our drilling activities or the construction of ancillary facilities necessary for production, which would prevent us from developing our property interests in the Washakie Basin as planned. We cannot predict the future timing or outcome of the environmental impact statement. Delays could severely limit our operations there or make them uneconomic. This could impede our growth, as this is the area in which we intend to undertake significant activity in order to increase our production and reserves.

If we are unable to settle our disagreements with our joint venture partner in the Wilmington Field, the value of our interest there or realization of that value could be significantly diminished or delayed.

A majority, approximately 94% of the estimated present value of our proved reserves at December 31, 2002 are attributable to our interests in the Wilmington Field near Los Angeles, California. Our operations in this field to date have been governed by a joint venture agreement and the purchase and sale agreement with Magness Petroleum Company, which requires a substantial degree of coordination and cooperation with Magness. Our business relationship with Magness has been characterized by significant discord and litigation, and no drilling or development operations have taken place in this field since November 1999. See "Item 3—Legal Proceedings." The ultimate outcome of this litigation, which is continuing, could affect our ownership interest in the Wilmington Field or its value. Continued delays in conducting drilling operations in the Wilmington Field due to litigation with Magness is likely to affect the realization of the value of our interests in that field because most of our proved reserves in this field are undeveloped and require further drilling to become producing reserves. We believe that any subsequent findings will not have a significant adverse effect on our financial position or operations.

Defects in the title to any of our natural gas and oil interests could result in the loss of some of our oil and natural gas properties or portions thereof or liability for losses resulting from defects in the assignment of leasehold rights.

We obtain interests in natural gas and oil properties with varying degrees of warranty of title such as general, special quitclaim or without any warranty. We acquired our interest in the Wilmington Field from an independent operator who acquired the interest directly from Exxon Corporation with no warranty of title at all and no representation as to the percentage working interest or net revenue interest being transferred. We have acquired no title opinion as to the interests we own in that field, which may ultimately prove to be less than the interests we believe we own. Losses in this field may result from title defects or from ownership of a lesser interest than we assume we acquired or from the assignment of leasehold rights by us to our drilling programs. In other instances, title opinions may not be obtained if in our discretion it would be uneconomical or impractical to do so. This increases the possible risk of loss and could result in total loss of properties purchased. Furthermore, in certain instances we may determine to purchase properties even though certain technical title defects exist if we believe it to be an acceptable risk under the circumstances.

The marketability of our production is dependent upon factors over which we have no control.

The marketability of our production depends in part upon the availability, proximity and capacity of pipelines, natural gas gathering systems and processing facilities. This dependence is heightened in our coalbed methane operations where this infrastructure is less developed than in our traditional oil and gas operations. For example, there is no existing pipeline in the southern portion of the Washakie Basin. Therefore, if drilling results are positive in the entire length of the Washakie Basin, an entirely new gathering system would need to be built to handle the potential volume of gas produced at a cost of approximately $10 million, which would likely require Warren to seek the assistance of a substantial pipeline company to finance and construct such a system. In our traditional oil and gas operations, we generally only have to tie in to existing pipelines at a cost of less than $250,000, which can be completed in a number of weeks.

Any significant change in market factors affecting these infrastructure facilities could adversely impact our ability to deliver the natural gas and oil we produce to market in an efficient manner, or its price and, in some cases, we may be required to shut-in wells, at least temporarily, for lack of a market or because of the inadequacy or unavailability of transportation facilities. We deliver natural gas and oil through gathering systems and pipelines that we do not own. These facilities may not be available to us in the future. Our ability to produce and market natural gas and oil is affected and also may be harmed by:

- the lack of pipeline transmission facilities or carrying capacity;
- federal and state regulation of natural gas and oil production;
- federal and state transportation, tax and energy policies;
- changes in supply and demand; and
- general economic conditions.

Leverage materially affects our operations.

As of December 31, 2002, our long-term debt included approximately $54.7 million of debentures, substantially all of which consists of debentures we have issued from time to time with due dates ranging from December 31, 2007 through December 31, 2022. At December 31, 2002, the ratio of our debt to equity was 7.8 to 1.0 and at the same date, the ratio of our debt to total assets was 0.5 to 1.0. Additionally, we are required to make sinking fund payments on $47.9 million principal amount of our outstanding debentures, with sinking fund payments of $3.6 million by the end of 2003 and $3.8 by the end of 2004. We are also contingently obligated to repurchase 10% of our outstanding bonds annually. See the next risk factor below. Although we believe we can meet these requirements through December 31, 2003, we may not have sufficient funds to make repayments or sinking fund payments throughout all future maturities.

Our level of debt affects our operations in several important ways, including the following:

- a large portion of our net cash flow from operations has been used to pay interest on borrowings;
- the covenants contained in the agreements governing our debt limit our ability to borrow additional funds or to dispose of assets;
- the covenants contained in the agreements governing our debt may affect our flexibility in planning for and reacting to changes in business conditions;
- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes; and
- our leveraged financial position may make us more vulnerable to economic downturns and may limit our ability to withstand competitive pressures.

In addition, we may significantly alter our capitalization in order to make future acquisitions or develop our properties. These changes in capitalization may significantly increase our level of debt. A higher level of debt increases the risk that we may default on our debt obligations. Our ability to meet debt obligations and to reduce our level of debt depends on our future performance.

If we are unable to repay our debt at maturity out of cash on hand, we could attempt to refinance the debt or repay the debt with the proceeds of an equity offering. We may not be able to generate sufficient cash flow to pay the interest or principal when due on our debt. We may be unable to sell public debt or equity securities or do so on acceptable terms to pay or refinance the debt. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions and our market value and operations performance at the time of the offering or other financing. Any such offering or refinancing may not be successfully completed.

Our substantial contingent obligations to repurchase 10% of our outstanding bonds and debentures annually and to repurchase drilling program interests could strain our financial resources and adversely affect our future financial condition.

Holders of our $54.7 million of outstanding bonds and debentures are entitled each year to tender up to 10% of the original aggregate face amount of each series of debentures for repurchase by us at their face amount. Up to $5.5 million in 2003 and $5.5 million in 2004.

Furthermore, under the terms of 13 of our drilling programs formed before 1998, investors have the right to require us to repurchase their interests in each program for a formula price either seven years from the date of a partnership's formation, or between the 15th and 25th anniversary of their formation. As of February 28, 2003, our potential repurchase obligations which mature between 2003 and 2007 for such programs approximate up to $11.3 million and for those maturing in 2008 or beyond approximate up to $1.7 million. For the drilling programs formed before 1998, the repurchase price is the amount of an investor's original capital contribution reduced by the greater of:

- cash distributions made to the investor through the repurchase date, or
- 10% for every $1.00 by which the then current oil price is below $13.00 per Bbl, adjusted by CPI changes since the program's formation.

Furthermore, as of December 31, 2002, under the terms of 8 of our drilling programs formed during and after 1998, investors have the right to require us to repurchase their interests in each program for a formula price seven years from the date of a partnership's formation. As of February, 2003, our potential repurchase obligations which mature between 2003 and 2007 for such programs approximate up to $45.7 million and for those maturing in 2008 or beyond approximate up to $54.5 million. For the drilling programs formed in 1998 and thereafter, the repurchase price is the amount of an investor's original capital contribution reduced by the greater of:

- cash distributions made to the investor through the repurchase date, or
- 10% for every $1.00 by which the then current oil price is below $13.00 per Bbl, adjusted by
- CPI changes since the program's formation.

However, under no circumstances will the repurchase price for interests in programs formed in 1998 and thereafter exceed the present value of the program's future net revenues from proved reserves.

As of December 31, 2002, we have made aggregate cash distributions to investors in the drilling programs of approximately $52.6 million. A portion of our repurchase obligations is secured by $4.4 million market value of treasury securities held by an independent trustee.

A reduction in production of oil and/or gas prices could result in our recording liabilities for our repurchase obligations and might result in our having to repurchase certain drilling program interests if tendered by investors. At December 31, 2002, original capital contributions of program investors exceeded cash distributions made to that date by $4.4 million for programs whose rights mature in 2003 and by $16.7 million for programs whose rights mature in 2004. Depending upon the amount of cash distributions to investors in our programs prior to the repurchase obligation dates and the number of investors who tender their interests for repurchase as their tender rights become available, a significant amount of funds may be required for such repurchases, which could put a strain upon our financial resources and otherwise affect our ability to execute our business plan.

We may face significantly increasing water disposal costs in our coalbed methane drilling operations.

The DEQ has restrictive regulations applying to the surface disposal of water produced from our coalbed methane drilling operations. We typically obtain permits to use surface discharge methods to dispose of water when the groundwater produced from the coal seams will not exceed surface discharge permit limitations. Surface disposal options have volumetric limitations and require an extensive third-party water sampling and laboratory analysis program to ensure compliance with state permit standards. Alternative methods to surface disposal of water are more expensive. These alternatives include installing and operating treatment facilities or drilling disposal wells to re-inject the produced water into the underground rock formations adjacent to the coal seams or lower sandstone horizons. When we are unable to obtain the appropriate permits for surface disposal or applicable laws or regulations require water to be disposed of in an alternative manner, the costs to dispose produced water significantly increases. For example, the approximate cost to dispose of produced water on the surface is $0.01 per barrel, into temporary reservoirs is $0.04 per barrel and into water disposal wells is $0.10 per barrel. These costs could have a material adverse effect on some of our operations in this area, including potentially rendering future production and development in these affected areas uneconomic.

Based on our experience with coalbed methane gas production in the Powder River Basin, we believe that permits for surface discharge of produced water in that basin as well as the Washakie Basin will become more and more difficult to obtain. In Wyoming, produced water is currently injected at three wells and we have obtained permits to drill six more of these underground injection wells. We expect the costs to dispose of produced water to continue to increase and may increase significantly.

If we pursue acquisitions and are unsuccessful at either completing the acquisitions or if completed, realizing benefits, we may suffer losses.

We may pursue acquisitions of businesses or assets of businesses. These businesses may operate in areas or markets in which we may not have any experience. There is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Completion of acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. The acquisition of properties that are substantially different in operating or geologic characteristics or geographic locations from our existing properties, with which we have less experience, could change the nature of our operations and business. We may issue stock that would dilute our current stockholders' percentage ownership in connection with an acquisition. We have limited experience in acquisition activities and may have to devote substantial time and resources to complete any potential acquisitions. In addition, if adequate funds are not available to us on reasonable terms, we may be unable to take advantage of acquisition opportunities.

If the attention of our management team is diverted toward pursuing acquisitions and integrating any acquired business, they will have less time to devote to managing current operations and developing new operations relating to current assets. Achieving the expected benefits from any acquisition will depend in part on the integration of operations, business cultures and personnel in a timely and efficient manner to minimize the risk that the acquisition will result in the loss of key employees and to minimize the diversion of the attention of management. Any completed acquisition or failure to successfully integrate a newly acquired business could result in the loss of our investment, which could be substantial. Moreover, even successful acquisitions may involve investment related expenses and amortization of acquired assets that could adversely affect our operating results.

Our coalbed methane operations could be adversely affected by abnormally poor weather conditions.

Our coalbed methane operations are conducted in areas subject to extreme weather conditions and often in difficult terrain. Primarily in the winter and spring, our operations are often curtailed because of cold, snow and wet conditions. Unusually severe weather could further curtail these operations, including drilling of new wells or production from existing wells, and depending on the severity of the weather, could have a material adverse effect on our financial condition and results of operations.

As general partner of limited partnerships and co-venturer in joint ventures, we are liable for various obligations of those partnerships and joint ventures.

We currently serve as the managing general partner of 24 limited partnerships and participate in four joint ventures as a result of our sponsorship of drilling programs. As general partner or co-venturer, we are contingently liable for the obligations of the partnerships or joint ventures, as applicable, including responsibility for their day-to-day operations, and liabilities which cannot be repaid from partnership or venture assets, insurance proceeds or indemnification by others. In the future, we might be exposed to litigation in connection with partnership or joint venture activities, or find it necessary to advance funds on behalf of certain partnerships or joint ventures to protect the value of the natural gas and oil properties by drilling wells to produce undeveloped reserves or to pay lease operating expenses in excess of production. These activities may adversely affect our financial condition. See "Items 1 and 2—Business and Properties—Drilling Programs."

Our role as general partner of limited partnerships and co-venturer in joint ventures may result in conflicts of interest, which may not be resolved in the best interests of Warren or its stockholders.

Our role as general partner of limited partnerships and co-venturer in the joint ventures may result in conflicts of interest between the interests of those entities and our stockholders. For example, we plan to continue contributing natural gas and oil wells to the various drilling programs we have sponsored. The allocation of those wells to the drilling programs may give rise to a conflict of interest between our interests and the interests of the partners or co-venturers in our drilling programs. The resolution of these conflicts may not always be in our best interests.

The loss of our chief executive officer or other key management and technical personnel or our inability to attract and retain experienced technical personnel could adversely affect our ability to operate.

We depend to a large extent on the efforts and continued employment of Norman F. Swanton, our chief executive officer and chairman, Kenneth Gobble, our senior vice president—exploration and production, Timothy A. Larkin, our senior vice president and chief financial officer, and other key management and technical personnel. The loss of the services of Messrs. Swanton, Gobble, Larkin or other key management and technical personnel could adversely affect our business operations. We maintain key person life insurance on Messrs. Swanton and Larkin but not on other key management and technical personnel.

The success of our development, exploration and production activities depends, in part, on our ability to attract and retain experienced petroleum engineers, geologists and other key personnel. From time to time, competition for experienced engineers and geologists is intense. If we cannot retain these personnel or attract additional experienced personnel, our ability to compete in the geographic regions in which we conduct our operations could be harmed.

Hedging activities may result in losses or limit our potential gains.

While we have not had any hedging arrangements in place to reduce our exposure to fluctuations in the prices of natural gas and oil since March 31, 2001, we may enter into long-term gas contracts and hedging arrangements in the future. These hedging arrangements would expose us to risk of financial loss if certain events were to occur, including the following:

- our production is lower than expected;
- the difference between the underlying price in the hedging agreement and actual prices received is higher or lower than expected;
- the other parties to the hedging contracts fail to perform their contract obligations; or
- a sudden unexpected event materially impacts natural gas or oil prices.

In addition, these hedging arrangements may limit the benefit we would receive from increases in oil or natural gas prices. Furthermore, if we choose not to engage in hedging arrangements in the future, we may be more adversely affected by changes in natural gas and oil prices than other competitors who engage in hedging arrangements. We cannot guarantee the success of any long-term gas contracts or hedging arrangements we may enter into in the future.

We are subject to litigation risks that may not be covered by insurance.

In the ordinary course of business, we become subject to various claims and litigation. The material litigation we are currently involved in is summarized in "Item 3—Legal Proceedings." We maintain insurance to cover potential losses and we are subject to various self-retentions and deductibles under our insurance. It is possible, however, that judgments could be rendered against us that exceed policy limits or, in cases in which we could be uninsured, beyond the amount that we currently anticipate incurring for such matters.

RISKS RELATING TO THE OIL AND GAS INDUSTRY

Natural gas and oil prices fluctuate widely and a decrease in natural gas or oil prices will adversely affect our financial results.

Our revenues, operating results and future rate of growth are substantially dependent upon the prevailing prices of, and demand for, natural gas and oil. Declines in the prices of, or demand for, natural gas and oil may adversely affect our financial condition, liquidity, ability to finance planned capital expenditures and results of operations. Lower natural gas and oil prices may also reduce the amount of natural gas and oil that we can produce economically. Historically, natural gas and oil prices and markets have been volatile, and they are likely to continue to be volatile in the future. A decrease in natural gas or oil prices will not only reduce revenues and profits, but will also reduce the quantities of reserves that are commercially recoverable and may result in charges to earnings for impairment of the value of these assets. If natural gas or oil prices decline significantly for extended periods of time in the future, we might not be able to generate enough cash flow from operations to meet our obligations and make planned capital expenditures. Natural gas and oil prices are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for natural gas and oil, market uncertainty and a variety of additional factors that are beyond our control. NYMEX pricing for natural gas ranged from $1.91 to $5.34 per Mmbtu during 2002 and from $1.91 to $9.82 per Mmbtu during 2001. NYMEX pricing for oil ranged from $17.97 to $32.72 per Bbl during 2002 and from $17.45 to $32.19 per Bbl during 2001. Among the factors that cause this fluctuation are:

- domestic and worldwide supplies of natural gas and oil;
- market expectations about future prices;
- the availability of pipeline capacity;
- political conditions in natural gas and oil producing regions;

- overall economic conditions;
- domestic and foreign governmental regulations and taxes;
- the price and availability of alternative fuels;
- weather conditions; or
- levels of production, and other activities of OPEC members and other oil and natural gas producing nations.

We may not be able to replace, maintain or expand our reserves.

In general, production from natural gas and oil properties declines over time as reserves are depleted, with the rate of decline depending on reservoir characteristics. If we are not successful in our exploration, development and enhancement activities or in acquiring properties containing proved reserves, our proved reserves will decline as reserves are produced. Our future natural gas and oil production is highly dependent upon our ability to economically find, develop or acquire reserves in commercial quantities.

To the extent cash flow from operations is reduced, either by a decrease in prevailing prices for natural gas and oil or an increase in finding and development costs, and external sources of capital become limited or unavailable, our ability to make the necessary capital investment to maintain or expand our asset base of natural gas and oil reserves would be impaired. Even with sufficient available capital, our future exploration and development activities may not result in additional proved reserves and we may not be able to drill productive wells at acceptable costs.

Oil and gas exploration and development is a high-risk activity.

Our future success depends largely on the success of our exploratory and development drilling activities, which involve numerous risks, including the risk that we will not find any commercially productive natural gas or oil reservoirs. The cost of drilling, completing and operating wells is often uncertain, and a number of factors can delay or prevent drilling operations, including:

- unexpected drilling conditions;
- pressure or geologic irregularities in formations;
- equipment failures or accidents;
- pipeline and processing interruptions or unavailability;
- production allocations;
- adverse weather conditions;
- lack of market demand;
- government regulations;
- shortages or delays in the availability of drilling rigs and the delivery of equipment; and
- force majeure.

Our future drilling activities may not be successful. Our drilling success rate overall and within a particular area could decline. We could incur losses by drilling unproductive wells. Also, we may not be able to obtain any options or lease rights in potential drilling locations. Although we have identified numerous potential drilling locations, we cannot be sure that we will ever drill them or that we will produce natural gas or oil from them or from any other potential drilling locations. Shut-in wells, curtailed production and other production interruptions may negatively impact our business and result in decreased revenues.

Competition in the oil and gas industry is intense, and many of our competitors have greater financial, technological and other resources than we do.

We operate in the highly competitive areas of oil and gas exploration, development and acquisition with a substantial number of other companies. We face intense competition from independent, technology-driven companies as well as from both major and other independent oil and gas companies in each of the following areas:

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

Many of our competitors have financial, managerial, technological and other resources substantially greater than ours. These companies may be able to pay more for exploratory prospects and productive oil and gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. To the extent our competitors are able to pay more for properties than we are, we will be at a competitive disadvantage. Further, many of our competitors may enjoy technological advantages and may be able to implement new technologies more rapidly than we can. Our ability to explore for natural gas and oil prospects and to acquire additional properties in the future will depend upon our ability to successfully conduct operations, implement advanced technologies, evaluate and select suitable properties and consummate transactions in this highly competitive environment.

We are subject to complex laws and regulations, including environmental regulations, that can adversely affect the cost, manner or feasibility of doing business.

Exploration for and exploitation, production and sale of oil and gas in the United States is subject to extensive federal, state and local laws and regulations, including complex tax laws and environmental laws and regulations. Failure to comply with these laws and regulations may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Compliance costs are significant. Further, these laws and regulations, particularly in the Rocky Mountain region, could change in ways that substantially increase our costs and associated liabilities. We cannot be certain that existing laws or regulations, as currently interpreted or reinterpreted in the future, or future laws or regulations will not harm our business, results of operations and financial condition. Matters subject to regulation include:

- water discharge permits for drilling operations;
- drilling permits;
- drilling bonds;
- spacing of wells;
- unitization and pooling of properties;
- air quality;
- rights of way;
- environmental protection;
- reports concerning operations; and
- taxation.

Under these laws and regulations, we could be liable for:

- personal injuries;
- property damage;
- oil spills;
- discharge of hazardous materials;
- well reclamation costs;
- remediation and clean-up costs; and
- other environmental damages.

See "Items 1 and 2—Business and Properties—Government Regulation" for a more detailed discussion of laws affecting our operations.

Shortages of rigs, equipment, supplies, and personnel may restrict our operations from time to time.

If domestic drilling activity increases, particularly in the fields in which we operate, a general shortage of drilling and completion rigs, field equipment and qualified personnel could develop. These shortages could be intense. If shortages do occur, the costs and delivery times of rigs, equipment and personnel could be substantially greater than in previous years. From time to time, these costs have sharply increased and could do so again. The demand for and wage rates of qualified drilling rig crews generally rise in response to the increasing number of active rigs in service and could increase sharply in the event of a shortage. Shortages of drilling and completion rigs, field equipment or qualified personnel could delay, restrict or curtail our exploration and development operations, which could in turn harm our operating results.

