FORM 10−K

WARREN RESOURCES INC − WRES

Filed: March 09, 2006 (period: December 31, 2005)

Annual report which provides a comprehensive overview of the company for the past year

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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, 2005

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)

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

489 Fifth Avenue, New York, NY 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 if the registrant is a well−known seasoned issuer, as defined in Rule 405 of the Securities Act. ☒ Yes ☐ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. ☐ Yes ☒ No

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non−accelerated filer (as defined in Rule 12b−2 of the Act).

Large accelerated filer ☐	Accelerated filer ☒	Non−accelerated filer ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b−2 of the Act). ☐ Yes ☒ No

The aggregate market value of the registrant's common stock held by non−affiliates of the registrant on June 30, 2005 was $404,893,198.

The number of shares of registrant's common stock outstanding as of March 7, 2006 was 52,835,248 shares.

DOCUMENTS INCORPORATED BY REFERENCE:

Certain portions of the registrant's definitive proxy statement to be filed with the Securities and Exchange Commission pursuant to Regulation 14A not later than April 30, 2006, in connection with the registrant's 2006 Annual Meeting of Stockholders, are incorporated herein by reference into Part III of this Annual Report on Form 10−K.

WARREN RESOURCES, INC.
FORM 10−K

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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 Warren E&P, Inc.

For abbreviations or definitions of certain terms used in the oil and gas industry and in this annual report, please refer to the section entitled "Glossary of Abbreviations and Terms".

PART I

CAUTIONARY NOTE REGARDING FORWARD−LOOKING STATEMENTS

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 27A of the Securities Act of 1933, as amended (the “Securities Act”), and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”), that involve a number of risks and uncertainties.

These forward−looking statements include, among others, the following:

- our growth strategies;
- our reserve estimates;
- our ability to successfully and economically explore for and develop oil and gas resources;
- anticipated trends in our business;
- our future results of operations;
- our liquidity and ability to finance our exploration and development activities;
- market conditions in the oil and gas industry;
- our ability to make and integrate acquisitions, including our recent acquisition of the North Wilmington Unit within the Los Angeles Basin;
- the impact of environmental and other governmental regulation.

These statements may be found under “Risk Factors”, “Management’s Discussion and Analysis of Financial Condition and Results of Operation”, “Business and Properties” and other sections of this annual report. Forward−looking statements are typically identified by use of terms such as “may”, “will”, “could”, “should”, “expect”, “plan”, “project”, “intend”, “anticipate”, “believe”, “estimate”, “predict”, “potential”, “pursue”, “target” or “continue”, the negative of such terms or other comparable terminology, although some forward−looking statements may be expressed differently.

The forward−looking statements contained in this annual report are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management’s assumptions about future events may prove to be inaccurate. Management cautions all readers that the forward−looking statements contained in this annual report are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or the forward−looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward−looking statements due to a number of factors, including:

- the failure to obtain sufficient capital resources to fund our operations;
- an inability to replace our reserves through exploration and development activities;
- unsuccessful drilling activities;
- a decline in oil or natural gas production or oil or natural gas prices;
- incorrect estimates of required capital expenditures;

- increases in the cost of drilling, completion and gas gathering or other costs of production and operations;
- impact of environmental and other governmental regulation;
- hazardous and risky drilling operations; and
- an inability to meet growth projections.

You should also consider carefully the statements under “Risk Factors” and other sections of this annual report, which address additional factors that could cause our actual results to differ from those set forth in the forward−looking statements.

All forward−looking statements speak only as of the date of this annual report. We do not intend to publicly update or revise any forward−looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward−looking statements attributable to us or persons acting on our behalf.

Items 1 and 2: Business and Properties

Overview

We are a growing independent energy company engaged in the exploration and development of domestic onshore natural gas and oil reserves. We focus our efforts primarily on the exploration and development of coalbed methane, or CBM, natural gas properties located in the Rocky Mountain region and on our waterflood oil recovery programs in the Wilmington field within the Los Angeles Basin of California.

As of December 31, 2005, we owned natural gas and oil leasehold interests in approximately 277,001 gross (154,100 net) acres, 93% of which are undeveloped. Substantially all our undeveloped acreage is located in the Rocky Mountains and the Wilmington field. We have identified approximately 2,202 drilling locations on our acreage in the Rocky Mountains, primarily on 80−acre and 160−acre well spacing. Additionally, we have identified approximately 500 drilling locations in the Wilmington field.

As of December 31, 2005, we had estimated net proved reserves of 326.8 Bcfe, with a PV−10 value of $637.9 million, based on a reserve report prepared by Williamson Petroleum Consultants, Inc. These estimated net proved reserves are located on less than 10% of our total net acreage. Based on our preliminary results to date, we believe that a substantial amount of our remaining undeveloped CBM acreage in the Washakie Basin in the Rocky Mountain Region has commercial potential.

Effective January 1, 2005, we acquired all of the right, title and interests in the Wilmington Townlot Unit for $14.8 million. As a result of this acquisition, our working interests in our Wilmington Townlot Unit holdings increased to approximately 98.5%. We were also appointed operator of record for this unitized oil field. For 2005, our total net production from the Wilmington Townlot Unit was 0.9 Bcfe. In June 2005, we commenced drilling seven spot water flood patterns in the Terminal oil zone and drilled 13 producers and 3 injector wells in 2005, and also drilled a well in the Ranger oil zone in December 2005. At December 31, 2005, the estimated net proved reserves attributable to the Wilmington Townlot Unit were 182.7 Bcfe.

Effective December 31, 2005, we also acquired all of the right, title and interests in the North Wilmington Unit and became operator of this unitized oil field. The acquired North Wilmington Unit assets include a 100% working interest and an approximate 84.5% net revenue interest in the field, including existing wells, certain equipment and certain surface properties. At December 31, 2005, the estimated net proved reserves attributable to the North Wilmington Unit were 118.7 Bcfe.

As of December 31, 2005, we had interests in 265 gross (134 net) producing wells and are the operator of record or co−operator for 85% of these wells. Through our joint venture agreements, we actively participate in operating activities for most of the wells for which we are not operator of record. On December 31, 2005, our total daily production was 25.5 MMcfe/d gross (8.7 MMcfe/d net). For 2006, we have a total capital expenditure budget of approximately $108.1 million.

Business Strategy

The principal elements of our business strategy are designed to grow our oil and gas reserves, production volumes and cash flows at a positive return on invested capital. We plan to focus on the following:

- *Exploit Existing Properties Through the Drillbit.* We intend to increase our proved reserves and production by drilling numerous locations identified on our Rocky Mountain CBM properties and in our Wilmington field, we have identified a total of 2,702 drilling locations, of which 2,202 are in our Rocky Mountain CBM properties, 450 are in our Wilmington Townlot Unit and 50 are in the North Wilmington Unit. We plan to participate in the drilling of 158 gross wells during 2006, of which 64 are in our Rocky Mountain CBM properties and 94 are in our Wilmington field.
- *Pursue Selective Acquisitions and Joint Ventures.* We believe we are well positioned, given our asset base and technical expertise, to pursue selected acquisitions and attract industry joint venture partners. For example, the acquisitions of the Wilmington Townlot Unit and the North Wilmington Unit. We are also joint venture partners in the Atlantic Rim project in Wyoming with Anadarko Petroleum Corporation, one of the largest independent oil and gas exploration and production companies in the world. We expect to pursue further acquisitions of natural gas and oil properties in areas where we have specific technical knowledge and experience.
- *Reduce Costs Through Economies of Scale and Efficient Operations.* As we continue to increase our production and develop our existing properties, we expect that our unit cost structure will benefit from economies of scale. With respect to our CBM operations, we anticipate reducing unit costs by greater utilization of our existing infrastructure over a larger number of wells. We seek to exert more control over costs and timing in our exploration, development and production activities through our operating activities and relationships with our joint venture partners.