We do not insure against all potential operating risks and loss. We could be seriously harmed by unexpected liabilities.

Our operations are subject to hazards and risks inherent in drilling for, producing and transporting natural gas and any of these risks can cause substantial losses resulting from:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

As protection against operating hazards, we maintain insurance coverage against some, but not all, potential losses. However, losses could occur for uninsurable or uninsured risks, or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could harm our financial condition and results of operations. In addition, pollution and environmental risks generally are not fully insurable.

RISKS RELATED TO OWNERSHIP OF OUR COMMON STOCK

No public trading market exists for our common stock.

There is no public trading market for our common stock and there can be no assurance that a trading market will ever develop. We cannot predict nor control the extent to which a trading market will develop or how liquid such a market may become. Shares of our common stock may only be resold if they are registered with the SEC or if they are sold pursuant to an exemption from registration.

The number of shares eligible for future sale or which have registration rights could adversely affect any future market that develops for our common stock.

If a public market for our shares should develop, sales of substantial amounts of our common stock in such a public market or the perception that a large number of shares are available for sale could depress any market price for our common stock. As of December 31, 2002, there were approximately 17,581,996 shares of common stock outstanding and 7,283,362 shares of common stock issuable upon the exercise of outstanding options and conversion of our convertible debt. Pursuant to Rule 144 under the Securities Act, commencing March 26, 2002, which was 90 days following the effectiveness of our Form 10 registration statement, up to approximately 9,666,547 shares of our common stock could thereafter be sold under Rule 144 and 7,871,032 shares including 6,045,949 shares held by "affiliates" could be resold subject to the volume limitations of Rule 144. Further, pursuant to Rule 144, commencing March 26, 2002, all holders of our common stock issuable upon conversion of existing convertible debt were eligible to sell such shares, and some of them may also have rights, subject to some conditions including the consent of any underwriter, to include their shares in any registration statements that we file to register our shares under the Securities Act for ourselves or other stockholders. Commencing January 1, 2004, under the registration rights agreement dated December 12, 2002, holders of approximately 3,212,317 shares of our convertible preferred shares as of March 19, 2003, which will be issued on or around March 31, 2003 as part of the next closing, have a one time right to demand that up to 3,212,317 shares of common stock issuable upon conversion of the convertible preferred shares be registered under the Securities Act. Additionally, the holders may have right to include those 3,212,317 shares of common stock, subject to the consent of any underwriter, to include their shares in registration statements that we may file, if any, to register shares of our common stock under the Securities Act for ourselves or other shareholders. If our stockholders sell significant amounts of common stock on any public market which develops or exercise their registration rights and sell a large number of shares, the price of our common stock could be negatively affected. If we were to include shares held by those holders in a registration statement pursuant to the exercise of their registration rights, those sales could impair our ability to raise needed capital by depressing the price at which we could sell our common stock or impede such an offering altogether.

Our inability to obtain waivers or releases of preemptive rights from some of our current and former stockholders in connection with previous issuances of securities while we were a New York corporation may subject us to liability for damages.

We reincorporated from the state of New York into the state of Delaware on September 5, 2002. The laws of the State of Delaware and our Delaware certificate of incorporation do not provide for shareholders to have preemptive rights. Because we were originally incorporated in New York before February 1998 and our former certificate of incorporation did not deny shareholders preemptive rights, our shareholders while were a New York corporation may have preemptive rights in connection with certain issuances of our securities, unless certain exceptions applied. Generally, if applicable, preemptive rights entitle a shareholder to subscribe to a proportionate part of a new issue of stock, securities convertible into stock or rights to acquire stock. On numerous occasions between 1992 and 2000, we issued common stock, warrants and convertible bonds. We may not have informed our shareholders regarding their preemptive rights under New York law, if not exempt or otherwise waived, relating to these offerings.

We have obtained written waivers or releases from shareholders who, collectively, represented a majority of the outstanding shares as of December 31, 2000, and owned shares for many years before then. We have not determined whether or not we will seek additional waivers. If we do determine to seek such waivers, we are uncertain whether or not we will be able to obtain waivers from a substantial additional number of those persons or entities who owned our stock at the time of the issuances of securities between 1992 and 2000. A shareholder who has not waived his or her preemptive rights while we were a New York corporation with respect to our former offering of securities that were not otherwise exempt may have a right to bring an action for damages against us. If claims are made and are successful, damages could be assessed against us. Our financial condition could be materially adversely affected if any such assessment involves substantial damages.

Control by our officers and directors stockholders will limit your ability to influence the outcome of matters requiring stockholder approval and could discourage our potential acquisition by third parties.

Our executive officers and directors beneficially own, in the aggregate, approximately 24% of our outstanding common stock. These stockholders, if acting together, would be able to influence significantly all matters requiring approval by our stockholders, including the election of our board of directors and the approval of mergers or other business combination transactions. This concentration of ownership could have the effect of delaying or preventing a change in our control or otherwise discourage a potential acquirer from attempting to obtain control of us, which in turn could have an adverse effect on the market price of our common stock or prevent our stockholders from realizing a premium over the market price for their shares of our common stock.

Item 8: Financial Statements and Supplementary Data

See Independent Accountant's Report and Audited Financial Statements at Item 15 for financial statements.

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

None.

PART III

Item 10: Directors and Executive Officers of the Registrant.

Executive Officers, Directors and certain Significant Employees

Our executive officers, directors and certain significant employees and their ages and positions are set forth below:

Name	Age	Position
Norman F. Swanton	65	President, Chairman of the Board and Chief Executive Officer
Timothy A. Larkin	40	Senior Vice President and Chief Financial Officer
David E. Fleming	48	Senior Vice President, General Counsel and Corporate Secretary
Ellis G. Vickers	46	Senior Vice President—Land Management & Regulatory Affairs and Associate General Counsel
Kenneth A. Gobble	43	Senior Vice President—Exploration & Production
Jack B. King	58	Vice President and National Director of Sales and Marketing
Dominick D'Alleva(3)	51	Director
Anthony L. Coelho(2)(3)	60	Director
Lloyd G. Davies (1)(2)	66	Director
Marshall Miller(1)(2)	52	Director
Thomas G. Noonan(1)	64	Director
Michael R. Quinlan(3)	58	Director

(1) Members of the Compensation Committee.

(2) Members of the Audit Committee.

(3) Members of Corporate Governance Committee.

Norman F. Swanton. Mr. Swanton is and has been our President, Chairman of the Board and Chief Executive Officer since Warren Resources, Inc. was founded in June 1990. Mr. Swanton currently serves on the board of directors for Resource Capital Group, Inc., a public company with its principal business in real estate. From October 1986 to 1990, he served as an independent financial advisor, arranging debt restructuring, new credit facilities, leveraged buy-out financing, debt-for-equity exchanges, equity financing, reorganization consulting and providing other financial services. From 1972 to 1985, he served as Chairman of the Board, President and Chief Executive Officer of Swanton Corporation, a publicly held company engaged in investment banking, securities brokerage, insurance premium financing, securities industry consulting and energy operations; Chairman of the Board and founder of NFS Services, Inc., a corporation engaged in providing credit, operations and regulatory consulting; Chairman of the Board of Swanton, Shoenberg Hieber, Inc., a New York Stock Exchange member firm; Chairman of the Board of Swanton Swartwood Hess, Inc., a NASD member firm; and President and founder of Low Sulphur Fuel Company, a marine terminal residual fuel oil blending operation combined with crude oil-for-product exchange activities on behalf of West Coast utility companies. From 1961 to 1972, he served as an executive officer for Glore, Forgan, Staats, Inc. and a divisional controller for Hayden Stone, Inc. which were New York Stock Exchange member securities and underwriting firms. He also served as a principal consultant to the Trust Fund of the New York Stock Exchange serving as its representative in the liquidation of several former New York Stock Exchange member firms. Mr. Swanton received his Bachelor of Arts Degree with honors in History and Political Science from Long Island University in 1962 and attended Bernard Baruch Graduate School of Business in a graduate degree program in Accountancy and Finance from 1963 to 1966. He is the brother-in-law of Thomas G. Noonan.

Timothy A. Larkin. Mr. Larkin has served as our Senior Vice President and Chief Financial Officer since January 1995. From 1991 to 1994, he served as Accounting Manager of Palmeri Fund Administrators, Inc., an administrative services company providing investment, administrative and accounting advisory support to over 50,000 limited partners in investment funds primarily sponsored by Merrill Lynch and Oppenheimer & Co. Inc. From 1985 to 1991, he was employed in the audit department of Deloitte & Touche, LLP, an international public accounting firm, attaining the level of audit manager. Mr. Larkin received his bachelor's degree in Accounting from Villanova University in 1985.

David E. Fleming. Mr. Fleming joined Warren in July 2001 as a Senior Vice President and General Counsel. In September 2002, Mr. Fleming was also elected our Corporate Secretary. From January 1999 to June 2001, he was a partner with the law firm of Cummings & Lockwood, where he practiced corporate and securities law. For the five years prior thereto, he practiced corporate law at Epstein, Becker & Green, P.C., New York, New York, where he was a member of the firm and currently maintains Of Counsel status. Mr. Fleming does not provide any legal services to the Company on behalf of Epstein, Becker & Green, P.C. Mr. Fleming received a Bachelor of Arts degree from Cornell University in 1976 and a Juris Doctor, Cum Laude, from the University of Maryland School of Law in 1980. He is admitted to practice law in the states of New York, Connecticut and Maryland.

Ellis G. Vickers. Mr. Vickers became our Senior Vice President—Land Management & Regulatory Affairs in January 2003. From September 2001 through December 2002, he was Vice President and Associate General Counsel and Senior Vice President and General Counsel of Warren E & P. From 1995 through December 2001, Mr. Vickers practiced law with the New Mexico based law firm of Bozarth & Vickers. He focused his practice on corporate, securities, oil and gas, real estate and partnership law and is a New Mexico Board of Legal Specialization Recognized Specialist in Oil and Gas Natural Resources. Mr. Vickers received his Bachelor of Science degree in Political Science, Summa Cum Laude, from Eastern New Mexico University in 1979 and a Juris Doctor from the University of New Mexico in 1982. He is admitted to practice law in the states of New Mexico and Texas.

Ken Gobble. Mr. Gobble became our Vice President—Exploration & Production in January 2003. From 1996 to December 2002, he was Vice President—Rocky Mountain Region for Warren E & P. Prior to joining Warren E & P in 1996, Mr. Gobble had extensive experience with major service companies including Schlumberger Well Services. Additionally, Mr. Gobble has extensive experience in numerous advanced applications for natural gas and oil drilling operations including logging-while-drilling, wire-line, gamma ray, 3-D seismic, horizontal drilling and coalbed methane development. Mr. Gobble received his Bachelor of Science Degree in Petroleum Engineering and a Bachelor of Science Degree in Mathematics from New Mexico Institute of Mining and Technology in 1986.

Jack B. King. Mr. King has served as our Vice President and our National Director of Sales and Marketing for drilling programs and our other private placements since April 1997. He is also our Western Marketing representative based in Tustin, California. From 1995 to April 1997, he served as a marketing director for Icon Capital, an equipment leasing syndicator. He received his Bachelor of Arts degree in Psychology from Drury University in Springfield, Missouri in 1966 and holds various securities and insurance licenses.

Dominick D'Alleva. Mr. D'Alleva was our Secretary until September 2002 and has been a director since June 1992. He serves on the corporate governance committee of the Board. Additionally, from 1995 to the present, he has been a principal with D and D Realty Company, LLC, a privately owned New York limited liability company involved in the acquisition and financing of real estate. From 1986 to 1995, he was engaged in residential New York City real estate for his own account and as general counsel to various real estate acquisition firms, where he negotiated contracts for the acquisition and financing of commercial real estate. From 1983 to 1985, he served as Executive Vice President, Director and General Counsel of Swanton Corporation, which engaged in energy, retail and financial services businesses. From 1980 to 1983 he was Associate Counsel of Damson Oil Corporation. From 1977 to 1980 he was an associate with Simpson, Thatcher & Bartlett specializing in securities and corporate law. Mr. D'Alleva received a Bachelor of Arts degree Summa Cum Laude from Fordham University in 1974 and earned his Juris Doctor degree with honors from Yale University in 1977.

Anthony L. Coelho. Congressman Coelho joined our Board as an independent director in May 2001 and serves on the audit and corporate governance committees of the Board. From December 2000 to the present, Mr. Coelho has devoted his time to serving on the boards of directors listed below and as an independent consultant and adviser. From 1998 through November 2000, he served as the General Chairman for the U.S. Presidential campaign of Vice President Al Gore. From 1995 to 1998, he was Chairman and Chief Executive Officer of ETC w/tci, Inc, an education and training technology company in Washington, D.C. and from 1990 to 1995, he served as President and CEO of Wertheim Schroeder Investment Services, Inc. From 1978 to 1989, he served five terms in the U.S. Congress, representing the State of California as a member of the U.S. House of Representatives. During his congressional terms, he served as Democratic Majority Whip from 1987 to 1989 and authored the Americans with Disabilities Act. Congressman Coelho was also appointed chairman of the President's Committee on the Employment of People with Disabilities by President Clinton. Congressman Coelho has served on a number of corporate boards, including AutoLend Group, Kaleidoscope Network, Inc., LoanNet, LLC, Pinnacle Global Group, Inc. and as chairman of ICF Kaiser International, Inc. He currently serves on the boards of ColumbusNewport, LLC, Cadiz, Inc., Cyberonics, Inc., DeFrancesco & Sons, Inc., Kistler Aerospace Corporation, Ripplewood Holdings, LLC, Service Corporation International, a publicly traded company, and MangoSoft, Inc. Congressman Coelho earned a Bachelor of Arts degree in Political Science from Loyola Marymount University in 1964.

Lloyd G. Davies. Mr. Davies joined the board of directors in July 2001 and serves on the audit committee and compensation committee of the Board.. For the past seven years Mr. Davies has been retired. From 1992 through 1994, Mr. Davies was the Assistant Division Manager for the Western U.S. area for Texaco. Prior to that, from 1990 through 1992, Mr. Davies was the Manager and Director of Operations for Texaco's Far East Operations Division. During those years, he also served on several of Texaco's subsidiaries' board of directors in the Far East. Mr. Davies received a Bachelor of Science Degree in Petroleum Engineering from the University of Oklahoma in 1958. In 1966, he received a Master of Science Degree in Petroleum Engineering with a Minor in Math from the University of Texas.

Marshall Miller. Mr. Miller joined the Board as an independent director in February 1998 and serves on the audit committee and compensation committee of the Board. Mr. Miller was an Executive Vice President of Wells Fargo Bank in San Francisco until retiring in 2000. For the past 17 years, Mr. Miller served in various senior management capacities with several financial institutions including Fair, Isaac Companies, Providian Financial Corporation and Wells Fargo Bank and specialized in advanced computer systems for credit risk management. Mr. Miller received a Bachelor of Arts Degree in Mathematics from the University of California at Berkley and a Masters of Science Degree from Stanford University in 1976.

Thomas G. Noonan. Mr. Noonan joined the Board as a director in November 1997 and serves on the compensation committee of the Board. For the past 17 years, he has served as Manager of Quality Assurance for Mars Inc., an international food and candy company. From 1961 to 1979, he was a microbiologist for the Environmental Department of the State of New York. Mr. Noonan received a Bachelor of Science degree from Fordham University in New York in 1959. He is the brother-in-law of Mr. Swanton.

Michael R. Quinlan. Mr. Quinlan joined the Board as a director in January 2002 and serves on the corporate governance committee of the Board. From 1963 to the present Mr. Quinlan has been employed by the McDonald's Corporation. In 1979, Mr. Quinlan was appointed to the board of directors of McDonald's and served as the Chairman of the Board and Chief Executive Officer from 1990 to 1998. From 1998 to 1999, he served as Chairman of the Board of McDonald's Corporation. From 1987 to 1990, he served as the President and Chief Executive Officer. Currently he serves as the Chairman of the Executive Committee. Mr. Quinlan is chairman of the board of trustees of both Ronald McDonald House Charities and Loyola University Chicago. Additionally, he is a member of the board of trustees of Loyola University Health System. He is also on the board of directors of Dun and Bradstreet Corporation and the May Department Stores Company. Mr. Quinlan earned a Bachelor of Science degree in 1967 and a Master's of Business Administration from Loyola University Chicago in 1970. He has been awarded Honorary Doctors of Law Degrees from Loyola University Chicago, Elmhurst College and Illinois Benedictine College.

Corporate Governance

Warren has always taken the issue of corporate governance seriously. The Board is comprised of a majority of independent directors and the Audit Committee and the Compensation Committee have each been comprised entirely of independent directors since their inception.

The board of directors has established the following standing committees: audit, compensation and corporate governance.

Audit Committee. The audit committee is comprised entirely of non-employee directors. The audit committee reviews the preparation of and the scope of the audit of our annual consolidated financial statements, reviews drafts of such statements, makes recommendations as to the engagement and fees of the independent auditors, and monitors the functioning of our accounting and internal control systems by meeting with representatives of management and the independent auditors. This committee has direct access to the independent auditors and counsel to Warren and performs such other duties relating to the maintenance of the proper books of account and records of Warren and other matters as the board of directors may assign from time to time. We intend to maintain an audit committee consisting of at least three independent directors. Independent directors are persons who are, among other things, neither officers nor employees of Warren or its subsidiaries or any other person who has a relationship with any person or entity which, in the opinion of the board of directors, would interfere with the exercise of independent judgment in carrying out the responsibilities of a director. The Audit Committee consists of Messrs. Miller, Congressman Coelho and Mr. Davies. Mr. Miller currently acts as chairman of the audit committee.

Compensation Committee. The compensation committee consists of Messrs. Davies, Miller and Noonan. Mr. Noonan will be the chairman of the committee. The compensation committee has sole authority to administer our stock option plans. The compensation committee also reviews and makes recommendations regarding the compensation levels of the company's executive officers.

As a result of the recent enactment of the Sarbanes-Oxley Act of 2002 and proposed New York Stock Exchange ("NYSE") and Nasdaq Stock Market, Inc. ("Nasdaq") rules, in March 2003 the Board appointed an independent Corporate Governance Committee and has adopted written charters for all three independent committees that provide, among other things, for an annual self-evaluation. In addition, the Board has adopted (1) a Code of Business Conduct, and (2) a Code of Ethics for the Senior Financial Officers.

Corporate Governance Committee. In March 2003, the Board appointed Messrs. Quinlan, D'Alleva and Coelho as members of the Corporate Governance Committee, with Mr. Quinlan as serving as chairman.

The purposes of the Corporate Governance Committee include without limitation to:

- assist the Board in identifying qualified individuals to become directors;
- recommend to the Board qualified director nominees for election at the stockholders' annual meeting;
- determine membership on the Board committees;
- recommend Corporate Governance guidelines;
- conduct annual self-evaluations of the Board and the Corporate Governance Committee; and
- report annually to the Board on the Chief Executive Officer succession plan.

The Charter of the Corporate Governance Committee can be found on our website at www.warrenresourcesinc.com.

Code of Business Conduct for All Directors, Officers and Employees

The Board has adopted a Code of Business Conduct for all directors, officers and employees. It is the responsibility of every Company director, officer and employee to maintain a commitment to high standards of conduct and ethics. It is the intent of the Code of Business Conduct to inspire continuing dedication to the fundamental principles of honesty, loyalty, fairness and forthrightness. There shall be no waiver of any part of this Code for any director or officer except by a vote of the Board of Directors or a designated Board committee that shall ascertain whether a waiver is appropriate under all the circumstances. In case a waiver of this Code is granted to a director or officer, the notice of such waiver shall be posted on our website at www.warrenresourcesinc.com. A copy of the Code of Business Conduct is available on our website at www.warrenresourcesinc.com.

Code of Ethics for Senior Financial Officers

The Board has also adopted a separate Code of Ethics for our Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer ("Senior Financial Officers' Code"). Each of the covered officers has to certify on an annual basis that the officer shall:

- Act with honesty and integrity, avoiding actual or apparent conflicts of interest in personal and professional relationships.
- Provide constituents with information that is accurate, complete, objective, relevant, timely and understandable.
- Comply with all applicable laws, rules and regulations of federal, state and local governments, and other appropriate private and public regulatory agencies.
- Act in good faith, responsibly, with due care, competence and diligence, without misrepresenting material facts or allowing the officer's independent judgment to be subordinated.
- Respect the confidentiality of information acquired in the course of business except when authorized or otherwise legally obligated to disclose the information, acknowledging that confidential information acquired in the course of business is not to be used for personal advantage.
- Proactively promote ethical behavior among employees at Warren and as a responsible partner with industry peers and associates.
- Maintain control over and responsibly manage all assets and resources employed or entrusted to the officer by Warren.
- Report illegal or unethical conduct by any director, officer or employee that has occurred, is occurring or may occur, including any potential violations of the Senior Officers' Code or the Code of Business Conduct.

There shall be no waiver of any part of the Senior Financial Officers' Code except by a vote of the Board of Directors or a designated Board committee that shall ascertain whether a waiver is appropriate under all the circumstances. In case a waiver of the Senior Financial Officers' Code is granted, the notice of such waiver shall be posted on our website at www.warrenresourcesinc.com. A copy of the Senior Financial Officers' Code that has been adopted by the Board of Directors is attached to this Annual Report as Exhibit 14 and is available on our website at www.warrenresourcesinc.com.

Meetings of the Board of Directors

During 2002, the board of directors met four times. At least 80% of the directors attended each meeting.

Compensation of Directors

Directors who are also employees of Warren receive no additional compensation for their services as directors. Directors who are not employees of Warren receive $1,000 for each meeting of the board of directors or committees of the board of directors which they attend, and are reimbursed for travel expenses and other out-of-pocket costs incurred in connection with the attendance at such meetings. Until Warren becomes a publicly traded company, each director receives:

- options to purchase 25,000 shares of our common stock exercisable at the then current fair market price for a period of five years upon becoming a member of the board; and
- options to purchase 10,000 shares of our common stock for each year of service thereafter, exercisable at the then current fair market price for a period of five years.

After Warren becomes a publicly traded company, each non-employee director shall receive:

- an annual retainer fee of $10,000;
- options to purchase 10,000 shares of our common stock exercisable at the then current fair market price for a period of five years, upon becoming a member of the board; and
- options to purchase 5,000 shares of our common stock for each year of service thereafter, exercisable at the then current fair market price for a period of five years.

Compensation Committee Interlocks and Insider Participation

None of the members of our compensation committee are currently or have been at any time since our founding, an officer or employee of Warren. No member of our compensation committee serves as a member of the board of directors or compensation committee of any entity that has one or more executive officers serving as a member of our board of directors or compensation committee.

Item 11: Executive Compensation.

The following table sets forth the total compensation earned by our chief executive officer and each of the four most highly compensated other executive officers who received annual compensation in excess of $100,000 for the year ended December 31, 2002. We refer to these officers as our named executive officers. The compensation set forth in the table below for the fiscal years ended December 31, 2002, 2001 and 2000 does not include medical, group life or other benefits which are available to all of our salaried employees, and perquisites and other benefits, securities or property which do not exceed the lesser of $50,000 or 10% of the person's salary and bonus shown in the table.

Summary Compensation Table

		Annual Compensation			Long-Term Compensation Awards	
Name and Principal Position	Year	Salary	Bonus(1)	Other Annual Compensation(2)	Securities Underlying Options	All Other Compensation
Norman F. Swanton,	2002	$375,000	$187,500	$16,274	-0-	-0-
Chief Executive Officer and Chairman of	2001	375,000	220,000	$18,814	600,000(3)	-0-
the Board	2000	150,000	375,000	-0-	-0-	-0-
Timothy A. Larkin,	2002	$200,000	$100,000	$ 819	-0-	-0-
Senior Vice President and Chief	2001	185,000	92,500	$ 819	676,875(3)	-0-
Financial Officer	2000	155,000	134,333	-0-	-0-	-0-
David E. Fleming	2002	$210,000	$105,000	-0-	-0-	-0-
Senior Vice President, General Counsel and Secretary	2001	105,000	26,250	-0-	150,000(3)	-0-
Ellis Vickers	2002	$210,000	$105,000	-0-	-0-	-0-
Senior Vice President—Land Management & Regulatory Affairs and Associate General Counsel	2001	105,000	26,250	-0-	150,000(3)	-0-
Jack B. King	2002	$200,000	-0-	-0-	-0-	-0-
Vice President and Director of National	2001	200,000	-0-	-0-	380,630(3)	-0-
Sales And Marketing	2000	150,000	346,186	-0-	-0-	-0-

(1) Bonus amounts reported for 2002, 2001 and 2000 include bonuses earned in the reported year and actually paid in the subsequent year.

(2) Amounts reflect insurance premiums paid by the company during the covered fiscal year with respect to life insurance for the benefit of the named executive officer or his designee.

(3) On October 1, 2002, in order to improve our capital structure senior management and other employees voluntarily surrendered to the company and terminated 2,255,783 stock options issued in 2001 that were exercisable at $10.00 per share through September 4, 2006.

Option Grants in Last Fiscal Year

No stock options to purchase shares of our common stock were granted to the named executive officers during the fiscal year ended December 31, 2002.

Employment Agreements

We entered into an employment agreement on July 1, 2001 with Mr. Norman F. Swanton, our Chairman and Chief Executive Officer, that provides for a salary of $375,000 per year, guaranteed annual bonus compensation equal to 50% of his annual base salary, participation in our standard insurance plans for our executives, and participation in our other incentive compensation programs at the discretion of the board of directors. The employment agreement also provides that all stock options held by Mr. Swanton are subject to accelerated vesting in the event of his termination without cause or in the event of a change of control. Under his employment agreement, Mr. Swanton is entitled to receive stock options to purchase 600,000 shares of common stock at the exercise price of $10.00 per share for a period expiring five years from date of issuance. On October 1, 2002, in order to improve the capital structure of the company, Mr. Swanton voluntarily surrendered and terminated his 600,000 stock options. If Mr. Swanton's employment is terminated without cause, Mr. Swanton is entitled to termination compensation equal to the greater of two years annual base salary, plus the bonus amount paid in the preceding fiscal year, or all of the base salary for the remainder of the employment term, plus the preceding year's bonus compensation. Mr. Swanton's employment agreement automatically renews on each anniversary of the effective date after the initial three year employment term, for an additional one year unless we notify Mr. Swanton in writing 90 days prior to such anniversary that we will not be renewing his employment agreement.

We entered into an employment agreement on July 1, 2001 with Mr. Timothy A. Larkin, our Senior Vice President and Chief Financial Officer, that provides for a salary of $185,000 per year, guaranteed annual bonus compensation equal to 50% of his annual base salary, participation in our standard insurance plans for our executives, and participation in our other incentive compensation programs at the discretion of the board of directors. The employment agreement also provides that all stock options held by Mr. Larkin are subject to accelerated vesting in the event of his termination without cause or in the event of a change of control. Under his employment agreement, Mr. Larkin is entitled to receive stock options to purchase 676,875 shares of common stock at the exercise price of $10.00 per share for a period expiring five years from date of issuance. On October 1, 2002, in order to improve the capital structure of the company, Mr. Larkin voluntarily surrendered and terminated his 676,875 stock options. If Mr. Larkin's employment is terminated without cause, Mr. Larkin is entitled to termination compensation equal to the greater of two years annual base salary, plus the bonus amount paid in the preceding fiscal year, or all of the base salary for the remainder of the employment term, plus the preceding year's bonus compensation. Mr. Larkin's employment agreement automatically renews on each anniversary of the effective date after the initial three year employment term, for an additional one year unless we notify Mr. Larkin in writing 90 days prior to such anniversary that we will not be renewing his employment agreement.

We entered into an employment agreement on June 25, 2001 with Mr. David E. Fleming, our Senior Vice President and General Counsel, that provides for a salary of $210,000 per year, guaranteed annual bonus compensation equal to 50% of his annual base salary, participation in our standard insurance plans for our executives, and participation in our other incentive compensation programs at the discretion of the board of directors. The employment agreement is for an initial three-year term and also provides that all stock options held by Mr. Fleming are subject to accelerated vesting in the event of his termination without cause or in the event of a change of control. Under his employment agreement, Mr. Fleming is obligated to devote sixty (60%) percent of his business time to the performance of his duties and responsibilities to Warren. Mr. Fleming is entitled to receive stock options to purchase 150,000 shares of common stock at the exercise price of $10.00 per share for a period expiring five years from date of issuance. However, on October 1, 2002, in order to improve the capital structure of the company, Mr. Fleming voluntarily surrendered and terminated his 150,000 stock options. If Mr. Fleming's employment is terminated without cause, Mr. Fleming is entitled to termination compensation equal to the greater of two years annual base salary, plus the bonus amount paid in the preceding fiscal year, or all of the base salary for the remainder of the employment term, plus the preceding year's bonus compensation. If terminated with or without cause, the officers can maintain all unvested options provided by the equity incentive plan or, at their option, sell them back to us. Mr. Fleming's employment agreement automatically renews on each anniversary of the effective date after the initial three year employment term, for an additional one year unless we notify Mr. Fleming in writing 90 days prior to such anniversary that we will not be renewing his employment agreement.

We entered into an employment agreement on September 1, 2001 with Mr. Ellis Vickers, our Senior Vice President—Land Management & Regulatory Affairs and Associate General Counsel, that provides for a salary of $210,000 per year, guaranteed annual bonus compensation equal to 50% of his annual base salary, participation in our standard insurance plans for our executives, and participation in our other incentive compensation programs at the discretion of the board of directors. The employment agreement is for an initial three-year term and also provides that all stock options held by Mr. Vickers are subject to accelerated vesting in the event of his termination without cause or in the event of a change of control. Under his employment agreement, Mr. Vickers is entitled to receive stock options to purchase 150,000 shares of common stock at the exercise price of $10.00 per share for a period expiring five years from date of issuance. On October 1, 2002, in order to improve the capital structure of the company, Mr. Vickers voluntarily surrendered and terminated his 150,000 stock options. If Mr. Vickers's employment is terminated without cause, Mr. Vickers is entitled to termination compensation equal to the greater of two years annual base salary, plus the bonus amount paid in the preceding fiscal year, or all of the base salary for the remainder of the employment term, plus the preceding year's bonus compensation. If terminated with or without cause, the officers can maintain all unvested options provided by the equity incentive plan or, at their option, sell them back to us. Mr. Vickers' employment agreement automatically renews on each anniversary of the effective date after the initial three year employment term, for an additional one year unless we notify Mr. Vickers in writing 90 days prior to such anniversary that we will not be renewing his employment agreement.

Employee Benefit Plans

2000 Equity Incentive Plan for Employees of Petroleum Development Corporation

Introduction. Our 2000 Equity Incentive Plan for Employees of Warren E & P was adopted by the board in September 2000 and was amended by the board in September 2001, and approved by our shareholders on September 5, 2002. Any awards granted before shareholder approval of the plan are subject to, and may not be exercised or realized before, approval of the plan by the shareholders. The plan is administered by our compensation committee.

Share Reserve. 1,975,000 shares of common stock have been authorized for issuance under the plan. In addition, no participant in the plan may be granted stock options and direct stock issuances for more than 750,000 shares of common stock in total per calendar year.

Awards. The plan provides for the following types of awards:

- eligible individuals in the employ of, or rendering services to, Warren E & P and its subsidiaries may be granted options to purchase shares of common stock at an exercise price determined by the compensation committee;
- eligible individuals may be issued shares of common stock that may be subject to certain restrictions and conditions directly through the purchase of shares at a price determined by the compensation committee.

Plan Features. The plan will include the following features:

- eligible participants under the plan are employees, consultants and directors of Warren E & P and its subsidiaries.
- the plan sets forth various restrictions upon the exercise of awards. The compensation committee has the discretion to alter any restrictions or conditions upon any awards.
- the exercise price for any options granted under the plan may be paid in cash, by certified or cashier's check or, if acceptable to the compensation committee, in property valued at fair market value, by delivery of a promissory note, or in currently owned shares of common stock valued at fair market value on the last business day prior to the date of exercise. An option may, in the discretion of the compensation committee, be exercised through a sale or loan program with a broker acceptable to the compensation committee without any cash outlay by the optionee.

- grants of restricted stock awards can be made to participants. Restricted stock awards may be subject to certain restrictions, vesting requirements or other conditions, including the attainment of performance goals.
- if a participant's employment is terminated for any reason other than cause, including death or disability, any vested options held by the participant will remain exercisable for a specified period of time after the termination. If a participant's employment is terminated for cause, all outstanding options held by the participant will expire immediately. If a participant's employment is terminated for any reason other than cause, any unvested restricted stock awards will generally be forfeited unless the compensation committee provides otherwise. If a participant's employment is terminated for cause, all restricted stock awards will be forfeited. Warren may require the return of any dividends previously paid on the restricted stock and, in all events, will repay to the participant (or the participant's estate) any amounts paid for the restricted stock awards.

Change in Control. In the event that Warren or Warren E & P is acquired by merger, consolidation, asset sale or equity sale, outstanding options will be assumed, or equivalent options will be issued by the successor corporation. If the successor corporation refuses to assume or substitute the options, the compensation committee may accelerate the participants' rights to exercise for a limited period of time after which the options would terminate. With respect to restricted stock awards, the compensation committee could also elect to terminate any vested awards in exchange for cash payments.

Recapitalization or Reorganization. In the event of a recapitalization or reorganization of Warren or of Warren E & P that does not constitute a change-in-control as described above, a participant will be entitled to receive, upon exercising an option, that which the participant would have received had the participant exercised prior to the recapitalization or reorganization.

Amendment. The board may amend or modify the 2000 Plan at any time, pending any required shareholder approval. The 2000 Plan will terminate no later than September 1, 2010.

As of December 31, 2002, nonqualified stock options to purchase 1,190,000 shares of our common stock were granted to eligible persons pursuant to this plan at exercise prices of $4.00 and $10.00 per share. All of these options are vested. None of these options has been exercised. The shares that may be issued pursuant to the exercise of an option awarded under this plan have not been registered under the Securities Act of 1933.

2001 Stock Incentive Plan

Introduction. Our 2001 Stock Incentive Plan was adopted by the board in September 2001 and approved by our shareholders on September 5, 2002. Any awards granted before shareholder approval of the plan are subject to, and may not be exercised or realized, before approval of the plan by the shareholders. The plan will be administered by our compensation committee.

Share Reserve. A total of 2,500,000 shares of our common stock have been authorized for issuance of options under the plan. In addition, no participant in the plan may be granted stock options, separately exercisable stock appreciation rights, direct stock issuances and stock units for more than 750,000 shares of our common stock in total per calendar year.

Programs. The plan is divided into three separate programs:

- an option grant program under which eligible individuals may be granted options to purchase shares of common stock at an exercise price determined by the compensation committee;
- a stock appreciation rights program under which eligible individuals may be granted rights to receive payments equal to the fair market value of shares of common stock to which the right is subject on the date of exercise over the fair market value of such shares of common stock on the date of grant; and

- a stock issuance program under which eligible individuals may be issued shares of common stock directly through the purchase of shares at a price determined by the compensation committee, or units representing such shares.

Plan Features. The plan includes the following features:

- eligible individuals under the plan are employees, consultants and directors of Warren and our subsidiaries.
- the plan sets forth various restrictions upon the exercise of awards. Our compensation committee has the discretion to accelerate the vesting or exercisability of options under certain events.
- the exercise price for any options granted under the plan may be paid in cash or, if acceptable to the compensation committee, in currently owned shares of common stock valued at fair market value on the exercise date. The option may, in the discretion of the compensation committee, be exercised through a sale or loan program with a broker acceptable to the compensation committee without any cash payment by the option holder.
- deferred compensation stock options may be issued under the stock option program. These options will provide a means by which compensation payments can be deferred to future dates, with the number of shares of common stock subject to a deferred compensation stock option being determined by the compensation committee in accordance with a formula where the number of shares subject to the option is equal to the amount of compensation to be deferred divided by the excess of the fair market value of the common stock at the time of exercise over the exercise price of the option.
- stock appreciation rights may be separately issued entitling a participant to receive an amount equal to the excess of the fair market value of the shares of common stock subject to such right on the date of exercise over the fair market value of such shares on the date of grant. Payment to a participant may be made in: cash, shares of common stock, a deferred compensation option, or any combination of the above, as the compensation committee shall determine.
- outright grants of stock awards, as well as grants of restricted stock awards and restricted stock units can be made to participants. In order for a participant to vest in an award of either restricted stock or a restricted stock unit, the participant must generally provide services for a continuous period of not less than two years. A participant shall be entitled to receive payment for a restricted stock unit in an amount equal to aggregate fair market value of the units covered by the award at the end of the applicable vesting restriction period, which payment can be made in: cash, shares of common stock, deferred compensation stock options, or any combination of the above, as the compensation committee shall determine.
- if a participant's employment is terminated for any reason, including death and disability, any vested awards held by the participant will remain exercisable for a specified period of time after the termination. If a participant retires, but continues or begins to serve as a director, the participant may continue to hold any awards granted under the original terms thereof.

Change in Control. The plan includes change in control provisions which may result in the accelerated vesting of outstanding option grants and stock issuances:

- In the event that Warren is acquired by merger or asset sale or there is an acquisition of more than fifty percent of the capital stock of Warren by an individual, entity or group, the vesting schedule of each outstanding award will be, except to the extent specifically provided to the contrary in the instrument evidencing the award, or any other agreement between a participant and us, accelerated in part so that one-half of the number of shares subject to such award shall become immediately exercisable or realizable and the remaining one-half of such number of shares shall continue to be exercisable or realizable in accordance with the original vesting schedule.

- In the event there is a merger of Warren, or an exchange of shares for cash, securities or other property in connection with an exchange transaction, which does not constitute a change-in-control as described above, the board shall provide that all outstanding options will be assumed or equivalent options substituted by the acquiring or succeeding corporation. With respect to all other awards, the board will determine the effect the transaction will have on such awards at the time the transaction takes place.

Amendment. The board may amend or modify the 2001 Plan at any time, pending any required shareholder approval. The 2001 Plan will terminate no later than September 5, 2011.

On October 1, 2002, in order to improve our capital structure senior management and other employees voluntarily surrendered to the company and terminated stock options issued in 2001 that were exercisable at $10.00 per share through September 4, 2006. As of December 31, 2002, non-qualified stock options to purchase 324,459 shares of our common stock at the exercise price of $10.00 per share have been granted to eligible persons pursuant to this plan. None of these options has been exercised. The shares that may be issued pursuant to the exercise of an option awarded under this plan have not been registered under the Securities Act of 1933.

2001 Key Employee Stock Incentive Plan

Our 2001 Key Employee Stock Incentive Plan was adopted by the board on September 6, 2001 and approved by our shareholders on September 5, 2002. A total of 2,500,000 shares of our common stock have been authorized for issuance under this plan. In addition, no participant in the plan may be granted stock options, separately exercisable stock appreciated rights or direct stock issuances for more than 750,000 shares of common stock in total per calendar year. This plan will be administered by our compensation committee. The plan is modeled after the 2001 Employee Stock Incentive Plan and its terms are substantially similar except that participants eligible to be granted awards under the plan will be limited to our key employees.

On October 1, 2002, in order to improve our capital structure senior management and other employees voluntarily surrendered to the company and terminated stock options issued in 2001 that were exercisable at $10.00 per share through September 4, 2006. As of December 31, 2002, there are no outstanding non-qualified stock options to purchase shares of our common stock pursuant to this plan. The shares that may be issued pursuant to the exercise of any option awarded by this plan have not been registered under the Securities Act of 1933.

Equity Compensation Plan Information

The following table provides information as of December 31, 2002, with respect to shares of our common stock that may be issued under our existing equity compensation plans, all of which have been approved by our shareholders.

	Number of Shares Authorized for Issuance under plan	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
2000 Equity Incentive Plan .	1,975,000	1,190,000	$ 4.65	785,000
2001 Stock Incentive Plan	2,500,000	324,459	$10.00	2,175,541
2001 Key Employee Stock Incentive Plan	2,500,000	-0-	N/A	2,500,000
Total	6,975,000	1,514,459	$ 5.79	5,460,541

Related Matters

A private investigation by the SEC involving events which occurred in the mid to late 1970's was concluded by settlement between Swanton Corporation and certain affiliates, including Mr. Swanton, and the SEC in 1981. As a result of the settlement, Mr. Swanton and Swanton Corporation, without admitting or denying any of the allegations, consented to the entry of a final judgment enjoining them from violations of anti-fraud, periodic reporting and beneficial ownership provisions of the Exchange Act of 1934 and agreed to engage a Special Review Person to determine whether there had been any improper use of corporate funds. The Special Review Person found that, although there was no wrongdoing on the part of Mr. Swanton, $20,400 received by him from an unaffiliated debtor should have been paid to Swanton Corporation. Mr. Swanton thereafter paid the $20,400 to Swanton Corporation.

Item 12: Securities Ownership of Certain Beneficial Owners and Management.

The following table sets forth information regarding the beneficial ownership of our common stock as of March 27, 2003 by:

- each of our directors;
- our chief executive officer;
- our four most highly compensated executive officers other than our chief executive officer; and
- all directors and executive officers as a group.

As of March 27, 2003, we do not know of any other person to own beneficially more than 5% of our common stock.

Unless otherwise indicated, each person named in the table has sole voting power and investment power, or shares this power with his or her spouse, with respect to all shares of our common stock listed as owned by such person. The table includes all shares beneficially owned by each stockholder, which includes any shares as to which the individual has sole or shared voting power or investment power and any shares which the individual has the right to acquire within 60 days of March 27, 2003 through the exercise of any stock option or other right.

Name of Beneficial Owner	Shares of Common Stock Beneficially Owned	Percent of Ownership
Norman F. Swanton(1)(2)	2,504,733	14.3%
Timothy A. Larkin(2)	50,000	*
David E. Fleming(2)	10,000	*
Ellis G. Vickers	-0-	-0-
Dominick D'Alleva(3)	45,521	*
Anthony L. Coelho(3)	-0-	-0-
Lloyd G. Davies(3)	-0-	-0-
Marshall Miller(3)	739,000	4.2%
Thomas G. Noonan(3) (4)	737,333	4.2%
Michael R. Quinlan(3)	78,000	*
All directors and executive officers as a group (10 persons)		

* Less than 1% of the outstanding common stock.