Competitive Strengths

As a result of the following strengths, we believe we are well positioned to execute our business strategy:

- *Substantial Rocky Mountain Undeveloped CBM Acreage Position.* We believe that the Rocky Mountain region is one of the few remaining high potential CBM natural gas provinces in North America. As of December 31, 2005, we have assembled a substantial undeveloped acreage position in the Rocky Mountains of 245,999 gross (140,126 net) acres containing 2,202 identified drilling locations. In the Rocky Mountains, our estimated total net proved reserves of 20.3 Bcf are located on approximately 6% of our total net acreage.
- *Significant Development Opportunity in the Los Angeles Basin of California.* We believe that our Wilmington Townlot Unit, together with the North Wilmington Unit, provide us a significant development opportunity of long−lived oil reserves in a historically prolific basin. The Wilmington Townlot Unit and North Wilmington Unit combined comprise approximately 2,476 gross (2,406 net) acres within the Los Angeles basin and contain 500 identified drilling locations for producing wells. As of December 31, 2005, 90% of our proved reserves in the Wilmington field were undeveloped.

- *Technical Expertise*. Since the beginning of our CBM operations in 1996, we have gained considerable expertise in advanced CBM drilling, completion and re−entry techniques. We also have expertise in directional and horizontal drilling relating to our waterflood recovery program in the Wilmington Townlot Unit.
- *Experienced Management Team*. Our management team has 27 years of experience on average in the oil and gas industry, and our technical professionals have 25 years of experience on average in oil and gas operations. Our personnel have extensive experience in managing large−scale operations in each of our areas of concentration. Most members of our senior management have been with us since the mid−1990s.
- *Incentivized Management Ownership*. The equity ownership of our management team is strongly aligned with that of our stockholders. As of March 7, 2006, our 14 directors and executive officers beneficially owned 5,477,181 shares of common stock, which includes exercisable options to purchase 1,984,283 shares of our common stock.

Areas of Exploration and Development Activities

Our exploration and development activities are focused primarily on CBM projects in the Rocky Mountain region and also on waterflood oil recovery projects in the Wilmington field in California. The table below highlights our main areas of activity:

Area	Gross Acres	Net Acres	Planned Gross Wells in 2006
Washakie Basin:			
Atlantic Rim Project	213,890	113,259	52
Pacific Rim Project	35,846	28,191	11
South Seminoe Prospect	14,187	7,094	1
Powder River Basin	3,110	1,332	—
Wilmington Field	2,476	2,406	94
Other(1)	7,492	1,818	—
Total	277,001	154,100	158

(1) Includes conventional oil and gas properties located primarily in New Mexico, Texas and North Dakota.

Rocky Mountain CBM Projects

Washakie Basin

The Washakie Basin is located in the southeast one−third of the Greater Green River Basin in southwestern Wyoming and represents our largest acreage position. As of December 31, 2005, we had assembled 249,736 gross (141,450 net) acres prospective for CBM development in this area, of which 132,950 net acres are undeveloped. This area contains approximately 2,202 identified drilling locations primarily on 80−acre and 160−acre well spacing. The report prepared by Williamson Petroleum Consultants as of December 31, 2005 estimates that the gross recoverable proved reserves for the 58 CBM wells drilled and their 48 well offsets in our first three CBM pilot programs in this basin were 79.8 Bcf gross (19.8 Bcf net) on 80−acre and 160−acre spacing. We own a 57% average working interest to the base of the Mesa Verde formation in this acreage.

In addition to this acreage, we have the rights to drill and develop the deeper, conventional formations ("deep rights") in some, but not all, of the acreage in the Atlantic Rim Area. We own approximately 90,250 gross (74,175 net) undeveloped acres of deep rights inside the AMI with Anadarko, and approximately 34,510 gross (30,643 net) undeveloped acres of deep rights outside the AMI, for a total of 124,760 gross (104,818 net) undeveloped acres in the entire Atlantic Rim Area. These deep rights are also subject to the pending EIS covering the shallow rights in the Atlantic Rim Area. The EIS contemplates that approximately 200 conventional wells will be drilled to the deep rights owned by Warren and the other operators within the EIS boundary covering the Atlantic Rim Area. We anticipate receiving a Record of Decision approving the EIS in the fourth quarter of 2006

Commercial CBM production in the Washakie Basin was initially established in 2002 on the eastern rim of the Washakie Basin by Warren and Double Eagle Petroleum Co., an independent energy company. Current development in the Washakie Basin is targeting shallow Mesa Verde coalbeds. The Mesa Verde coalbeds in this area differ from those found in the Powder River Basin in that they are thinner zones but have significantly higher gas content, much like the coalbeds found in the Drunkard's Wash field in the Uinta Basin of Utah. CBM field development in the Washakie Basin is usually accomplished by grouping wells into "pods" of 10 to 24 wells, complete with associated infrastructure, including water disposal wells, gathering and compression. The productive pods are typically grouped into individual federal units of up to 25,000 acres each, which facilitates development operations.