(1) Does not include 361,000 shares of common stock owned by the Swanton Family Trust and 368,000 shares of common stock owned by the Virginia Trust of Eire, as to which Mr. Noonan and his wife are the trustees. The nieces and nephews of Mr. Swanton are the sole beneficiaries of these trusts.

Mrs. Noonan is Mr. Swanton's sister. Includes 50,000 shares owned by a charitable foundation for which Mr. Swanton is a trustee.

(2) Effective on October 1, 2002, in order to improve the capital structure of the company, Mr. Swanton voluntarily surrendered and terminated his previously outstanding 600,000 stock options exercisable at $10.00 per share, Mr. Larkin voluntarily surrendered and terminated his previously outstanding 676,875 stock options exercisable at $10.00 per share, Mr. Fleming voluntarily surrendered and terminated his previously outstanding 150,000 stock options exercisable at $10.00 per share and Mr. Vickers voluntarily surrendered and terminated his previously outstanding 150,000 stock options exercisable at $10.00 per share.

(3) Does not include stock options exercisable at $10.00 per share for a period of five years approved by the compensation committee of the board of directors on September 6, 2001 which grant shall become effective upon approval of the 2001 Stock Incentive Plan by the shareholders as follows: 10,000 for Thomas Noonan; 10,000 for Dominick D'Alleva; 10,000 for Marshall Miller; 25,000 for Anthony Coelho; 25,000 for Lloyd Davies; and 25,000 for Michael Quinlan.

(4) Includes 361,000 shares of common stock owned by the Swanton Family Trust and 368,000 shares of common stock owned by the Virginia Trust of Eire. Mr. Noonan and his wife are the trustees of these trusts. The nieces and nephews of Mr. Swanton are the sole beneficiaries of these trusts. Mr. Noonan disclaims beneficial ownership of the shares of common stock held by the Swanton Family Trust and the Virginia Trust of Eire.

Item 13: Certain Relationships and Related Transactions.

Our officers and directors own, in the aggregate, limited partnership interests valued at $2,788,333 at the time of purchase in 15 of our drilling programs. Mr. Swanton owns $528,333 of interests in twelve programs. Mr. King owns $310,000 of interests in three programs. Mr. Millar owns $260,000 of interests in three programs. Mr. Quinlan owns $2,100,000 of interests in five programs, including a 16.67% interest one program. Mr. Thompson owns $25,000 of interests in one program. Other than Mr. Quinlan's interest in one drilling program, no officer or director owns greater than a 10% interest in any particular drilling program.

Gregory S. Johnson, who had been the Executive Vice President of Warren E & P and was a Senior Vice President—Oil and Gas Operations for Warren, died in June 2002. Effective as of August 1, 2002, we entered into a Stock Redemption and Purchase Agreement with the Estate of Gregory S. Johnson to acquire 702,500 shares of our common stock owned by the estate for the price of $2.71 per share. The purchase price is payable over ten years in equal monthly installments of $13,333.34 ($160,000 per annum). Gregory S. Johnson originally obtained his common shares when we acquired Warren E & P of which he was a 50% shareholder in September 2000. The shares being acquired are subject to a collateral escrow agreement wherein 70,250 shares will be returned to us on each anniversary date until the purchase price is paid in full on July 31, 2012. Additionally, as part of the transaction stock options held by Mr. Johnson to acquire 400,000 shares of our common stock for a price of $4.00 per share were terminated and cancelled.

PART IV

Item 14. Controls and Procedures

Warren's Chief Executive Officer and Chief Financial Officer (Certifying Officers) performed an evaluation of the Company's disclosure controls and procedures within 90 days prior to the filing of this Form 10-K. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by an issuer in the reports that it files or submits under the Exchange Act is accumulated and communicated to the issuer's management, including its Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures.

Based on this evaluation, the Certifying Officers have concluded that the Company's disclosure controls and procedures are effective. In addition, there have been no significant changes in the internal controls or in other factors that could significantly affect these controls subsequent to the date of their evaluation.

Item 15: Exhibits, Financial Statement Schedules and Reports on Form 8-K

(a)(1) Financial Statements

(a)(2) All other schedules have been omitted because the required information is inapplicable or is shown in the Notes to the Consolidated Financial Statements.

(a)(3) Exhibits required to be filed by Item 601 of Regulation S-K.

Exhibit No.	Description
2.1*	Stock Exchange Agreement, dated September 1, 2000, by and among the Registrant, Petroleum Development Corporation, James C. Johnson, Jr. and Gregory S. Johnson.
3.1*	Certificate of Incorporation of Registrant dated June 11, 1990
3.2*	Amendment to Certificate of Incorporation of Registrant dated November 15, 1990
3.3*	Amendment to Certificate of Incorporation of Registrant dated November 4, 1992
3.4*	Amendment to Certificate of Incorporation of Registrant dated September 3, 1996
3.5*	Bylaws of the Registrant, dated June 12, 1990
4.1*	Form of Stock Certificate for Common Stock
4.2*	Indenture between the Registrant and Continental Stock Transfer and Trust Company, as Trustee, dated December 1, 2000 regarding 12% debentures due December 31, 2007
4.3*	Form of Bond Certificate for 12% debentures due December 31, 2007
4.4*	Indenture between the Registrant and Continental Stock Transfer and Trust Company, as Trustee, dated February 1, 1999 regarding 13.02% debentures due December 31, 2010 and December 31, 2015
4.5*	Form of Bond Certificate for 13.02% debentures due December 31, 2010
4.6*	Form of Bond Certificate for 13.02% debentures due December 31, 2015
4.7*	Form of Class A Warrant
4.8*	Form of Class B Warrant
4.9*	Form of Class C Warrant
4.10*	Form of Class D Warrant
10.1*	2000 Equity Incentive Plan for Warren E & P Subsidiary
10.2*	Amendment to 2000 Stock Incentive Plan for Warren E & P Subsidiary
10.3*	2001 Stock Incentive Plan
10.4*	2001 Key Employee Stock Incentive Plan
10.5*	Employment Agreement dated January 1, 2001, between the Registrant and Norman F. Swanton
10.6*	Employment Agreement dated January 1, 2001, between the Registrant and Timothy A. Larkin
10.7*	Employment Agreement dated September 14, 2000, between the Registrant and James C. Johnson, Jr.

Exhibit No.	Description
10.8*	Employment Agreement dated September 14, 2000, between the Registrant and Gregory S. Johnson
10.9*	Employment Agreement dated May 7, 2001, between the Registrant and Jack B. King
10.10*	Employment Agreement dated June 25, 2001, between the Registrant and David E. Fleming
10.11*	Form of Indemnification Agreement
10.12*	Joint Venture Agreement dated May 24, 1999, by and between Warren Resources of California, Inc., Warren Development Corp., Warren E & P and Magness Petroleum Company
10.13**	Crude Oil Sale and Purchase Contract dated November 7, 1996, between Huntway Refining Company and Magness Petroleum Company
10.14*	May 11, 2000 Agreement to Amend the Price and Term Clauses of the Crude Oil Sale and Purchase Contract dated November 7, 1996, between Huntway Refining Company and Magness Petroleum Company
10.15*	Gas Purchase Agreement dated January 28, 2000, by and between Western Gas Resources, Inc. and Big Basin Petroleum, LLC
10.16*	December 20, 2000 Letter of Agreement to Amend the Gas Purchase Contract dated January 28, 2000, between Western Gas Resources Inc. and Petroleum Development Corp., as successor in interest to Big Basin Petroleum, LLC
10.17*	Gas Purchase and Sales Contract dated April 1, 2000, between the Registrant and Tenaska Marketing Ventures
10.18*	Form of Partnership Production Marketing Agreement
11†	Statements regarding Computation of Per Share Earnings (Included in Part 4)
14†	Code of Ethics for Senior Financial Officers
21.1*	Subsidiaries of the Registrant
23.2†	Consent of Williamson Petroleum Consultants, Inc.
99.1†	Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act

* Incorporated by reference to the Company's Registration Statement on Form 10, Commission File No. 000-33275, filed on October 26, 2001.

** Incorporated by reference to the Company's Amendment No. 1 to Registration Statement on Form 10/A, Commission File No. 000-33275, filed on March 6, 2002.

† Filed herewith.

(b) Reports on Form 8-K

A report on Form 8-K dated December 17, 2002 was filed in which the earliest event reported was December 12, 2002 reflecting that the company had completed an initial closing of its 8% cumulative convertible preferred stock. This event was reported under Item 5 "Other Events". The following were filed under Item 7 "Exhibits": Certificate of Designation for Warren's 8% Cumulative Convertible Preferred Stock, and the Registration Rights Agreement executed by Warren and delivered to the holders of the preferred stock.

A report on Form 8-K dated December 24, 2002 was filed in which the earliest event reported was December 13, 2002 reflecting that the company had completed the transactions with Anadarko Petroleum Corporation ("Anadarko"). This event was reported under Item 2 "Acquisition or Disposition of Assets". The following were filed under Item 7 "Exhibits": the Exchange Agreement between Warren and Anadarko, the Joint Exploration Agreement between Warren and Anadarko and the Unit Operating Agreement between Warren and Anadarko.

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.

WARREN RESOURCES, INC.

By	/s/ NORMAN F. SWANTON Norman F. Swanton	President, Chief Executive Officer, Director and Chairman
By	/s/ TIMOTHY A. LARKIN Timothy A. Larkin	Senior Vice President, Chief Financial Officer, and Principal Accounting Officer

Dated: March 28, 2003

Pursuant to the requirements of the Securities and 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.

Signature	Title (Principal Function)	Date
/s/ NORMAN F. SWANTON Norman F. Swanton	President, Chief Executive Officer, Director and Chairman	March 28, 2003
/s/ TIMOTHY A. LARKIN Timothy A. Larkin	Senior Vice President, Chief Financial Officer and Principal Accounting Officer	March 28, 2003
/s/ ANTHONY COELHO Anthony Coelho	Director	March 28, 2003
/s/ LLOYD DAVIES Lloyd Davies	Director	March 28, 2003
/s/ DOMINICK D'ALLEVA Dominick D'Alleva	Director	March 28, 2003
/s/ MARSHALL MILLER Marshall Miller	Director	March 28, 2003
/s/ THOMAS NOONAN Thomas Noonan	Director	March 28, 2003
/s/ MICHAEL R. QUINLAN Michael R. Quinlan	Director	March 28, 2003

CERTIFICATIONS

I, Norman F. Swanton, certify that:

1. I have reviewed this annual report on Form 10-K of Warren Resources, Inc.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

   (a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   (b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   (c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date.;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   (a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 28, 2003

/s/ NORMAN F. SWANTON

Norman F. Swanton,
Chairman and Chief Executive Officer

CERTIFICATIONS

I, Timothy A. Larkin, certify that:

1. I have reviewed this annual report on Form 10-K of Warren Resources, Inc.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

   (a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   (b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   (c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   (a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

March 28, 2003

/s/ TIMOTHY A. LARKIN

Timothy A. Larkin,
Senior Vice President and Chief
Financial Officer

INDEX TO EXHIBITS

Exhibit No.	Description
2.1*	Stock Exchange Agreement, dated September 1, 2000, by and among the Registrant, Petroleum Development Corporation, James C. Johnson, Jr. and Gregory S. Johnson.
3.1*	Certificate of Incorporation of Registrant dated June 11, 1990
3.2*	Amendment to Certificate of Incorporation of Registrant dated November 15, 1990
3.3*	Amendment to Certificate of Incorporation of Registrant dated November 4, 1992
3.4*	Amendment to Certificate of Incorporation of Registrant dated September 3, 1996
3.5*	Bylaws of the Registrant, dated June 12, 1990
4.1*	Form of Stock Certificate for Common Stock
4.2*	Indenture between the Registrant and Continental Stock Transfer and Trust Company, as Trustee, dated December 1, 2000 regarding 12% debentures due December 31, 2007
4.3*	Form of Bond Certificate for 12% debentures due December 31, 2007
4.4*	Indenture between the Registrant and Continental Stock Transfer and Trust Company, as Trustee, dated February 1, 1999 regarding 13.02% debentures due December 31, 2010 and December 31, 2015
4.5*	Form of Bond Certificate for 13.02% debentures due December 31, 2010
4.6*	Form of Bond Certificate for 13.02% debentures due December 31, 2015
4.7*	Form of Class A Warrant
4.8*	Form of Class B Warrant
4.9*	Form of Class C Warrant
4.10*	Form of Class D Warrant
10.1*	2000 Equity Incentive Plan for Warren E & P Subsidiary
10.2*	Amendment to 2000 Stock Incentive Plan for Warren E & P Subsidiary
10.3*	2001 Stock Incentive Plan
10.4*	2001 Key Employee Stock Incentive Plan
10.5*	Employment Agreement dated January 1, 2001, between the Registrant and Norman F. Swanton
10.6*	Employment Agreement dated January 1, 2001, between the Registrant and Timothy A. Larkin
10.7*	Employment Agreement dated September 14, 2000, between the Registrant and James C. Johnson, Jr.
10.8*	Employment Agreement dated September 14, 2000, between the Registrant and Gregory S. Johnson
10.9*	Employment Agreement dated May 7, 2001, between the Registrant and Jack B. King
10.10*	Employment Agreement dated June 25, 2001, between the Registrant and David E. Fleming
10.11*	Form of Indemnification Agreement
10.12*	Joint Venture Agreement dated May 24, 1999, by and between Warren Resources of California, Inc., Warren Development Corp., Warren E & P and Magness Petroleum Company
10.13**	Crude Oil Sale and Purchase Contract dated November 7, 1996, between Huntway Refining Company and Magness Petroleum Company
10.14*	May 11, 2000 Agreement to Amend the Price and Term Clauses of the Crude Oil Sale and Purchase Contract dated November 7, 1996, between Huntway Refining Company and Magness Petroleum Company
10.15*	Gas Purchase Agreement dated January 28, 2000, by and between Western Gas Resources, Inc. and Big Basin Petroleum, LLC

Exhibit No.	Description
10.16*	December 20, 2000 Letter of Agreement to Amend the Gas Purchase Contract dated January 28, 2000, between Western Gas Resources Inc. and Petroleum Development Corp., as successor in interest to Big Basin Petroleum, LLC
10.17*	Gas Purchase and Sales Contract dated April 1, 2000, between the Registrant and Tenaska Marketing Ventures
10.18*	Form of Partnership Production Marketing Agreement
11†	Statements regarding Computation of Per Share Earnings (Included in Part 4)
14†	Code of Ethics for Senior Financial Officers
21.1*	Subsidiaries of the Registrant
23.1†	Consent of Williamson Petroleum Consultants, Inc.
99.1†	Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act

* Incorporated by reference to the Company's Registration Statement on Form 10, Commission File No. 000-33275, filed on October 26, 2001.

** Incorporated by reference to the Company's Amendment No. 1 to Registration Statement on Form 10/A, Commission File No. 000-33275, filed on March 6, 2002.

† Filed herewith.

INDEX TO FINANCIAL STATEMENTS

Report of Independent Certified Public Accountants

Board of Directors
Warren Resources, Inc.

We have audited the accompanying consolidated balance sheets of Warren Resources, Inc. and Subsidiaries as of December 31, 2002 and 2001, and the related consolidated statements of operations, stockholders' equity (deficit) and cash flows for each of the three years in the period ended December 31, 2002. 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 auditing standards generally accepted in the United States of America. 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 Warren Resources, Inc. and Subsidiaries as of December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note A to the consolidated financial statements, effective January 1, 2001 the Company changed its method of accounting for derivative instruments and hedging activities and, effective January 1, 2002, adopted Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets*.

GRANT THORNTON LLP

Oklahoma City, Oklahoma
March 6, 2003

Warren Resources, Inc. and Subsidiaries
CONSOLIDATED BALANCE SHEETS
December 31,

	2002	2001
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 23,184,936	$22,923,605
Accounts receivable—trade	6,895,483	5,543,326
Accounts receivable from affiliated partnerships	921,252	801,661
Trading securities	78,383	205,989
Restricted investments in U.S. Treasury bonds—available for sale, at fair value (amortized cost of $683,513 in 2002 and $1,142,637 in 2001)	810,822	1,187,123
Other current assets	2,053,248	1,294,986
Assets held for sale	—	3,757,900
Total current assets	33,944,124	35,714,590
OTHER ASSETS		
Oil and gas properties—at cost, based on successful efforts method of accounting, net of accumulated depletion and amortization	48,684,362	39,974,798
Property and equipment—at cost, net	751,479	891,304
Restricted investments in U.S. Treasury bonds—available for sale, at fair value (amortized cost of $7,571,860 in 2002 and $7,399,989 in 2001)	9,058,851	7,791,555
Deferred bond offering costs, net of accumulated amortization of $3,051,046 in 2002 and $2,535,160 in 2001	3,390,022	3,905,908
Goodwill	3,430,246	3,430,246
Other assets	5,365,435	3,191,813
Restricted cash	3,637,775	—
	74,318,170	59,185,624
	$108,262,294	$94,900,214
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)		
CURRENT LIABILITIES		
Current maturities of debentures	$ 5,466,970	$ 4,747,370
Current maturities of other long-term liabilities	178,980	392,721
Accounts payable and accrued expenses	3,822,809	6,511,137
Deferred income—turnkey drilling contracts with affiliated partnerships	32,265,725	32,943,586
Total current liabilities	41,734,484	44,594,814
LONG-TERM LIABILITIES		
Debentures, less current portion	49,202,730	53,391,330
Other long-term liabilities, less current portion	1,353,129	29,191
Contingent repurchase obligation	—	3,318,993
	50,555,859	56,739,514
MINORITY INTEREST	8,970,078	—
STOCKHOLDERS' EQUITY (DEFICIT)		
8% convertible preferred stock, par value $.00001; authorized 20,000,000 shares, issued and outstanding, 1,784,197 shares in 2002 (aggregate liquidation preference $21,410,364 in 2002)	20,955,838	—
Common stock—$.0001 and $.001 par value at December 31, 2002 and 2001; authorized, 100,000,000 shares; issued, 17,581,996 shares in 2002 and 17,537,579 shares in 2001	1,758	17,538
Additional paid-in capital	52,424,147	52,197,669
Accumulated deficit	(66,529,795)	(58,903,571)
Accumulated other comprehensive income, net of applicable income taxes of $646,000 in 2002 and $171,792 in 2001	971,508	264,260
	7,823,456	(6,424,104)
Less common stock in Treasury—at cost; 707,691 shares in 2002 and 4,563 shares in 2001	821,583	10,010
	7,001,873	(6,434,114)
	$108,262,294	$94,900,214

Warren Resources, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF OPERATIONS
Year ended December 31,

	2002	2001	2000
REVENUES			
Turnkey contracts with affiliated partnerships	$ 5,841,110	$ 30,102,946	$33,984,960
Oil and gas sales from marketing activities	11,272,398	14,866,954	15,420,917
Well services, 79% and 12% with affiliated partnerships in 2002 and 2001	1,895,453	5,574,335	4,297,414
Oil and gas sales	592,528	948,270	200,330
Net gain (loss) on investments	464,185	(10,337)	587,349
Interest and other income	5,257,842	1,977,082	2,457,146
Gain on sale of oil and gas properties	4,286,774	—	—
	29,610,290	53,459,250	56,948,116
EXPENSES			
Turnkey contracts	4,965,426	25,953,340	22,783,248
Cost of marketed oil and gas purchased from affiliated partnerships	11,121,522	15,298,842	15,800,258
Well services	838,878	3,519,085	3,167,550
Production and exploration	1,325,764	567,756	355,347
Depreciation, depletion and amortization	9,930,162	14,462,119	3,065,460
General and administrative	6,277,792	5,484,773	6,416,043
Interest	6,312,631	5,776,234	6,967,850
Contingent repurchase obligation	(3,064,661)	3,318,993	—
	37,707,514	74,381,142	58,555,756
Loss before provision for income taxes	(8,097,224)	(20,921,892)	(1,607,640)
DEFERRED INCOME TAX EXPENSE (BENEFIT)	(471,000)	151,700	(412,000)
NET LOSS	(7,626,224)	(21,073,592)	(1,195,640)
LESS DIVIDENDS ON PREFERRED SHARES	16,206	—	—
NET LOSS APPLICABLE TO COMMON STOCKHOLDERS	$ (7,642,430)	$(21,073,592)	$ (1,195,640)
BASIC AND DILUTED LOSS PER COMMON SHARE	$ (0.44)	$ (1.20)	$ (0.10)
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING	17,339,869	17,532,882	12,461,814

Warren Resources, Inc. and Subsidiaries
CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY (DEFICIT)
Years ended December 31, 2002, 2001 and 2000

	Preferred stock		Common stock		Additional paid-in capital	Accumulated deficit	Accumulated other comprehensive income (loss)	Treasury stock	Total stockholders' equity (deficit)
	Shares	Amount	Shares	Amount					
Balance at January 1, 2000	—	$ —	11,454,938	$11,455	$22,208,968	$(36,634,339)	$ (204,458)	$ —	$(14,618,374)
Issuance of common stock	—	—	33,343	33	100,374	—	—	—	100,407
Repurchase of common stock	—	—	(35,250)	(35)	(106,965)	—	—	—	(107,000)
Shares issued from exercise of Class B warrants	—	—	909,178	909	1,652,080	—	—	—	1,652,989
Shares issued from exercise of Class C warrants	—	—	1,020,689	1,021	3,320,606	—	—	—	3,321,627
Shares issued from exercise of Class D warrants	—	—	1,178,709	1,179	8,858,961	—	—	—	8,860,140
Conversion to common stock from convertible debentures	—	—	1,366,654	1,366	9,455,359	—	—	—	9,456,725
Acquisition of Petroleum Development Corporation ("Pedco")	—	—	1,600,000	1,600	6,398,400	—	—	—	6,400,000
Extension of expiration period for Class B warrants	—	—	—	—	139,399	—	—	—	139,399
Issuance of warrants	—	—	—	—	160,497	—	—	—	160,497
Comprehensive loss									
Net loss	—	—	—	—	—	(1,195,640)	—	—	(1,195,640)
Other comprehensive income									
Net change in unrealized gain on investment securities available for sale, net of applicable income taxes	—	—	—	—	—	—	704,818	—	704,818
Total comprehensive loss									(490,822)
Balance at December 31, 2000	—	—	17,528,261	17,528	52,187,679	(37,829,979)	500,360	—	14,875,588
Conversion to common stock from convertible debentures	—	—	9,318	10	9,990	—	—	—	10,000
Purchase of Treasury stock	—	—	—	—	—	—	—	(10,010)	(10,010)
Comprehensive loss									
Net loss	—	—	—	—	—	(21,073,592)	—	—	(21,073,592)
Other comprehensive loss									
Cumulative effect of change in accounting principle	—	—	—	—	—	—	(1,449,930)	—	(1,449,930)
Reclassification adjustment for derivative losses	—	—	—	—	—	—	1,449,930	—	1,449,930
Net change in unrealized gain on investment securities available for sale, net of applicable income taxes	—	—	—	—	—	—	(236,100)	—	(236,100)
Total comprehensive loss									(21,309,692)
Balance at December 31, 2001	—	—	17,537,579	17,538	52,197,669	(58,903,571)	264,260	(10,010)	(6,434,114)

Warren Resources, Inc. and Subsidiaries
CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY (DEFICIT)—CONTINUED
Years ended December 31, 2002, 2001 and 2000

	Preferred stock		Common stock		Additional paid-in capital	Accumulated deficit	Accumulated other comprehensive income (loss)	Treasury stock	Total stockholders' equity (deficit)
	Shares	Amount	Shares	Amount					
Balance at December 31, 2001	—	—	17,537,579	17,538	52,197,669	(58,903,571)	264,260	(10,010)	(6,434,114)
Change in par value of common stock	—	—	—	(15,784)	15,784	—	—	—	—
Dividends declared on preferred stock	—	—	—	—	(16,206)	—	—	—	(16,206)
Shares issued for services	—	—	23,695	2	86,902	—	—	—	86,904
Conversion to common stock from convertible debt	—	—	20,722	2	139,998	—	—	—	140,000
Issuance of preferred stock, net of offering costs of $454,740	1,784,197	20,955,838	—	—	—	—	—	—	20,955,838
Purchase of Treasury stock	—	—	—	—	—	—	—	(811,573)	(811,573)
Comprehensive loss									
Net loss	—	—		—	—	(7,626,224)	—	—	(7,626,224)
Other comprehensive loss									
Net change in unrealized gain on investment securities available for sale, net of applicable income taxes	—	—	—	—	—	—	707,248	—	707,248
Total comprehensive loss									(6,918,976)
Balance at December 31, 2002	1,784,197	$20,955,838	17,581,996	$ 1,758	$52,424,147	$(66,529,795)	$971,508	$(821,583)	$ 7,001,873

The accompanying notes are an integral part of this statement.

Warren Resources, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF CASH FLOWS
Year ended December 31,

	2002	2001	2000
Cash flows from operating activities			
Net loss	$(7,626,224)	$(21,073,592)	$(1,195,640)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities			
Accretion of discount on available-for-sale debt securities	(514,818)	(473,080)	(502,017)
Amortization and write-off of deferred bond offering costs	515,886	442,130	380,365
Gain on sale of U.S. Treasury bonds—available for sale	(28,104)	(21,019)	(541,722)
Depreciation, depletion and amortization	9,930,162	14,462,119	3,065,460
Gain on sale of oil and gas properties	(4,286,774)	—	—
Expense on issuance of warrants	—	—	299,896
Common stock issued for services	86,904	—	172,444
Non-cash compensation	200,000	—	—
Deferred tax expense (benefit)	(471,000)	151,700	(412,000)
Change in assets and liabilities			
Decrease in trading securities	127,606	235,527	2,642,565
(Increase) decrease in accounts receivable—trade	(902,157)	275,723	(3,564,306)
Increase in accounts receivable from affiliated partnerships	(119,591)	(21,740)	(358,724)
(Increase) decrease in other assets	2,886,299	862,956	(961,253)
Increase (decrease) in accounts payable and accrued expenses	(2,704,532)	(1,251,636)	1,151,061
Increase (decrease) in deferred income from affiliated partnerships	(677,861)	(12,619,695)	10,482,609
Increase (decrease) in contingent repurchase obligation to affiliated partnerships	(3,064,661)	3,318,993	—
Increase in other long-term liabilities	548,200	—	—
Net cash provided by (used in) operating activities	(6,100,665)	(15,711,614)	10,658,738
Cash flows from investing activities			
Purchases of U.S. Treasury bonds—available for sale	(14,906)	(1,264,058)	(4,584,677)
Purchases of oil and gas properties	(4,699,453)	(16,944,421)	(20,957,501)
Purchases of property and equipment	(50,592)	(189,666)	(28,227)
Proceeds from the sale of oil and gas properties, net of selling fees	12,874,512	—	—
Cash acquired from Pedco on acquisition	—	—	629,896
Proceeds from U.S. Treasury bonds—available for sale	845,081	763,353	5,928,078
Increase in restricted cash	(3,637,775)	—	—
Net cash provided by (used in) investing activities	5,316,867	(17,634,792)	(19,012,431)
Cash flows from financing activities			
Proceeds from issuance of long-term debt	—	—	15,390,000
Payments on long-term debt	(2,813,965)	(1,876,645)	(999,301)
Proceeds from issuance of common stock	—	—	13,762,717
Deferred bond offering costs	—	—	(1,345,270)
Deferred offering costs	—	(812,886)	—
Issuance of preferred stock, net	3,861,718	—	—
Purchase of treasury stock	(2,624)	(10,010)	(107,000)
Net cash provided by (used in) financing activities	1,045,129	(2,699,541)	26,701,146
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	261,331	(36,045,947)	18,347,453
Cash and cash equivalents at beginning of year	22,923,605	58,969,552	40,622,099
Cash and cash equivalents at end of year	$23,184,936	$22,923,605	$58,969,552

Warren Resources, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF CASH FLOWS—CONTINUED
Year ended December 31,

	2002	2001	2000
Supplemental disclosure of cash flow information			
Cash paid for interest, net of amount capitalized	$ 5,770,006	$5,275,100	$ 6,386,551
Noncash investing and financing activities			
Conversion to common stock from convertible debt	140,000	10,000	9,456,725
Exchange of 2007 Sinking Fund Bond for preferred stock	978,600	—	—
Accounts receivable consisting of service credits relating to the sale of Pinnacle	450,000	—	—
Other assets consisting of deferred payments relating to the conveyance of oil and gas property	5,818,183	—	—
Purchase of treasury stock of $808,949 and incurrence of noncash compensation of $200,000 through the issuance of a non-interest bearing note (note D)	1,008,949	—	—
Accrued preferred stock dividend	16,206	—	—
During 2002, the Company acquired affiliated L.L.C. interests in exchange for 1,342,960 shares of preferred stock (note J). In conjunction with the acquisition, assets were acquired and liabilities were assumed as follows:			
Estimated fair value of assets acquired	$25,256,708		
Liabilities assumed	9,141,188		
Estimated fair value of preferred stock	$16,115,520		
During 2000, the Company acquired Pedco in exchange for 1,600,000 shares of common stock (note J). In conjunction with the acquisition, assets were acquired and liabilities were assumed as follows:			
Estimated fair value of assets acquired, including cash and cash equivalents of $629,896			$ 7,710,418
Liabilities assumed			(1,310,418)
Estimated fair value of common stock			$ 6,400,000

The accompanying notes are an integral part of this statement.

Warren Resources, Inc. and Subsidiaries
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2002, 2001 and 2000

NOTE A—ORGANIZATION AND ACCOUNTING POLICIES

Nature of Operations

Warren Resources, Inc. (the "Company"), was formed as a New York corporation on June 12, 1990 for the purpose of acquiring and developing oil and gas properties. On September 5, 2002, the Company changed its State of Incorporation to Delaware. As a result, all shares of the Company's stock were converted into shares of the Delaware corporation and the par value of stock was changed from $0.001 to $0.0001 per share. Primarily, the Company's properties are located in New Mexico, Texas, Wyoming, North Dakota, Michigan and California. In addition, the Company serves as the managing general partner (the "MGP") to affiliated partnerships and joint ventures. Also, the Company, through its wholly owned subsidiaries, provides turnkey contract drilling services to affiliated partnerships and joint ventures, well services including engineering, maintenance, operations and, commencing in 2000, gas marketing and transportation services.

Management Plans

The Company has incurred a net loss of approximately $7,600,000 during 2002. At December 31, 2002, current liabilities exceeded current assets by approximately $7,800,000. The Company had equity of approximately $7,000,000 at December 31, 2002.

The 2002 net loss includes approximately $13.6 million of noncash charges including oil and gas properties impairments and a reversal of previously recognized deferred revenue relating to wells conveyed to Anadarko Petroleum Corporation in the exchange agreement and joint exploration agreement entered into on December 13, 2002. Wells that had been previously allocated to drilling programs were conveyed to Anadarko. As a result, turnkey revenue which had been recognized on those wells was reversed.

In order to improve operations and liquidity and meet its cash flow needs, the Company has or intends to do the following:

- Raise additional capital through the sale of preferred stock.
- Obtain a credit facility based in part on the value of our proven reserves.
- Continue to privately place drilling programs, which based on prior experience, management anticipates raising approximately $10 million in 2003.
- Generate cash through a divesture program to dispose of substantially all wells and leases that do not meet the Company's strategic focus within the Rocky Mountains and California.
- Generate turnkey profit and operating cash flow from turnkey drilling contracts equal to approximately 25% of the total amount of total turnkey price.
- Reduce fixed overhead expenses and primarily conduct developmental drilling operations in the Company's two main target areas, coal bed methane properties in Wyoming and oil formations in the Wilmington field in California.

As a result of these plans, management believes that it will generate sufficient cash flows to meet its current obligations in 2003.

Principles of Consolidation

The consolidated financial statements include the accounts of the Company, its wholly owned subsidiaries, Warren Development Corp., Warren Drilling Corp., Warren Management Corp., Petroleum Development Corporation ("Pedco"), CJS Pinnacle Petroleum Services, LLC ("Pinnacle") which was sold on February 14, 2002 and certain partnerships where the Company has majority control (note J). All significant intercompany accounts and transactions have been eliminated in consolidation.

The Company conducts the majority of its oil and gas operations through joint ventures and partnerships. The Company enters into joint venture agreements with limited partnerships whereby the Company assigns a 75% (before payout) working interest in an oil and gas lease to a limited partnership while retaining a 25% (before payout) working interest. This ownership interest is an undivided interest in the mineral rights and each owner is responsible for its designated well expenditures. In exchange for the 75% working interest, the limited partners pay intangible drilling costs and, if a well is successful, the Company pays completion costs, including lease and well equipment. The Company has a 25% interest in the joint venture before payout and receives an additional reversionary 15% interest once payout occurs. The Company also has a 10% interest in the partnership revenue and expenses which increases to 25% once payout occurs. Payout is achieved once the limited partners in a particular program receive distributions equal to 100% of their original investment. Distributions received by the participants are determined by the revenues generated from the wells in each of the various programs less any applicable lease operating expenses. Therefore, once payout is achieved, the Company has a total interest of 55% in the net revenue generated from all wells assigned to a particular program. The Company has subordinated substantially all its general partner and joint venture rights to production for 1998 and earlier partnerships until payout and its general partner's interest in 1999 and later partnerships until payout. The Company proportionately consolidates its share of the costs incurred on undivided working interest of affiliated partnerships and joint ventures in which the Company does not have majority control. The Company primarily incurs lease acquisition costs and completion costs, including lease and well equipment, on wells developed in these partnerships and joint ventures. All significant intercompany accounts and transactions have been eliminated.

Oil and Gas Properties

The Company uses the successful efforts method of accounting for oil and gas properties. Under this methodology, costs incurred to acquire mineral interests in oil and gas properties, to drill and equip exploratory wells that find proved reserves and to drill and equip development wells are capitalized. Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs and costs of carrying and retaining unproved properties are expensed.

Unproved oil and gas properties that are individually significant are periodically assessed for impairment of value and a loss is recognized at the time of impairment by providing an impairment allowance. Other unproved properties are amortized based on the Company's experience of successful drilling and historical lease expirations.

Capitalized costs of producing oil and gas properties are depleted by the units-of-production method on a field-by-field basis. Lease costs are depleted using total proved reserves while lease equipment and intangible development costs are depleted using proved developed reserves. The Company's proved properties are evaluated on a field-by-field basis for impairment. An impairment loss is indicated whenever net capitalized costs exceed expected future net cash flow based on engineering estimates. In this circumstance, the Company recognizes an impairment loss for the amount by which the carrying value of the properties exceeds the estimated fair value (based on discounted cash flow).

On the sale or retirement of a complete unit of a proved property, the cost and related accumulated depletion and amortization are eliminated from the property accounts, and the resultant gain or loss is recognized. On the retirement or sale of a partial unit of proved property, the cost is charged to accumulated depletion and amortization with a resulting gain or loss recognized in earnings.

On the sale of an entire interest in an unproved property, a gain or loss on the sale is recognized, taking into consideration the amount of any recorded impairment if the property had been assessed individually. If a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained.

Investment in CJS Pinnacle Petroleum Services, LLC

Pinnacle, a drilling services company, was formed in 1997 and at that time the Company obtained a 25% interest through its initial capital contribution of $500 and a 9% loan to Pinnacle of $1,800,000. The Company accounted for its 25% investment using the equity method. On January 1, 1999, the Company acquired an additional 50% interest in Pinnacle by the assumption of liabilities of approximately $2,267,000. Effective September 1, 2000, with the acquisition of Pedco, Pinnacle became a 100% owned subsidiary (Note L). On February 14, 2002, the Company completed the sale of substantially all of the assets of Pinnacle (Note C).

Revenue Recognition

The Company enters into agreements with affiliated partnerships to drill wells to completion for a fixed price. The Company, in turn, enters into drilling contracts primarily with unrelated parties to drill wells on a day work basis. Therefore, if problems are encountered on a well, the cost of that well will increase and gross profit will decrease and could result in a loss on the well. The Company recognizes revenue from the turnkey drilling agreements on the percentage-of-completion method based on total costs incurred to total estimated costs to complete. When estimates of revenues and expenses indicate a loss, the total estimated loss is accrued. Oil and gas sales result from undivided interests held by the Company in various oil and gas properties. Sales of natural gas and oil produced are recognized when delivered to or picked up by the purchaser. Oil and gas sales from marketing activities result from sales by the Company of oil and gas produced by affiliated joint ventures and partnerships and are recognized when delivered to purchasers.

Cash and Cash Equivalents

The Company considers all highly liquid investments with maturities of three months or less when acquired to be cash equivalents. The Company maintains its cash and cash equivalents in bank deposit accounts which exceed federally insured limits. At December 31, 2002, the Company had approximately 97% of its cash and cash equivalents with one financial institution. The Company has not experienced any losses in such accounts and believes it is not exposed to any significant credit risk on cash and cash equivalents.

Accounts Receivable

Accounts receivable include amounts due from affiliated partnerships and joint ventures for advances and expenditures made by the Company on behalf of such entities, as well as trade receivables. Credit is extended based on evaluation of a customer's financial condition and, generally, collateral is not required. Accounts receivable are due within 30 days and are stated at amounts due from customers net of an allowance for doubtful accounts when the Company believes collection is doubtful. Accounts outstanding longer than the contractual payment terms are considered past due. The Company determines its allowance by considering a number of factors, including the length of time trade accounts receivable are past due, the Company's previous loss history, the customer's current ability to pay its obligation to the Company, and the condition of the general economy and the industry as a whole. The Company writes off specific accounts receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for doubtful accounts.

The Company grants credit to purchasers of oil and gas and owners of managed properties, substantially all of whom are located in California, Wyoming, New Mexico and Texas.

Investments

The Company classifies its debt and equity securities into two categories: trading securities and available-for-sale securities. Trading securities, classified as current assets, are recorded at fair value with net unrealized gains or losses included in the determination of net earnings. Available-for-sale securities are measured at fair value, with net unrealized gains and losses excluded from net earnings and reported as other comprehensive income (loss). Realized gains and losses are determined on the basis of specific identification of the securities.

Deferred Bond Offering Costs

Costs incurred in connection with the issuance of long-term debt are capitalized and amortized over the term of the related debt using the effective interest rate method.

Contingent Repurchase Obligation

A contingent repurchase obligation exists when the present value of the Company's potential future obligation to affiliated partnerships under repurchase agreements (Note G) is greater than their estimated future net revenues from its oil and gas properties, as determined by independent petroleum engineers.

Income Taxes

Deferred income taxes are recognized for the tax consequences in future years of differences between the tax basis of assets and liabilities and their financial reporting amounts based on enacted tax laws and statutory rates applicable to the period in which the differences are expected to affect taxable income. Valuation allowances are established when, in management's opinion, it is more likely than not that a portion or all of the deferred tax assets will not be realized.

Use of Estimates

In preparing financial statements, accounting principles generally accepted in the United States of America require management to make estimates and assumptions in determining 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.

Gas Imbalances

The Company follows the sales method of accounting for gas imbalances. A liability is recorded when the Company's excess takes of natural gas volumes exceed its estimated remaining recoverable reserves. No receivables are recorded for those wells where the Company has taken less than its ownership share of gas production. The Company has no significant gas imbalances.

Capitalized Interest

Interest of approximately $1,400,000, $2,300,000 and $1,300,000 was capitalized during the years ended December 31, 2002, 2001 and 2000, respectively, relating to a major coalbed methane development project that was not being currently depreciated, depleted or amortized and on which exploration activities were in progress during 2002, 2001 and 2000. Approximately $1,933,000 of interest previously capitalized was charged against the proceeds of the conveyance of certain of these unproved properties (Note C).

Hedging Activities

During the year ended December 31, 2000, the Company entered into gas price swaps to manage its exposure to gas price volatility for marketed gas. The hedging instruments are usually placed with counterparties that the Company believes are minimal credit risks. The gas reference prices upon which the price hedging instruments are based reflect various market indices that have a high degree of historical correlation with actual prices received by the Company.

The Company accounted for its hedging instruments using the deferral method of accounting through December 31, 2000. Under this method, realized gains and losses from the Company's price risk management activities are recognized in gas revenues when the associated sale occurs and the resulting cash flows are reported as cash flows from operating activities. Gains and losses on hedging contracts that are closed before the hedged production occurs are deferred until the production month originally hedged. In the event of a loss of correlation between changes in oil and gas reference prices under a hedging instrument and actual oil and gas prices, a gain or loss is recognized currently to the extent the hedging instrument has not offset changes in actual oil and gas prices. For the years ended December 31, 2001 and 2000, the Company hedged approximately 3,000 dekatherms of natural gas per day for the months April 2000 through March 2001 based on the Inside FERC Index price and fixed floor and ceiling prices of $2.50 and $3.55, respectively. For the years ended December 31, 2001 and 2000, the Company incurred losses on its hedging contracts of approximately $509,000 and $1,600,000, respectively, which are reflected as a reduction of gas sales from marketing activities.

The Company adopted the provisions under Statement of Financial Accounting Standards ("SFAS") No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended, in the first quarter of its year ended December 31, 2001. In accordance with the transition provisions of SFAS No. 133, the Company recorded a net-of-tax-cumulative-effect-type adjustment of approximately $1,450,000 in accumulated other comprehensive loss to recognize at fair value all derivatives that are designated as cash flow hedging financial instruments. The Company's hedging agreements expired in March 2001.

Accounting For Long-Lived Assets

The Company reviews property and equipment for impairment whenever indicators of impairment are present to determine if the carrying amounts exceed the estimated future net cash flows to be realized. Impairment losses are recognized based on the estimated fair value of the asset.