Atlantic Rim Project

Our Atlantic Rim project comprises approximately 213,890 gross (113,259 net) acres on the eastern rim of the Washakie Basin. We have drilled a total of 30 CBM wells in the Atlantic Rim project in 2005, for a total of 128 wells. Additionally, upon completion of an ongoing environmental impact study being conducted on the Atlantic Rim area by the Rawlins Office of the Bureau of Land Management ("BLM"), covering approximately 310,000 acres, we plan to significantly increase drilling activities in the Atlantic Rim project. We believe this study should be completed in 2006. Currently we are jointly developing all of our Atlantic Rim projects within the area of mutual interest, or AMI, with Anadarko. Anadarko is the operator of record for the Atlantic Rim project, and under the Anadarko agreements, our personnel and Anadarko's personnel have equal input in decision−making for most decisions, including budgets and drilling.

Sun Dog Unit

Our initial pod, the Sun Dog unit, is a 10−well pilot program drilled in 2001 on 80−acre spacing. In 2004 we drilled an additional 2 CBM gross (0.3 net) wells and a second water injection well. Production commenced from these additional wells in April 2005. The Sun Dog unit commenced production in April 2002 at a gross rate of approximately 200 Mcf/d of gas and 6,000 Bbls/d of water. Since April 2002, production rates from the Sun Dog unit wells have increased steadily to over 5,450 Mcf/d of gas and 13,000 Bbls/d of water. As of December 31, 2005, the wells have continued to exhibit a typical CBM negative decline curve, increasing daily gas production with relative water production rates decreasing as a percentage of gas production. Based on a report from Williamson Petroleum Consultants, as of December 31, 2005, estimated gross ultimate recoverable proved reserves for the 12 producing wells and 8 undrilled offset locations in the Sun Dog unit average 1.2 Bcfe per well. We currently own a working interest of approximately 33% in the wells drilled in the initial pod of the Sun Dog unit. Our working interest in the unit will be approximately 40% if the existing unit is fully drilled and developed.

Blue Sky Unit

Our second producing pod in the Atlantic Rim project, the Blue Sky unit, is a 23−well pilot program originally drilled on 160−acre spacing. This program commenced production in August 2003 and as of December 31, 2005, was producing 340 Mcf/d of natural gas and approximately 17,000 Bbls/d of water. Based on prior desorption, permeability, pressure build−up and other tests, we believe that as the wells dewater, the Blue Sky unit wells should exhibit daily production rates and a CBM negative decline curve similar to other CBM wells. During 2005, we drilled an additional 11 CBM wells in this unit to reduce the well spacing to 80−acres. Based on a report from Williamson Petroleum Consultants, as of December 31, 2005, estimated gross ultimate recoverable proved reserves for the 20 producing wells and 11 undrilled offset locations in the Blue Sky unit average 0.5 Bcfe per well. We currently own an approximate 12% working interest in the wells drilled in the initial pod of the Blue Sky unit. Our working interest in the unit will be approximately 40% if the existing unit is fully drilled and developed.

Red Rim Unit

This pod consists of 16 wells on 160−acre spacing. We completed eight CBM wells and one water injection well during 2003, another eight wells during 2004 and an injector well in 2005. The installation of a gathering system was completed in 2005. These 16 wells are currently in the dewatering stage. We own a working interest of approximately 13% in the wells drilled in the initial pod of the Red Rim unit. Our working interest in the unit will be approximately 46% if the existing unit is fully drilled and developed.

Doty Mountain Unit

The first pod in the Doty Mountain unit consists of 24 wells on 80−acre spacing. These wells plus one water injection well were drilled and completed in 2004. This program commenced production in February 2005 and as of December 31, 2005, was producing over 1,400 Mcf/d of natural gas and approximately 7,300 Bbls/d of water. We currently own an approximate 9% working interest in the wells drilled in the initial pod of the Doty Mountain unit. Our working interest in the unit will be approximately 40% if the existing unit is fully drilled and developed.