Stock Based Compensation

At December 31, 2002, the Company had a stock-based employee plan, which is described more fully in Note E to the financial statements. The Company accounts for stock based employee awards using the intrinsic value method for its employee option plans in which compensation is recognized only when the fair value of the underlying stock exceeds the exercise price of the option at the date of grant. The exercise price of all options equaled or exceeded market price of the stock at the date of grant. Accordingly, no compensation cost has been recognized for the options issued. Had compensation cost been determined based on the fair value of the options at the grant dates, the

Company's net loss would have been adjusted to the pro forma amounts for the years ended as indicated below. Stock based awards to nonemployees are accounted for under the fair value method of accounting.

	2002	2001	2000
Net loss			
As reported	$(7,626,224)	$(21,073,592)	$(1,195,640)
Pro forma	$(8,035,906)	$(21,360,468)	$(1,366,787)

The fair value of each grant is estimated on the date of grant using the Black-Scholes options-pricing model with the following weighted-average assumptions used for grants in 2002, 2001 and 2000, respectively: No expected dividends, expected volatility of 33%, 28% and 24%, risk-free interest rate of 3.22%, 3.64% and 5.85% and expected lives of 4 and 3 years for incentive options issued in 2002 and 2001, respectively, and .4 and 1.5 years for warrants and 3 years for incentive options issued in 2000. The volatility assumptions were developed using a peer group of similar energy companies.

The Black-Scholes options valuation model was developed for use in estimating the fair value of traded options which 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 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 options.

Property and Equipment

Property and equipment are stated at cost and are depreciated using the straight-line method over the estimated useful lives of the assets, ranging from three through 25 years. Major classes of property and equipment consisted of the following at December 31:

	2002	2001
Equipment	$1,047,989	$1,054,006
Automobiles and trucks	33,086	40,055
Furniture and fixtures	148,730	144,867
Land and buildings	137,625	137,535
Office equipment	94,868	89,856
	1,462,298	1,466,319
Less accumulated depreciation and amortization	710,819	575,015
	$ 751,479	$ 891,304

Earnings (Loss) Per Common Share

Basic earnings (loss) per common share is computed by dividing the net earnings (loss) by the weighted average number of common shares outstanding for the period. Diluted earnings (loss) per share is based on the assumption that stock options and warrants are converted into common shares using the treasury stock method and convertible bonds and debentures are converted using the if-converted method. Conversion or exercise is not assumed if the results are antidilutive.

Potential common shares relating to options, preferred stock and convertible bonds and debentures excluded from the computations of diluted earnings (loss) per share because they are antidilutive are as follows:

	Year ended December 31,		
	2002	2001	2000
Employee stock options	1,514,459	1,770,000	1,642,000
Convertible bonds and debentures	5,768,903	6,216,022	6,531,880
Preferred stock	1,784,197	—	—

Class B, C and D Warrants have a weighted average exercise price of $4.50, $6.00 and $10.00, respectively, for all periods presented. The average weighted exercise price of Class B, C and D Exchange Warrants is $3.60, $4.80 and $8.00, respectively, for all periods presented.

Employee stock options have a weighted average exercise price of $5.59 and $4.52 for the years ended December 31, 2002 and 2001, respectively.

Preferred stock is convertible from the date of issuance until redemption at 100% of the redemption price amount into common stock of the Company at a conversion rate between 1 to 1 and 1 to .5 (Note E).

The Convertible Bonds and Debentures may be converted from the date of issuance until maturity at 100% of principal amount into common stock of the Company at prices ranging from approximately $5.00 to $50.00 (Note D).

Goodwill

During 2001 and 2000, goodwill was amortized using the straight-line method over a 15 year life. The Company adopted SFAS No. 142, *Goodwill and Other Intangible Assets,* effective January 1, 2002 and as such, has not subsequently recorded any amortization of goodwill. Under the new rules, companies would only adjust the carrying amount of goodwill or indefinite life intangible assets upon an impairment.

The Company retained an independent outside valuation expert to develop the fair value analysis to assist the Company in conducting the testing for impairment of its goodwill, all of which arose in its acquisition of Pedco, which provides turnkey operations and well services. The results of the analysis indicated that no impairment of goodwill had occurred. The Company has set the beginning of the second quarter (April) as the annual period for goodwill impairment testing. The results will be reported no later than June 30 of each year.

The following reconciles reported net loss and related per share amounts to amounts that would have been presented exclusive of amortization expense recognized for goodwill that is no longer being amortized:

	Year ended December 31,		
	2002	2001	2000
Report net loss	$(7,626,224)	$(21,073,592)	$(1,195,640)
Goodwill amortization	—	269,572	102,231
Adjusted net loss	$(7,626,224)	$(20,804,020)	$(1,093,409)
Net loss per share—basic and diluted			
Reported net loss	$ (.44)	$ (1.20)	$ (.10)
Goodwill amortization	—	.01	.01
Adjusted net loss	$ (.44)	$ (1.19)	$ (.09)

Recent Accounting Pronouncements

In June 2001, FASB issued SFAS No. 143, *Accounting for Asset Retirement Obligations*, and in August 2001, issued SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the asset retirement cost should be allocated to expense using a systematic and rational method. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002. SFAS No. 144 addresses financial accounting and reporting for the impairment of long-lived assets and for long-lived assets to be disposed of. It supersedes, with exceptions, SFAS No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of*, and is effective for fiscal years beginning after December 15, 2001. The adoption of SFAS No. 144 had no impact on the Company's consolidated financial position or results of operations. The Company is currently assessing the impact of SFAS No. 143.

In April 2002, FASB issued SFAS No. 145, *Rescissions of FASB Statements 4, 44, and 62, Amendment of FASB Statement 13, and Technical Corrections*. With the rescission of SFAS No. 4, gains and losses on extinguishments of debt should be classified as ordinary items unless they meet the criteria for extraordinary item classification in Opinion 30. The Company adopted this standard effective January 1, 2002 and as such, has reported the extinguishments of the contingent repurchase obligation as an ordinary item for the year ended December 31, 2002.

In June 2002, the FASB issued SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*, which replaces Emerging Issues Task Force Issue No. 94-3, *Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)*. The new standard required companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to an exit or disposal plan. The statement will effect exit or disposal activities initiated after December 31, 2002.

In December 2002, the FASB issued SFAS No. 148, *Accounting for Stock-Based Compensation—Transition and Disclosure*, which amended SFAS No. 123, *Accounting for Stock-Based Compensation*. The new standard provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. Additionally, the statement amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in the annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used in reported results. This statement is effective for financial statements for fiscal years ending after December 15, 2002. In compliance with SFAS No. 148, the Company has elected to continue to follow the intrinsic value method in accounting for its stock-based employee compensation arrangement as defined by Accounting Practices Bulletin No. 25.

In November 2002, FASB Interpretation 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others* (FIN 45), was issued. FIN 45 requires a guarantor entity, at the inception of a guarantee covered by the measurement provisions of the interpretation, to record a liability for the fair value of the obligation undertaken in issuing the guarantee. The Company previously did not record a liability when guaranteeing obligations unless it became probable that the Company would have to perform under the guarantee. FIN 45 applies prospectively to guarantees the Company issued or modifies subsequent to December 31, 2002, but has certain disclosure requirements effective for interim and annual periods ending after December 15, 2002. The Company has historically issued guarantees only on a limited basis and does not anticipate FIN 45 will have a material effect on its 2003 financial statements. Disclosures required by FIN 45 are not required because the Company does not have any existing guarantees at December 31, 2002.

In January 2003, the FASB issued FASB Interpretation 46 (FIN 46), *Consolidation of Variable Interest Entities*. FIN 46 clarifies the application of Accounting Research Bulletin 51, *Consolidated Financial Statements*, for certain entities that do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties or in which equity investors do not have the characteristics of a controlling financial interest ("variable interest entities"). Variable interest entities within the scope of FIN 46 will be required to be consolidated by their primary beneficiary. The primary beneficiary of a variable interest entity is determined to be the party that absorbs a majority of the entity's expected losses, receives a majority of its expected returns, or both. FIN 46 applies immediately to variable interest entities created after January 31, 2003, and to variable interest entities in which an enterprise obtains an interest after that date. It applies in the first fiscal year or interim period beginning after June 15, 2003, to variable interest entities in which an enterprise holds a variable interest that it acquired before February 1, 2003. The Company is in the process of determining what impact, if any, the adoption of the provisions of FIN 46 will have upon its financial condition or results of operations.

The Company believes it is possible that certain oil and gas exploration partnerships not consolidated with the Company may be considered variable interest entities which could require consolidation under FIN 46. These partnerships were formed to participate with the Company in the exploration, development and production of oil and gas properties and the Company has certain contingent repurchase obligations. The Company's maximum loss exposure relating to the partnerships under these contingent repurchase obligations is the unrecovered capital contributions of certain partners of approximately $24,941,000. However, the Company would obtain partnership oil and gas properties which would reduce the loss, if any, on the repurchase of partnership interests. Unaudited information with respect to these entities for the year ended December 31, 2002 are as follows: total assets of approximately $9,300,000, total liabilities of approximately $2,800,000 and partners capital of approximately $6,500,000.

The amortized cost, unrealized gains and losses and fair values of the Company's available-for-sale securities held are summarized as follows:

	December 31, 2002	December 31, 2001
U.S. Treasury Bonds, stripped of interest, maturing 2002 through 2023, aggregate par value of $17,780,000 and $19,107,000, respectively		
Amortized cost	$8,255,373	$8,542,626
Gross unrealized gains	1,614,300	464,517
Gross unrealized losses	—	(28,465)
Estimated fair value	$9,869,673	$8,978,678

During 2002, 2001 and 2000, the Company recognized approximately $461,000, $(3,100) and $39,000, respectively, of unrealized gains (losses) on its trading securities and $28,000, $21,000 and $549,000, respectively, of realized gains from its investments in trading and available-for-sale securities. During 2002, 2001 and 2000, the Company recognized realized gains of approximately $28,000, $21,000, $542,000, respectively, resulting from the release of such securities due to cash distributions to investors of affiliated partnerships made from proceeds from sales of oil and gas and the release of the Company's obligation related to securing its commitment under certain repurchase agreements (Notes G and I). Gross gains (losses) recognized in earnings attributable to transfers of available-for-sale securities to trading securities were $28,104, $21,019 and $541,722 in 2002, 2001 and 2000, respectively.

The amortized cost and estimated fair values of available-for-sale securities, by contractual maturity, at December 31, 2002 are shown below.

	Amortized cost	Estimated fair value
Due after five years through ten years	$4,099,394	$4,822,474
Due after ten years	4,155,979	5,047,199
Total	$8,255,373	$9,869,673

NOTE C—SALE OF ASSETS

Pinnacle Assets

During 2001, the Company initiated a plan to dispose of substantially all assets of Pinnacle which was completed on February 14, 2002 for a purchase price of $4.2 million to Basic Energy Services, Inc. ("Basic Energy"). Under the purchase agreement dated December 31, 2001, Basic Energy paid the Company $3.7 million in cash at the closing and $500,000 in contract drilling services credits issued by Basic Energy, which may be utilized by the Company over a three-year period with a maximum of $25,000 in any month. Additionally, the Company entered into a non-compete agreement with Basic Energy.

In connection with the plan of disposal, the Company determined that the carrying value of Pinnacle's assets exceeded their fair values. Accordingly, an impairment expense of approximately $825,000, which is included as part of depreciation, depletion and amortization, and represents the excess of the carrying value of $4,568,000 over the fair value of $3,743,000, has been charged to operations in 2001. The fair value is based on the net selling price of the completed transaction.

	Carrying value	Fair value
Goodwill	$ 223,042	$ —
Property and equipment	4,345,156	3,742,941
	$4,568,198	$3,742,941

Kirby Decker Acreage

During June 2002, the Company initiated a plan to dispose of its Kirby Decker acreage, which was completed in August 2002. The Company sold all of its 24,133 gross (22,075 net) acres, which was located in Bighorn County, Montana for proceeds of approximately $895,000. In connection with the disposal, the Company determined that the carrying value of this property exceeded its fair value. Accordingly, an impairment expense of approximately $1,100,000, was included as part of depreciation, depletion and amortization expense for the year ended December 31, 2002. The fair value was based on the selling price of the property.

Atlantic Rim Project

The Company signed a property exchange and development agreement with Anadarko E&P Company LP, a wholly owned subsidiary of Anadarko Petroleum Corporation, on December 13, 2002. As a result of these transactions, the Company effectively sold a partial interest in unproved properties and recognized a gain of approximately $4,300,000 after recovery of its unproved property costs.

Pursuant to an exchange agreement, the Company conveyed its interest in certain coalbed methane properties of approximately 86,000 net acres within a defined area of mutual interest (the "AMI Area") located in the Washakie Basin, Carbon County, Wyoming. Anadarko conveyed its interest in certain acreage in the AMI with each party owning a 50% interest in approximately 140,000 net acres in the AMI.

The Company received $12,000,000 in cash and a deferred payment commitment of $6,000,000 for the three (3) year period commencing August 1, 2002. Anadarko will pay for the Company's proportionate share of the AMI costs, as defined, associated with exploration and development of oil and gas properties for up to $2,000,000 for each of the three years until Anadarko has paid $2,000,000 for each such twelve-month period. Subject to mutually agreed upon force majeure events, on each August 1, Anadarko will pay the Company the difference, if any, between $2,000,000 and the amount of costs and expenses actually paid by Anadarko during the preceding year.

NOTE D—LONG-TERM DEBT

Debentures consist of the following at December 31:

	2002	2001
Secured Convertible Debentures, matured in August 31, 2002.	$ —	$ 470,000
Sinking Fund Convertible Debentures, matured in August 31, 2002.	—	55,000
Sinking Fund Debentures, due December 31, 2007, bearing interest at 12%, due in monthly payments. Annual Sinking Fund payments, based on 20% of total outstanding principal, commencing on December 31, 2002.	14,376,000	15,390,000

	2002	2001
Secured Convertible Debentures, due December 31, 2009, bearing interest at 12%, due in monthly payments. As of December 31, 2002 and 2001, principal collateralized by $790,000 and $840,000, respectively, each year, principal amount of zero coupon U.S. Treasury Bonds due November 15, 2009.	790,000	840,000
Secured Convertible Bonds, due December 31, 2010, bearing interest at 12%, due in monthly payments. As of December 31, 2002 and 2001, principal collateralized by $1,715,000 and $1,740,000, respectively, principal amount of zero coupon U.S. Treasury Bonds due November 15, 2010.	1,715,000	1,740,000
Sinking Fund Convertible Debentures, due December 31, 2010, bearing interest at 13.02%, due in monthly payments. Annual Sinking Fund payments, based on 8.33% of total outstanding principal, commenced on December 31, 1999.	14,780,200	15,095,200
Sinking Fund Convertible Debentures, due December 31, 2015, bearing interest at 13.02%, due in monthly payments. Annual Sinking Fund payments, based on 5.88% of total outstanding principal, commenced on December 31, 1999.	12,137,500	12,737,500
Secured Convertible Bonds, due December 31, 2016, bearing interest at 12%, due in monthly payments. As of December 31, 2002 and 2001, principal collateralized by $1,460,000 and $1,580,000, respectively, principal amount of zero coupon U.S. Treasury Bonds due November 15, 2016.	1,460,000	1,580,000
Sinking Fund Convertible Debentures, due December 31, 2017, bearing interest at 12%, due in monthly payments. Annual Sinking Fund payments, based on 5.56% of total outstanding principal, commenced on December 31, 1999.	6,590,000	7,215,000
Secured Convertible Bonds, due December 31, 2020, bearing interest at 12%, due in monthly payments. As of December 31, 2002 and 2001, principal collateralized by $1,635,000 and $1,780,000, respectively, principal amount of zero coupon U.S. Treasury Bonds due November 15, 2020.	1,635,000	1,780,000
Secured Convertible Bonds, due December 31, 2022, bearing interest at 12%, due in monthly payments. As of December 31, 2002 and 2001, principal collateralized by $1,186,000 and $1,236,000, respectively, principal amount of zero coupon U.S. Treasury Bonds due November 15, 2022.	1,186,000	1,236,000
	54,669,700	58,138,700
Less current maturities	5,466,970	4,747,370
Long-term portion	$49,202,730	$53,391,330

Other long-term liabilities consists of the following at December 31:

	2002	2001
Note payable; paid in full during 2002.	$ —	$374,321
Other miscellaneous long-term debt, primarily collateralized by treasury stock, effective interest rates of approximately 10%	1,532,109	47,591
	1,532,109	421,912
Less current maturities	178,980	392,721
Long-term portion	$1,353,129	$ 29,191

During 2002, the Company entered into an agreement to purchase 702,500 shares of common stock from a shareholder through the issuance of a non-interest bearing note. The company discounted the non-interest bearing note at 10% and the outstanding balance at December 31, 2002 was approximately $984,000, net of discount of $549,425, which is included in other long-term liabilities. The note requires monthly payments of $13,333 until August of 2012 and is collateralized by the treasury stock. In the event of default as defined by the agreement, the only remedy by the shareholder will be the issuance of the common stock.

During 2000, the Company issued $15,390,000 12% Sinking Fund Debentures, due December 31, 2007. The Company also issued 400 Class D Warrants to purchase common stock of the Company at $10.00 per share with each $50,000 of face value. Brokers also received 200 of the same Class D Warrants for each $50,000 of face value as well as broker commissions. The fair value of the Class D Warrants of approximately $40,000 has been recognized as debt issue costs. During 2002, the Company exchanged preferred stock for 2007 debentures with an outstanding principal of $978,600. The estimated fair value of the preferred stock was based on sales to third-party accredited investors which equaled the carrying value of the debenture. As such, no gain or loss was recognized in 2002.

The Convertible Bonds and Debentures may be converted from the date of issuance until maturity at 100% of principal amount into common stock of the Company at prices which generally increase over the term of the bonds and debentures and range from approximately $4.50 to $50.00. In 2002 and 2001, debenture holders converted $85,000 and $10,000 principal amount of notes into approximately 8,500 and 1,300 shares of common stock, respectively. Additionally, the Company issued approximately 8,000 shares of common stock to certain exchange bond holders. During 2000, debenture holders converted $10,250,000 principal amounts of notes into approximately 1,367,000 shares of common stock. Conversions of debt would increase the numbers of shares outstanding at December 31 as follows:

2002	Maturity date	Outstanding principal amount	Per share conversion price	Common shares if converted
Secured Convertible 12% Bond	December 31, 2009	$ 790,000	$ 8.00	98,750
Secured Convertible 12% Bond	December 31, 2010	1,715,000	8.00	214,375
Sinking Fund 13.02% Bond	December 31, 2010	14,780,200	5.00	2,956,040
Sinking Fund 13.02% Bond	December 31, 2015	12,137,500	8.00	1,517,188
Secured Convertible 12% Bond	December 31, 2016	1,460,000	8.00	182,500
Sinking Fund 12% Bond	December 31, 2017	6,590,000	10.00	659,000
Secured Convertible 12% Bond	December 31, 2020	1,635,000	20.00	81,750
Secured Convertible 12% Bond	December 31, 2022	1,186,000	20.00	59,300
Sinking Fund 12% Bond	December 31, 2007	14,376,000	—	—
		$54,669,700		5,768,903

2001	Maturity date	Outstanding principal amount	Per share conversion price	Common shares if converted
Secured Convertible 12% Bond	August 31, 2002	$ 470,000	$ 4.50	104,444
Sinking Fund 12% Bond	August 31, 2002	55,000	4.50	12,222
Secured Convertible 12% Bond	December 31, 2009	840,000	7.00	120,000
Secured Convertible 12% Bond	December 31, 2010	1,740,000	7.00	248,571
Sinking Fund 13.02% Bond	December 31, 2010	15,095,200	5.00	3,019,040
Sinking Fund 13.02% Bond	December 31, 2015	12,737,500	8.00	1,592,188
Secured Convertible 12% Bond	December 31, 2016	1,580,000	7.00	225,714
Sinking Fund 12% Bond	December 31, 2017	7,215,000	10.00	721,500
Secured Convertible 12% Bond	December 31, 2020	1,780,000	17.50	101,714
Secured Convertible 12% Bond	December 31, 2022	1,236,000	17.50	70,629
Sinking Fund 12% Bond	December 31, 2007	15,390,000	—	—
		$58,138,700		6,216,022

2000	Maturity date	Outstanding principal amount	Per share conversion price	Common shares if converted
Secured Convertible 12% Bond	August 31, 2002	$ 505,000	$ 4.50	112,222
Sinking Fund 12% Bond	August 31, 2002	55,000	4.50	12,222
Secured Convertible 12% Bond	December 31, 2009	840,000	7.00	120,000
Secured Convertible 12% Bond	December 31, 2010	1,765,000	7.00	252,143
Sinking Fund 13.02% Bond	December 31, 2010	15,215,000	5.00	3,043,000
Sinking Fund 13.02% Bond	December 31, 2015	12,977,500	8.00	1,622,188
Secured Convertible 12% Bond	December 31, 2016	1,625,000	7.00	232,143
Sinking Fund 12% Bond	December 31, 2017	7,225,000	7.50	963,333
Secured Convertible 12% Bond	December 31, 2020	1,770,000	17.50	101,143
Secured Convertible 12% Bond	December 31, 2022	1,286,000	17.50	73,486
Sinking Fund 12% Bond	December 31, 2007	15,390,000	—	—
		$58,653,500		6,531,880

The holders of the Secured Convertible Debentures and Sinking Fund Convertible Debentures may tender to the Company up to 10% of the aggregate debentures issued.

The estimated principal that can be tendered by the Secured Convertible and Sinking Fund Debenture holders, including contractual maturities, is as follows:

Fiscal year ending December 31	
2003	$ 5,466,970
2004	5,466,970
2005	5,466,970
2006	5,466,970
2007	5,466,970
Thereafter	27,334,850
	$54,669,700

Annual sinking fund requirements are as follows:

Fiscal year ending December 31	
2003	$ 3,631,751
2004	3,771,656
2005	3,968,781
2006	4,124,204
2007	4,248,871
Thereafter	11,770,766
	$31,516,029

NOTE E—STOCKHOLDERS' EQUITY

During 2002, the Company issued 359,687 shares of convertible preferred stock ("preferred stock") through a private placement with accredited investors at a price of $12 per share for gross proceeds of $4,316,244. Also, during 2002, the Company issued 1,342,960 shares of preferred stock to six affiliated limited partnerships under a partnership recapitalization offering at a price of $12 per share based on third-party sales to accredited investors (see Note J) and exchanged 81,550 shares of preferred stock for 2007 debentures (see Note D). The preferred stock has an 8% cumulative dividend, payable quarterly. Preferred dividends on the shares of approximately $16,000 was accrued at December 31, 2002 and paid in January 2003. The holders of the preferred stock are not entitied to vote except as defined by the agreement or as provided by applicable law. The preferred stock may be voluntarily converted at the election of the holder, commencing one year after the date of issuance. Each outstanding redeemable convertible preferred share is convertible into common stock of the Company based on the table below. The conversion rate is subject to adjustment as defined by the agreement.

	Preferred to common
Period	
Until June 30, 2004	1 to 1
July 1, 2004 through June 30, 2006	1 to .75
July 1, 2006 through redemption	1 to .50

Additionally, commencing seven years after the date of issuance, holders of the preferred stock may elect to require the Company to redeem their preferred stock at a redemption price equal to the liquidation value of $12 per share, plus accrued but unpaid dividends, if any ("Redemption Price"). Upon the receipt of a redemption election, the Company, at its option, shall either: (1) pay the holder cash in the amount equal to the Redemption Price or (2) issue to holder shares of common stock as defined by the agreement.

On September 6, 2001, the Board of Directors approved the issuance of 2,520,613 stock options to officers and employees under certain plans subject to shareholder approval. These plans were approved at the annual shareholder meeting in 2002. As a result, the Company issued and granted a total of 2,505,242 options exercisable at $10 per share. The options are exercisable at a price not less than the fair market of the stock at the date of grant, have an exercisable period of five years and generally are fully vested at the date of grant.

In September 2000, the Company adopted an employee stock option plan for certain employees with a maximum of 1,975,000 shares which may be issued and granted a total of 1,642,000 options exercisable at $4.00 per share. During 2001, the Company issued and granted a total of 153,000 options under the plan. During 2002, options under this plan were not granted by the Company. The options are exercisable at a price not less than the fair market of the stock at the date of grant, have an exercisable period of five years and generally vest 25% after one year, 50% after two years and the final 25% three years after the date of grant. A total of 1,050,000 options granted in 2000 to certain of the employees vest 50% upon grant and 25% each on the second and third anniversaries of the date of grant.

On September 30, 2000, the Company extended the expiration of Class B and C Warrants from September 30, 2000 to December 31, 2000 and recognized an expense of approximately $139,000 due to the change in fair value of the extended warrants. In May 2000, the Company issued 29,000 shares of common stock to two former employees in exchange for exercise of employee warrants. As part of severance arrangements, in a cashless exercise one employee exchanged 60,000 warrants for 24,000 shares of common stock. Compensation expense of $96,000 was recognized as a result of this exercise. The second employee exercised 5,000 warrants at the exercise price of $3.68 per share.

The Company's Class B Warrants, which expired on December 31, 2000, enabled the holders to purchase shares of common stock at an exercise price of between $2.50 and $4.50 per share, subject to certain antidilution provisions. The Company's Class C Warrants, which expired on December 31, 2000, enabled the holders to purchase shares of common stock at an exercise price of between $4.00 and $6.00 per share, subject to certain antidilution provisions. The Company's Class D Warrants, which expired on December 31, 2000, enabled the holders to purchase shares of common stock at an exercise price of between $10.00 and $20.00 per share, subject to certain antidilution provisions. The affiliated partnerships, certain brokers, employees and others held the warrants.

A summary of the status of the Company's options issued to employees as of December 31, 2002, 2001 and 2000 and changes during the years ended on those dates is presented below for employees.

	Incentive Options
Options outstanding—January 1, 2000	—
Issued	1,642,000
Options outstanding—December 31, 2000	1,642,000
Issued	153,000
Exercised	—
Expired	—
Forfeited	(25,000)
Options outstanding—December 31, 2001	1,770,000
Issued	2,505,242
Exercised	—
Expired	—
Forfeited	(2,760,783)
Options outstanding—December 31, 2002	1,514,459
Weighted average fair value of options granted during 2000	$ .56
Weighted average fair value of options granted during 2001	$ .73
Weighted average fair value of options granted during 2002	$ .06
Options exercisable at December 31, 2002	1,340,459
Weighted average exercise price of options	$ 5.59

A summary of the status of the Company's Warrants issued to nonemployees, which expired on December 31, 2000 and the changes during the years ended December 31, 2000 are presented below. The average weighted exercise price of Class B, C and D warrants is $4.50, $6.00 and $10.00, respectively. The average weighted exercise price of Class B, C and D Exchange Warrants is $3.60, $4.80 and $8.00, respectively.

	Class B Warrants	Class C Warrants	Class D Warrants
Warrants outstanding—January 1, 2000	1,522,269	1,022,343	1,039,193
Issued	26,559	215,036	649,604
Exercised	(863,821)	(625,996)	(869,900)
Modified as Exchange Warrants	(550)	(16,859)	(11,532)
Expired	(684,457)	(594,524)	(807,365)
Warrants outstanding—December 31, 2000	—	—	—
Weighted average fair value of warrants granted in 2000	$ 1.20	$ —	$ .22

	Class B Exchange Warrants	Class C Exchange Warrants	Class D Exchange Warrants
Warrants outstanding—January 1, 2000	53,274	498,123	410,172
Issued	688	21,086	14,492
Exercised	(45,357)	(393,993)	(308,799)
Modified as Exchange Warrants	(8,605)	(125,216)	(115,865)
Warrants outstanding—December 31, 2000	—	—	—
Weighted average fair value of exchange warrants granted in 2000	$ .52	$ .04	$ —

NOTE F—INCOME TAXES

The Company and its subsidiaries file a consolidated income tax return.

The Company's effective income tax rate differed from the federal statutory rate as follows:

	2002	2001	2000
Income taxes at federal statutory rate	$(2,753,056)	$ (7,113,443)	$(546,598)
Change in valuation allowance	1,812,915	11,560,422	(5,297)
Nondeductible expenses	55,126	264,101	120,798
State income taxes at statutory rate	(485,833)	(1,255,314)	(96,458)
Adjustment of estimated income tax provision of prior year	899,550	(3,312,841)	121,294
Other	298	8,775	(5,739)
	$ (471,000)	$ 151,700	$(412,000)

The components of the net deferred tax asset are as follows as of December 31:

	2002	2001
Deferred tax assets		
Net operating loss carryforward	$22,868,443	$15,176,559
Organization costs	—	87,659
Oil and gas properties and tangible equipment	2,240,782	6,086,792
Contingent repurchase obligation	—	1,406,542
Other	134,422	471,623
	25,243,647	23,229,175
Less valuation allowance	23,955,687	22,142,772
Total deferred tax assets	1,287,960	1,086,403
Deferred tax liabilities		
Capitalized intangible assets	636,162	930,628
Net unrealized gain on investments	651,798	155,775
Total deferred tax liabilities	1,287,960	1,086,403
Net deferred tax asset	$ —	$ —

The valuation allowance increased (decreased) $1,812,915, $11,560,422 and $(5,297) for the years ended December 31, 2002, 2001 and 2000, respectively.

A valuation allowance for deferred tax assets is required when it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of this deferred tax asset depends on the Company's ability to generate sufficient taxable income in the future. Manage-ment believes it is more likely than not that the net deferred tax asset will not be realized by future operating results.

At December 31, 2002, the Company had net operating loss carryforwards for federal income tax purposes of approximately $57,200,000 which begin to expire in 2012.

NOTE G—COMMITMENTS AND CONTINGENCIES

General Commitments

The Company has entered into various commitments and operating agreements related to development and production of certain oil and gas properties. It is management's belief that such commitments, as stated below, will be met without significant adverse impact to the Company's financial position or results of operations.

The Company has entered into employment agreements with certain key executives. Under the terms of these agreements, the executive is entitled to termination compensation equal to at least two years annual salary if terminated without cause or in the event of a change in control. The maximum termination compensation for all executives is $2,355,000.

Oil and Gas Partnerships

The Company is the managing general partner in various oil and gas partnerships. Accordingly, the Company is unconditionally liable for liabilities which may be incurred by such partnerships. Additionally, the Company has indemnified various working interest (general) partners of affiliated partnerships against any liability which may be incurred in connection with the partnerships, in excess of such partner's interest, in the undistributed net assets of the partnership and insurance proceeds thereof which continues through the date of termination of the partnership from 2025 to 2030, unless the partnership is dissolved at an earlier date. The partnerships have no liabilities except accounts payable to the Company for lease operating and administrative expenses.

In connection with the release of Treasury securities held for drilling programs formed between 1994 and 1998, the Company undertook to contribute additional oil and gas leases to these partnerships on a "best efforts" basis. The values of the properties to be contributed may vary, at the sole discretion of the Company, from zero up to 50% of the value of the U.S. Treasury Bonds released by the partnerships.

The Company has a gas purchase contract with Western Gas related to its Piper Federal lease. The contract is for the purchase of a minimum of 2,500 Mcf of gas per day at the wellhead. The contract commences on February 1, 2001 and expires on February 1, 2005. If the Company fails to deliver 2,500 Mcf of gas per day, Western Gas may charge the Company a deficiency fee. The deficiency fee is defined as the amount of deficient Mcf times 90% (amount below 2,500 Mcf times 90%) times the deficiency rate of $0.42 per Mcf representing gathering, compression and transportation charges. The maximum deficiency charge for 2003, 2004 and 2005 totals approximately $720,000. During 2002 and 2001, the Company was in compliance with the purchase contract.

The Company has a gas purchase contract with Western Gas related to its Haight Less lease through December 31, 2004. The contract is for the purchase of a minimum of 550 Mcf of gas per day at the wellhead. Since approximately 1998, the contract has been extended on a year-by-year basis. If the Company fails to deliver 550 Mcf of gas per day, Western Gas reduces the sales price by a nominal amount. During 2002 and 2001, the Company was in compliance with the purchase contract.

The Company has a transportation contract with Williston Basin Interstate ("WBI") related to its LX Bar lease through October 8, 2006. If the Company fails to deliver 6,000 Mcf of gas per day, WBI may charge the Company a transportation fee. The transportation fee is defined as the amount of deficient Mcf times the transportation rate of approximately $0.43 per Mcf. During 2002 and 2001, the Company paid a transportation fee of approximately $276,000 and $172,000, respectively. The maximum deficiency charge through the period of contract expiration is approximately $3,600,000.

Repurchase Agreements

Under certain repurchase agreements, the investor partners in certain affiliated partnerships have a right to have their interests purchased by a repurchase agent. Such purchase price is calculated at a formula price and is payable in seven to 25 years from the date of admission to the partnership. For certain affiliated partnerships formed prior to 1998, the maximum purchase price for all such interests was fully secured at maturity by zero coupon U.S. Treasury Bonds held by an independent trust company. The face amounts of such securities are released to the Company when equal amounts of cash distributions are made to investors. At December 31, 2002 and 2001, the face amounts of U.S. Treasury Bonds securing the Company's obligation under such repurchase agreements were $4,380,000 and $4,603,000, respectively, and the market value of these U.S. Treasury Bonds was approximately $1,839,838 and $1,589,409, respectively. Under certain other repurchase agreements, the investor partners have a right to have their interests purchased by a repurchase agent under the same formula price seven years from the date of the original partnership investment. The repurchase agent's performance is unconditionally guaranteed by the Company; however, any payment to be made under this guarantee are included in the Company's maximum loss exposure to partnerships disclosed in Note A.

Harbor View Horizons Corp. ("Harbor View") is a financial services company that served as a remarketing agent for the limited partnerships formed in 1994 and 1995 under a remarketing agreement, wherein Harbor View agreed to accept tenders from investor partners who desired to sell their interest and withdraw from the partnerships at a designated future date that was typically 15 to 22 years from the date of formation of the partnerships. To assure Harbor View's ability to perform, the Company placed zero coupon U.S. Treasury Bonds in an escrow account with Chase Manhattan Bank, N.A. Harbor View was not affiliated with the limited partnerships or the Company. Commencing in 1996, the partnerships ceased using Harbor View as a remarketing agent. Instead, the remarketing feature was replaced with a "buy-sell" clause or agreement directly with the Company contained within the respective limited partnership agreements. Subsequent to 1995, the Company made investments in Harbor View through loans to it for other finance activities unrelated to the remarketing agreements.

In determining the amount of the contingent repurchase obligation, the present value of the obligation is computed based on the excess of the formula purchase price over the estimated discounted present value of future net revenues of proved developed and undeveloped reserves of each partnership, net of future capital costs and the Company's working interest. The partnerships' proved undeveloped leases must be drilled by the Company using funds from an outside party or from the Company to provide future revenues which satisfy the contingent repurchase obligation. During 2002, the Company contributed leases to certain partnerships to satisfy this obligation and recognized an expense of approximately $254,000. The Company has estimated that these wells will require approximately $30,200,000 of development costs in partnerships in 2003 through 2008 for drilling and completing these wells. These development costs, the partnerships' future net revenues and the contingent repurchase obligation are based on reserve studies of independent petroleum engineers and actual amounts may differ from the estimates. Based upon this calculation using prices at December 31, 2002, the Company recorded no contingent repurchase obligation. A similar analysis has been performed in all prior years.

Included in other current assets in the accompanying consolidated financial statements at December 31, 2001 are amounts due from the Company's repurchase agent of approximately $325,000 related to short-term, noninterest-bearing loans, which were collected during 2002.

Trust Indenture Agreements

Under certain Trust Indenture Agreements, the Company has purchased zero coupon U.S. Treasury Bonds to secure repayment of the outstanding principal amount of debentures outstanding when due at maturity. At December 31, 2002 and 2001, the face amounts of U.S. Treasury Bonds securing the Company's obligation under the Trust Indenture Agreements were $13,610,000 and $14,504,000, respectively, and the market values of these U.S. Treasury Bonds were approximately $8,108,000 and $7,386,000, respectively.

Leases

In July 1997, the Company entered into an office lease in New York City, which commenced October 1997 and expires in March 2008. The lease can be canceled by the Company after five years subject to a cancellation fee of approximately $120,000. On June 1, 2000, Pedco entered into an office lease in Albuquerque, New Mexico expiring May 31, 2003. On January 22, 2000, Pedco entered into an office lease in Gillette, Wyoming expiring February 28, 2001 with an option to renew on a yearly basis. This lease was renewed in 2002.

Future minimum annual rental payments, which are subject to escalation and include utility charges as of December 31, 2002, are as follows:

Year ending December 31	
2003	$189,911
2004	155,686
2005	155,686
2006	155,686
2007	155,686
Thereafter	38,921
	$851,576

Rent expense under these leases was approximately $254,000, $281,000 and $243,000 for the years ended December 31, 2002, 2001 and 2000, respectively.

Litigation

The Company is a party to various matters of litigation arising in the normal course of business. Management believes that the ultimate outcome of the matters will not have a material effect on the Company's financial condition or results of operations.

NOTE H—EMPLOYEE BENEFIT PLANS

The Company has a retirement plan covering substantially all qualified corporate employees under section 401(k) of the Internal Revenue Code. Under the plan, participants may contribute up to 22% of their compensation to their plan accounts. The Company contributed for each participant a matching contribution equal to 50% of the participant's contribution to a maximum of 6% of each employee's annual compensation. The Company may also make discretionary contributions. The Company's expenses under the plan were approximately $78,000, $92,000 and $35,000 for the years ended December 31, 2002, 2001 and 2000, respectively.

NOTE I—RELATED PARTY TRANSACTIONS

Affiliated Partnerships

The Company contributed mineral rights with an agreed-upon fair value of $184,916 and $361,115 during 2002 and 2001, respectively, to affiliated partnerships in exchange for a 10% interest in these partnerships. The mineral rights remain at cost in the Company's property accounts. Affiliated partnerships paid $5,163,250, $14,443,250 and $44,479,750 to the Company during 2002, 2001 and 2000, respectively, under fixed price turnkey drilling contracts. At December 31, 2002 and 2001, accounts receivable from affiliated partnerships were approximately $921,000 and $802,000, respectively, relating primarily to administrative costs paid by the Company on behalf of the partnerships.

The Company purchased lease and well equipment and certain leasehold interests at estimated fair value from affiliated partnerships during the years ended December 31, 2002, 2001 and 2000 for approximately $0, $75,000 and $355,000, respectively. During the years ended December 31, 2002, 2001 and 2000, the Company expensed lease operating expenses of approximately $0, $1,329,000 and $3,234,000, respectively, for affiliated partnerships which were recorded in general and administrative expenses as marketing cost.

Joint Venture Agreements

Prior to September 1, 2000, the Company and Pedco each owned, net of third-party interests, a 50% interest in the Pedco Group, a joint venture formed for the purpose of participating in the horizontal drilling and re-completing of existing oil wells. Subsequent to the acquisition of Pedco, the Company owns 100% of the Pedco Group.

The Pedco Group is party to separate joint venture agreements with the affiliated partnerships. The agreements form a joint venture between the Pedco Group and each partnership for the purpose of participating in the drilling and re-completing of oil wells. Under the terms of the agreements, property acquisition and capital equipment costs are borne by the Pedco Group. Generally, intangible drilling and development costs are borne by the partnerships. Additionally, the Company issued warrants to buy shares of the Company's common stock to these partnerships as a capital contribution and to certain brokers who sell these limited partners' interests as additional commissions for partnerships prior to 2001. The fair value of these warrants are recognized as either reductions of turnkey revenue (partnership warrants) or marketing expense (broker warrants) based on the fair value of the warrant issued (Note E) and increases to paid-in capital. Charges to operations for these warrants were approximately $120,000 for the year ended December 31, 2000.

Under the terms of the joint venture agreement, the affiliated partnerships have an initial 75% interest in the aggregate net profits of the properties. Once the partnerships have received distributions equal to the payments under the turnkey contract, the Pedco Group will receive an additional reversionary interest of 15% and the partnerships' interest will be reduced to 60%.

The partnerships are parties to a standard form of operating agreement with Pedco (the "Operator") pursuant to which the Operator will be responsible for the operation of the wells. Also, the Operator is engaged to supervise all drilling and re-completion of wells, on behalf of all working interests, and has full control of all operations of the wells as covered under the operating agreement. Each partnership pays the Operator its pro rata share of monthly operating expenses.

In May 1999, the Company entered into an agreement with Magness Petroleum Company ("Magness") to form a joint venture for the purpose of participating in the horizontal drilling and re-completing of existing oil wells and the drilling of new oil wells within the Wilmington Oil Field in Los Angeles County, California.

On or about September 28, 1999, Magness filed suit against Warren Resources, Inc.., alleging claims for breach of written contract, breach of oral contract, dissolution of joint venture, accounting and declaratory relief. Upon defendants' motion, the case was sent to arbitration. As part of the arbitration, the defendants asserted cross-claims against Magness for breach of written contract, gross negligence, breach of fiduciary duty and actual and constructive fraud. Shortly before the arbitration commenced, Magness amended its complaint to add certain fraud claims against defendants. In February 2001, the arbitrator rendered his opinion, finding that Magness had breached the joint venture agreement at issue and that the defendants had not breached the joint venture agreement. Additionally, the arbitrator found there was no fraud or damages on either side, that the joint venture agreement should remain in force and that the Company should recover approximately $320,000 of charges from Magness which was collected during 2001. Magness has initiated new arbitration in August 2001, seeking dissolution of the joint venture and has sought court action to change to a different arbitrating organization for dispute resolution. The Company has filed a court action to compel Magness to submit disputes to the original arbitrating organization to which the parties agreed. On January 3, 2002, the Los Angeles Superior Court granted the Company's petition, denied Magness' petition and ordered Magness to discontinue its efforts to remove the controversy from the jurisdiction and to proceed with arbitration. Magness appealed this ruling on February 6, 2002, the Court of Appeal of the State of California stayed the January 3, 2002 order to proceed with arbitration, pending a hearing on the lower court's ruling. The hearing was held before the Court of Appeal on September 27, 2002, and on November 18, 2002 the Court of Appeal rendered its opinion that the written agreement to arbitrate before the original arbitrating organization entered into in December 1999 only covered matters and issues presented in and relating to the arbitration and that pursuant to the arbitration clause of the Joint Venture Agreement new issues or disputes not covered by the Arbitration Agreement should be brought before the AAA. In response to a Motion for Rehearing filed by the Company, the Court of Appeal ordered on December 17, 2002 that its original opinion be modified to clarify that there has not been a determination whether Magness has complied in full with the arbitrator's Final Award. The Company believes that Magness has not fully complied and is in default of the Final Award and is seeking enforcement of the Final Award, along with damages incurred by reason of Magness' failure to comply. In order to clarify what specific matters continue under arbitration pursuant to the original written stipulation for arbitration, on January 12, 2003, the Company filed a Motion for Clarification in the Superior Court of California along with a Motion for Enforcement of Final Award with the Arbitrator. A initial hearing of the Motion for Clarification was held in the Superior Court on February 20, 2003. Subsequently, the Court instructed the parties to present their proposed Orders and supporting briefs before April 4, 2003. The Company believes that any subsequent findings will not have a significant adverse effect on the Company's financial position or operation.