Jolly Roger Unit

We are currently developing our first pod in the Jolly Roger unit. This pod consists of 24 wells on 160−acre spacing. We drilled eight wells and one water injection well in 2002 and drilled 16 wells, one water injection well and one monitor well in this unit in 2005. We currently own a working interest of approximately 11% in the wells drilled in the initial pod of the Jolly Roger unit. Our working interest in the unit will be approximately 43% if the existing unit is fully drilled and developed.

Pacific Rim Project

Since 2003, we have been acquiring our Pacific Rim acreage located on the western rim of the Washakie Basin, 60 miles west of our Atlantic Rim project. At December 31, 2005, our Pacific Rim project comprised approximately 35,846 gross (28,191 net) acres. We are the operator of record for the Pacific Rim project, which is not subject to the AMI or joint venture agreements with Anadarko. This property includes four previously drilled CBM test wells from which we obtained technical test data, similar in many respects to the data from our Atlantic Rim wells.

In April 2004, we acquired an existing 6 1/2−mile gas pipeline that connects the Pacific Rim project to a 20−inch main gas pipeline. This pipeline through a connecting pipeline connects to the Kern River pipeline, which carries gas to Bakersfield, California.

We plan to significantly increase our drilling activity in the Pacific Rim project by up to 120 CBM wells, assuming we achieve sustainable commercial rates of production from existing wells. We received approval of an environmental assessment submitted by us to the Rock Springs, Wyoming office of the BLM in the third quarter of 2004.

Pacific Isle Unit

This pod consists of fifteen wells, two of which we acquired with the property, seven of which we drilled in late 2003 and six that were drilled in 2004. We also drilled a water injection well in this unit in 2003. This program commenced production in February 2005 and as of December 31, 2005, was producing over 200 Mcf/d of natural gas and approximately 5,400 Bbls/d of water. We currently own an approximate 20% working interest in the wells drilled in the initial pod of the Pacific Isle unit. Our working interest in the unit will be approximately 80% if the existing unit is fully drilled and developed.

Chicken Springs Unit

We are currently developing our first pod in the Chicken Springs unit. This pod consists of four wells, one of which we drilled in the second quarter of 2004 and three of which we drilled in 2005, including one horizontal CBM well. As of December 31, 2005, the first two Chicken Springs wells were producing over 480 Mcf/d of natural gas. We currently own an approximate 15% working interest in the wells drilled in the initial pod of the Chicken Springs unit. Our working interest in the unit will be approximately 50% if the existing unit is fully drilled and developed.

Rifes Rim Unit

We are currently developing our first pod in the Rifes Rim unit. This pod consists of five wells, one of which we acquired with the property, and four of which were drilled in the fourth quarter of 2004. We expect to drill an additional five CBM wells in the first quarter of 2006. We currently own a working interest of approximately 18% in the wells drilled in the initial pod of the Rifes Rim unit. Our working interest in the unit will be approximately 72% if the existing unit is fully drilled and developed.

South Seminoe Prospect

During 2005, we acquired a 50% working interest in 14,187 gross (7,094 net) acres located in the Hanna Basin of south central Wyoming. Seismic data from this prospect indicates the potential presence of a structure that may contain multiple pay zones from the shallower Shannon zone to the deeper Ten Sleep formation. Warren plans to drill a test well in this project in 2006 and will be the operator of the unit.

Powder River Basin

At December 31, 2005, we owned and operated interests in 76 gross (42.3 net) producing CBM wells in 3,110 gross (1,332 net) acres in the Powder River Basin near Gillette, Wyoming. At December 31, 2005, these wells were producing approximately 3,661 Mcf/d gross (1,278 Mcf/d net). At December 31, 2005, our total estimated net proved reserves in this portion of the Powder River Basin were 5.9 Bcf gross (2.4 Bcf net). Since 2003, we have deepened and recompleted 27 gross (8.6 net) wells in the LX−Bar field in the Powder River Basin to a lower coal seam. At December 31, 2005, gross production from these formerly non−producing wells was 2,654 Mcf/d gross (828 Mcf/d net).

Southern California Projects

Wilmington Townlot Unit

Our Wilmington Townlot Unit is located in the Wilmington field within the Los Angeles Basin of California. The Wilmington field has produced over 2.5 billion barrels of oil since its discovery in the 1930s. Since that time, the Wilmington Townlot Unit, a unitized oil field consisting of 1,440 gross (1,242 net) acres, has produced more than 149 million barrels of oil from primary production. All the working interests in the Wilmington Townlot Unit are subject to the terms and provisions of a unit operating agreement.

Our Wilmington Townlot Unit oil reserves are primarily proved undeveloped, or PUDs. We seek to develop these reserves using directional and horizontal drilling and secondary recovery techniques, such as a waterflood recovery program. As of December 31, 2005, we had 760 Bbls/d gross (551 Bbls/d net) production, compared to 411 Bbls/d gross (218 Bbls/d net) production as of December 31, 2004. In addition, estimated proved reserves as of December 31, 2005 were 38 MMbbls gross (31 MMbbls net), of which 93% are PUDs. Further, as of December 31, 2005, there were 46 gross (41.3 net) producing wells.

Upon acquisition of our initial 50% interest in the Wilmington Townlot Unit in 1999, we entered into a joint venture with an unrelated entity to develop the property through directional drilling, applying secondary recovery techniques, such as waterflood redevelopment.

On January 31, 2005, with an effective date of January 1, 2005, we closed under the purchase and sale agreement and acquired the remaining interests from our Joint Venture partner and its affiliate, in the Wilmington Townlot Unit, including but not limited to:

- all of the oil and gas mineral leases, working interests, net revenue interests, royalty interests, overriding royalty interests, mineral interests, carried interests and farmout rights described in the agreement;
- certain surface properties and surface estates; and
- all oil, gas and water injection wells.

As consideration for the purchase of the assets described above we paid a total cash purchase price of $14.8 million and assumed certain liabilities and obligations associated with the Wilmington Townlot Unit including plugging and abandonment obligations.

The net result of this transaction is to increase our interest in future development activity in the Wilmington Townlot Unit to an approximate 98.5% undivided working interest.

The closing of the Purchase and Sale Agreement occurred on January 31 and February 1, 2005. At the closing, the parties terminated their Joint Venture Agreement dated May 24, 1999, Warren E&P, Inc. was elected the new operator.

North Wilmington Unit

The North Wilmington Unit is located in the Wilmington oil field adjacent to our existing Wilmington Townlot Unit leasehold interests. Since its discovery in the 1930s, the North Wilmington Unit, this unitized oil field consisting of approximately 875 gross and net acres, has produced more than 37.6 million barrels of oil. All working interests in the North Wilmington Unit are subject to the terms and provisions of a unit operating agreement.

On December 9, 2005, we entered into an asset purchase agreement to acquire the North Wilmington Unit. The acquired assets include a 100% working interest and an approximate 84.5% net revenue interest in the field, including existing wells, certain equipment and certain surface properties. On December 30, 2005, with an effective date of December 31, 2005, we closed under the asset purchase agreement and acquired the interests in the North Wilmington Unit including but not limited to:

- all of the oil and gas mineral leases, working interests, net revenue interests, royalty interests, overriding royalty interests, mineral interests, carried interests and farmout rights described in the agreement;
- certain surface properties and surface estates; and
- all oil, gas and water injection wells.

As consideration for the purchase of the NWU assets described above we paid a total cash purchase price of $23 million and assumed certain liabilities and obligations of the sellers associated with the NWU unit including environmental and plugging and abandonment obligations. At the closing, Warren E&P, Inc. was elected the new operator.

The North Wilmington Unit oil reserves are primarily PUDs. Based on a report of Williamson Petroleum Consultants as of December 31, 2005, the estimated net proved reserves attributable to the North Wilmington Unit are 118.7 Bcfe. We seek to develop these reserves using directional and horizontal drilling and secondary recovery techniques, such as a waterflood recovery program. As of December 31, 2005, production from the North Wilmington Unit was 404 Bbls gross (341 Bblsd net).

Drilling Programs

Since 1992, we have sponsored 31 drilling programs that have raised approximately $228 million. Since 2003, we have not sponsored and drilling programs. On behalf of these drilling programs, we have participated in the drilling of approximately 550 conventional, horizontal wells and CBM wells, virtually all of which were operated by us, with approximately 90% of such wells being completed and commercially productive.