Other Income

In December of 2002, the Company's Executive Vice President died in an accident. The Company carried life insurance in the amount of approximately $3,750,000 on this officer. At December 31, 2002, a receivable for these insurance proceeds, which was collected in February of 2003, was recorded and income of approximately $3,750,000 was recognized in Interest and Other Income on the Statement of Operations.

NOTE J—RECAPITALIZATION OFFERS

During the fourth quarter of 2002, the Company, acting as the MGP, commenced a vote solicitation of the limited partners of the affiliated partnerships (the "Partnership Recapitalization Offers") to: (1) obtain the requisite two-thirds affirmative vote of their respective partners to convert the drilling program from a Delaware limited partnership into a Delaware limited liability company (the "LLC") wherein all LLC members would have limited liability, including the Company, and (ii) upon conversion to an LLC, the Company would contribute as additional capital to the LLC its unregistered 8% convertible preferred stock with a value equal to between 110% to 120% of the potential repurchase price of consenting members' interests ("Preferred Members") calculated as of December 31, 2002. The Company would receive additional standard membership interests in the LLC and be specially allocated, pro rata as a standard member, the Preferred Members' interests in the oil and gas properties owned by their respective programs (the "Recapitalization"). Acceptance by Preferred Members of the Recapitalization, terminated their repurchase rights under the original buy/sell agreements. At December 31, 2002, six of the 13 programs obtained the requisite votes to convert to LLCs and on average 71% of the program members elected to become Preferred Members in their LLC. As a result, the Company issued 1,342,960 preferred shares to the six LLCs as a capital contribution, with an estimated fair value of $16,115,520, and received its pro rata share of additional standard membership interests in the LLCs. The fair value of the preferred shares was based on actual cash sales to independent parties in this time period. Due to the increase in control of these six affiliated partnerships, the Company has consolidated these entities for financial reporting purposes at

December 31, 2002. The Company accounted for these acquisitions as purchase transactions with the estimated fair value of assets acquired and liabilities assumed in the acquisition as follows:

Estimated fair value of assets acquired	
Current assets	$ 4,350
Oil and gas properties	25,252,358
Total fair value of assets	25,256,708
Liabilities assumed	
Accounts payable	171,110
Minority interest	8,970,078
Total liabilities assumed	9,141,188
Cost of acquisition	$16,115,520

The following summarizes pro forma unaudited results of operations for the years ended December 31, 2002 and 2001 as if these acquisitions had been consummated immediately prior to January 1, 2001. These pro forma results are not necessarily indicative of future results.

	Pro Forma (unaudited) Year ended December 31, 2002	2001
Revenues	$30,780,346	$ 55,876,324
Net loss	$ (7,526,873)	$(25,970,741)
Loss per share	$ (0.43)	$ (1.48)

The operations of these affiliated partnerships will be included in the accompanying consolidated financial statements subsequent to December 31, 2002.

NOTE K—FAIR VALUE OF FINANCIAL INSTRUMENTS

The following methods and assumptions were used to estimate the fair value of each class of financial instruments and does not purport to represent the aggregate net fair value of the Company.

Cash and Cash Equivalents. The balance sheet carrying amounts of cash and cash equivalents approximate fair values of such assets.

U.S Treasury Bonds—Trading Securities and Available-For-Sale. The fair values are based upon quoted market prices for those or similar investments.

Restricted Cash. The balance sheet carrying value amounts of restricted cash approximates fair value of such assets.

Convertible Debentures. Fair values of fixed rate convertible debentures were calculated using interest rates in effect as of year end for similar instruments with the other terms unchanged.

Other Long-Term Liabilities. The carrying amount approximates fair value due to the short duration to maturity or on the current rates offered to the Company for long-term liabilities of the same remaining maturities.

Contingent Repurchase Obligation. The balance sheet carrying amounts of the contingent repurchase obligation approximate fair value of such liability.

	2002		2001	
	Fair value	Carrying amount	Fair value	Carrying amount
Financial assets				
Cash and cash equivalents	$ 23,184,936	$ 23,184,936	$ 22,923,605	$ 22,923,605
U.S. Treasury bonds and other investments—trading securities	78,383	78,383	205,989	205,989
U.S. Treasury bonds—available-for-sale	9,869,673	9,869,673	8,978,678	8,978,678
Restricted cash	3,637,775	3,637,775	—	—
Financial liabilities				
Fixed rate debentures	$(61,691,195)	$(54,669,700)	$(62,463,469)	$(58,138,700)
Other long-term liabilities	(1,532,109)	(1,532,109)	(421,912)	421,912
Contingent repurchase obligation	—	—	(3,318,993)	(3,318,993)

NOTE L—ACQUISITION OF BUSINESS

On September 1, 2000, the Company acquired Pedco for 1,600,000 shares of its common stock valued at $4.00 per share by an independent party. Pedco has been the contract operator for the majority of the Company's wells in New Mexico, Texas and Wyoming and owned a 25% interest in the Company's consolidated subsidiary, Pinnacle. The Company accounted for the acquisition as a purchase transaction and costs in excess of net assets acquired of approximately $3,765,000 will be amortized over its estimated life of 15 years. The fair value of receivables and investments were based upon their net realizable values and the value of the investment in Pinnacle was based upon a bona fide offer of purchase of Pinnacle from an unrelated party. Property and equipment values were estimated by field personnel. Goodwill predominately relates to the acquired technical, engineering and operating personnel of Pedco.

The estimated fair market values of the assets acquired and liabilities assumed in the acquisition of Pedco are as follows:

Estimated fair value of assets acquired	
Cash	$ 629,896
Receivables	1,571,546
Investments	131,478
Property and equipment	14,446
Investment in Pinnacle	1,503,798
Goodwill	3,764,903
Other	94,351
Total fair value of assets	7,710,418
Liabilities assumed	
Accounts payable	1,310,418
Estimated fair value of acquisition	$6,400,000

The following summarizes pro forma unaudited results of operations for the year ended December 31, 2000 as if the acquisition had been consummated immediately prior to January 1, 2000. These pro forma results are not necessarily indicative of future results.

	Pro Forma (unaudited)
	Year ended December 31, 2000
Revenues	$57,861,658
Net loss	$ (996,746)
Loss per share	
Basic and diluted	$ (.07)

The operations of Pedco are included in the accompanying consolidated financial statements subsequent to the acquisition.

NOTE M—OIL AND GAS INFORMATION

Costs related to the oil and gas activities of the Company were incurred as follows for the years ended December 31:

	2002	2001	2000
Property acquisition—unproved	$ 176,030	$ 6,912,000	$15,918,470
Property acquisition—proved	163,254	—	1,191,595
Exploration costs	471,948	3,763,417	999,873
Development costs	3,888,221	6,269,004	2,847,563
	$4,699,453	$16,944,421	$20,957,501

Of the above development costs incurred for the years ended December 31, 2002, 2001 and 2000, the amounts of approximately $343,000, $390,000 and $59,000, respectively, were incurred to develop proved undeveloped properties from the prior year.

During the years ended December 31, 2002, 2001 and 2000, exploration costs of approximately $472,000, $282,000 and $340,000, respectively, were expensed.

The Company had the following aggregate capitalized costs relating to the Company's oil and gas activities at December 31:

	2002	2001
Unproved oil and gas properties	$31,296,142	$67,171,193
Proved oil and gas properties	73,558,896	19,188,469
	104,855,038	86,359,662
Less accumulated depreciation, depletion and amortization	56,170,676	46,384,864
	$48,684,362	$39,974,798

The following table sets forth the Company's results of operations from oil and natural gas producing activities for the years ended December 31:

	2002	2001	2000
Revenues	$ 592,528	$ 948,270	$ 200,330
Production costs	(294,520)	(285,980)	(14,634)
Exploration costs	(471,948)	(281,776)	(340,713)
Depreciation, depletion and amortization	(9,606,606)	(12,899,648)	(2,476,036)
Loss from oil and gas producing activities	$(9,780,546)	$(12,519,134)	$(2,631,053)

In the presentation above, no deduction has been made for indirect costs such as corporate overhead or interest expense. No income taxes are reflected above due to the Company's tax loss carryforwards. Additionally, production costs reported above excludes the amount that the Company pays on behalf of the affiliated partnerships and is reimbursed.

Depreciation, depletion and amortization expense was $9,606,606, $12,899,648 and $2,476,036 or $120, $258 and $52 per equivalent Mcf of production for the years ended December 31, 2002, 2001 and 2000, respectively. These amounts include impairment expenses of $9,299,981, $11,112,516 and $2,102,624 for the years ended December 31, 2002, 2001 and 2000, respectively, which was based on prices at December 31 for 2002 and 2000 and March 15, 2002 for 2001.

NOTE N—OIL AND GAS RESERVE DATA (UNAUDITED)

The following estimates of proved reserve quantities and related standardized measure of discounted net cash flows are estimates only, and do not purport to reflect realizable values or fair market values of the Company's reserves. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of producing oil and gas properties.

Accordingly, these estimates are expected to change as future information becomes available. All of the Company's reserves are located in the United States.

Proved reserves are estimated reserves of crude oil (including condensate and natural gas liquids) and natural gas that 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 reserves are those expected to be recovered through existing wells, equipment and operating methods.

The standardized measure of discounted future net cash flows is computed by applying year-end prices of oil and gas (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved oil and gas reserves, less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, less estimated future income tax expenses (based on year-end statutory tax rates, with consideration of future tax rates already legislated) to be incurred on pretax net cash flows less tax basis of the properties and available credits, and assuming continuation of existing economic conditions. The estimated future net cash flows are then discounted using a rate of 10% per year to reflect the estimated timing of the future cash flows.

The following summaries of changes in reserves and standardized measure of discounted future net cash flows were prepared from estimates of proved reserves developed by independent petroleum engineers.

Summary of Changes in Proved Reserves

	Year ended December 31,					
	2002		2001		2000	
	Bbls	Mcf	Bbls	Mcf	Bbls	Mcf
	(Amounts in thousands)					
Proved reserves						
Beginning of year	8,478	2,495	11,770	11,516	10,389	4,993
Purchase of reserves in place	3,538	1,770	—	—	—	1,540
Discoveries and extensions	—	5,294	4	947	19	1,734
Revisions of previous estimates	312	(1,002)	(3,293)	(9,936)	1,365	3,279
Production	(4)	(55)	(3)	(32)	(3)	(30)
End of year	12,324*	8,502*	8,478	2,495	11,770	11,516
Proved developed reserves						
Beginning of year	8	1,648	243	8,034	240	2,174
End of year	404	4,544	8	1,648	243	8,034

* Includes reserves of 1,195 Bbls and 577 Mcf attributable to consolidated subsidiaries in which there is an average 34% minority interest.

Standardized Measure of Discounted Future Net Cash Flows
Relating to Proved Oil and Gas Reserves

	December 31,		
	2002	2001	2000
	(Amounts in thousands)		
Future cash inflows	$ 362,982	$122,032	$337,921
Future production costs and taxes	(47,661)	(25,676)	(56,671)
Future development costs	(43,003)	(31,556)	(33,848)
Future income tax expenses	(110,939)	(4,749)	(66,233)
Net future cash flows	161,379	60,051	181,169
Discounted at 10% for estimated timing of cash flows	(89,961)	(40,539)	(92,073)
Standardized measure of discounted future net cash flows	$ 71,418*	$ 19,512	$ 89,096

* Includes $10,462 attributable to consolidated subsidiaries in which there is an average 34% minority interest.

Changes in Standardized Measure of Discounted Future Net Cash Flows Related to Proved Oil and Gas Reserves

	Year ended December 31,		
	2002	2001	2000
	(Amounts in thousands)		
Sales, net of production costs and taxes	$ (298)	$ (662)	$ (200)
Discoveries and extensions	5,550	272	5,393
Purchases of reserves in place	30,944	—	4,537
Changes in prices and production costs	46,531	(42,613)	6,103
Revisions of quantity estimates	1,884	(15,976)	22,214
Net changes in development costs	(1,048)	2,823	(12,071)
Interest factor—accretion of discount	2,047	11,783	7,975
Net change in income taxes	(41,566)	27,762	(9,177)
Changes in production rates (timing) and other	7,862	(52,973)	4,119
Net increase (decrease)	51,906	(69,584)	28,893
Balance at beginning of year	19,512	89,096	60,203
Balance at end of year	$ 71,418	$ 19,512	$ 89,096

Estimated future net cash flows represent an estimate of future net revenues from the production of proved reserves using current sales prices, along with estimates of the operating costs, production taxes and future development and abandonment costs (less salvage value) necessary to produce such reserves. The average prices used at December 31, 2002, 2001 and 2000 were $27.15, $13.87 and $20.37 per Bbl and $3.36, $1.76 and $8.53 per Mcf, respectively. No deduction has been made for depreciation, depletion or any indirect costs such as general corporate overhead or interest expense.

Operating costs and production taxes are estimated based on current costs with respect to producing oil and natural gas properties. Future development costs are based on the best estimate of such costs assuming current economic and operating conditions. The future cash flows estimated to be spent to develop the Company's portion of proved undeveloped properties in the years ended December 31, 2003, 2004 and 2005 are $1,422,000, $5,397,000 and $7,422,000, respectively.

Income tax expense is computed based on applying the appropriate statutory tax rate to the excess of future cash inflows less future production and development costs over the current tax basis of the properties involved, less applicable carryforwards, for both regular and alternative minimum tax.

The future net revenue information assumes no escalation of costs or prices, except for oil and natural gas sales made under terms of contracts which include fixed and determinable escalation. Future costs and prices could significantly vary from current amounts and, accordingly, revisions in the future could be significant.

NOTE O—QUARTERLY INFORMATION (UNAUDITED)

Summarized quarterly financial data for the years ended December 31, 2002 and 2001 are as follows:

	2002				
	Quarter				Year
	First	Second	Third	Fourth	
Revenues	$8,092,392	$ 7,553,080	$ 5,794,244	$ 8,170,574	$29,610,290
Gross profit (loss)	2,667,784	(524,307)	1,489,551	(4,861,856)	(1,228,828)
Net loss	574,420	(2,587,965)	(1,088,942)	(4,523,737)	(7,626,224)
Loss per share					
Basic and diluted	$ .03	$ (.15)	$ (.06)	$ (.27)	$ (.44)

	2001				
	Quarter				Year
	First	Second	Third	Fourth	
Revenues	$11,057,663	$14,641,153	$14,757,521	$13,002,913	$53,459,250
Gross profit (loss)	341,499	1,240,828	1,202,611	(14,412,568)	(11,627,630)
Net loss	(1,185,559)	(858,508)	(497,193)	(18,532,332)	(21,073,592)
Loss per share					
Basic and diluted	$ (.07)	$ (.05)	$ (.03)	$ (1.06)	$ (1.20)

Quarterly and year-to-date computations of per share amounts are made independently. Therefore, the sum of quarterly per share amounts may not agree with per share amounts for the year.

During the fourth quarter of 2002, the Company had the following significant adjustments:

- Recognized impairment on oil and gas properties of approximately $9,300,000 as a result of the net capitalized costs exceeding the expected future net cash flow based on engineering estimates (see Note M).
- Recorded life insurance proceeds of $3,750,000 relating to the death of Executive Vice-President, James C. Johnson, Jr. (see Note I).
- Recognized a gain of $4,300,000 as a result of the sale of oil and gas properties to Anadarko.
- Reversed previously recognized turnkey revenue of $4,300,000 relating to wells that were previously in drilling programs but were part of the asset sale of Anadarko.

The effect of these adjustments was to increase the net loss by approximately $5,550,000 or $(.32) per basic and diluted share for the quarter and year ended December 31, 2002.

During the fourth quarter of 2001, the Company had the following significant adjustments:

- Entered into an agreement to sell substantially all assets of Pinnacle that resulted in an impairment of approximately $825,000 (see Note C).
- Recorded a contingent repurchase obligation of approximately $3,300,000 (see Note G).
- Recognized impairment on oil and gas properties of approximately $11,100,000 as a result of the net capitalized costs exceeding the expected future net cash flow based on engineering estimates (see Note M).

The effect of these adjustments was to increase the net loss by approximately $15,225,000 or $(.87) per basic and diluted share for the quarter and year ended December 31, 2001.

NOTE P—SEGMENT INFORMATION

The Company's operating activities can be divided into four major segments: turnkey contracts, oil and gas marketing, oil and gas exploration and production operations and well services. The Company drills oil and natural gas wells for Company-sponsored drilling partnerships and retains an interest in each well. The Company also markets natural gas for affiliated partnerships. The Company charges Company-sponsored partnerships and other third parties competitive industry rates for well operations and gas gathering. Segment information for the years ended December 31 is as follows:

	2002	2001	2000
Revenues from external customers			
Turnkey contracts	$ 5,841,110	$30,102,946	$33,984,960
Oil and gas marketing	11,272,398	14,866,954	15,420,917
Oil and gas operations	4,879,302	948,270	200,330
Well services	1,895,453	5,574,335	4,297,414
Other	5,722,027	1,966,745	3,044,495
Total	$29,610,290	$53,459,250	$56,948,116
Intersegment revenue			
Well services	$ —	$ 983,910	$ 226,179
Other	25,660	228,857	235,598
Total	$ 25,660	$ 1,212,767	$ 461,777
Interest and other income			
Turnkey contracts	$ 3,368	$ 23,003	$ 309,275
Oil and gas marketing	—	—	—
Oil and gas operations	31,439	81,001	8,260
Well services	2,540	17,183	—
Other	5,246,155	2,084,752	2,375,209
Intersegment elimination	(25,660)	(228,857)	(235,598)
Total	$ 5,257,842	$ 1,977,082	$ 2,457,146

	2002	2001	2000
Consolidated revenues			
Total segment revenue	$ 23,888,263	$ 52,476,415	$ 54,129,800
Other	5,747,687	2,195,602	3,280,093
Intersegment elimination	(25,660)	(1,212,767)	(461,777)
Total	$ 29,610,290	$ 53,459,250	$ 56,948,116
Interest expense			
Turnkey contracts	$ 5,577	$ 116,933	$ 478,832
Oil and gas marketing	—	—	—
Oil and gas operations	—	—	—
Well services	28,957	292,515	335,111
Other	6,303,757	5,595,643	6,389,505
Elimination of intersegment	(25,660)	(228,857)	(235,598)
Total	$ 6,312,631	$ 5,776,234	$ 6,967,850
Depreciation, depletion and amortization			
Turnkey contracts	$ 102,942	$ 100,450	$ 89,301
Oil and gas marketing	—	—	—
Oil and gas operations	9,606,606	12,899,648	2,476,036
Well services	47,643	961,253	362,682
Other	172,971	500,768	137,441
Total	$ 9,930,162	$ 14,462,119	$ 3,065,460
Operating income (loss)			
Turnkey contracts	$ 3,835,194	$ 2,458,217	$ 11,218,926
Oil and gas marketing	150,876	(431,888)	(379,341)
Oil and gas operations	(6,021,629)	(12,438,133)	(2,622,793)
Well services	982,515	2,367,993	915,717
Other	(7,044,180)	(12,878,081)	(10,740,149)
Total	$ (8,097,224)	$(20,921,892)	$ (1,607,640)
Assets			
Turnkey contracts	$ 34,982,047	$ 31,688,540	$ 49,587,787
Oil and gas marketing	192,642	192,642	192,642
Oil and gas operations	54,582,576	56,931,996	37,621,395
Well services	94,338	4,471,379	4,364,664
Other	18,410,691	1,615,657	36,882,410
Total	$108,262,294	$ 94,900,214	$128,648,898
Capital expenditures			
Turnkey contracts	$ —	$ 42,616	$ —
Oil and gas marketing	—	—	192,642
Oil and gas operations	4,744,732	16,955,738	20,764,859
Well services	—	92,315	5,253
Other	5,013	43,418	22,974
Total	$ 4,749,745	$ 17,134,087	$ 20,985,728