Under these programs, we contribute drilling locations and pay all tangible drilling costs, while the other investor partners in the drilling programs pay all intangible drilling costs. Warren E&P, Inc., 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.

We act as the sole managing general partner of each drilling program, and we typically receive a before−payout working interest of 25% (55% after−payout) and drill the wells on a fixed−cost basis. As of December 31, 2005, none of the active 22 drilling programs managed by us had achieved payout status.

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 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.

As of December 31, 2005, investor partners in our drilling programs have received cash distributions ranging from below 14% of original capital contributions for programs formed since 2000; between 14% and 32%, or 52% to 71% after federal tax benefits are included assuming the maximum marginal federal income tax rate, for programs formed between 1997 and 1999; and between 40% and 80%, or 78% to 122% after federal tax benefits are included, assuming the maximum marginal federal income tax rate, for 13 of the 15 programs formed in 1996 or earlier. Cash distributions to investor partners are made monthly. Our drilling programs have distributed approximately $69.6 million to investor partners through

December 31, 2005, of which $62.8 million were from cash flow generated from oil and gas revenues from the respective drilling programs' wells and $6.8 million were from sales of wells or well equipment. Between December 2002 and March 2003, 13 drilling programs converted from Delaware limited partnerships to Delaware LLCs and on average 75% of the drilling program members elected to convert their interests to preferred member interests in their respective LLCs. Preferred member interests have the right to a preferential return and other preferential rights senior to our and other standard member interests. As a result of these conversions, we issued an aggregate of 3,341,559 restricted convertible preferred shares to the LLCs as additional capital contributions and received as consideration additional standard membership interests in the LLCs, which increased our pro rata beneficial interests in the oil and gas wells owned by the LLCs. Also during 2003, we issued an aggregate of 1,048,336 restricted convertible preferred shares to two joint ventures as additional capital contributions and received as consideration additional joint venture interests in the joint ventures, which increased our pro rata beneficial interests in the oil and gas wells owned by the joint ventures. In 2005, upon member's withdrawals from the LLC's or joint ventures, 5,838,161 shares of convertible preferred stock was converted into common stock on a 1 for 1 basis and 70,312 shares of preferred stock was converted into common stock on a 1 for 0.75 basis. In February 2006, we offered to purchase for cash the remaining minority oil and gas interests not already owned by Warren from the LLC's originally formed between 1994 and 1997 based upon their PV−10 value as determined by Williamson Petroleum Consultants, Inc., independent petroleum engineers. If all remaining members in those LLC's approve the sale of the oil and gas interests, we would pay an aggregate cash purchase price of $1.1 million.

To the extent that we have an existing obligation to drill program wells as of December 31, 2005, the drilling programs will continue to participate with us on a pro rata basis in our drilling activities until the wells have been drilled. As of December 31, 2005, we have 4 net wells remaining to be drilled for the drilling programs.

During 2005, we issued 187,500 shares of our common stock in exchange for interests in one of our joint ventures.

In February 2006, we also offered to purchase from the two drilling programs formed in 1998 their oil and gas interests for their PV−10 value at December 31, 2005 as determined by Williamson Petroleum Consultants, Inc., which in the aggregate is $7.6 million. We have proposed to the two partnerships to pay the purchase price in the form of shares of restricted Warren common stock (the "Common Stock"), which shares will be valued based upon a 20% discount from the weighted average sales price for Warren's publicly traded common stock for the forty−five (45) calendar days ending March 31, 2006.

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, 2005, 2004 and 2003 based on reserve reports prepared by Williamson Petroleum Consultants. The PV−10 values shown in the table are not intended to represent the current market value of the estimated natural gas and oil reserves we own.

A portion of our proved developed 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, are based upon certain assumptions of the drilling programs in which we own interests will achieve payout status in the future. As of December 31, 2005, none of the active 22 drilling programs managed by us had achieved payout status.

	Years Ended December 31,		
	2005	2004	2003
Estimated Proved Natural Gas and Oil Reserves:			
Net natural gas reserves (MMcf):			
Proved developed	10,829	8,496	7,006
Proved undeveloped	13,524	10,046	8,442
Total (1)	24,353	18,542	15,448
Net oil reserves (MBbls):			
Proved developed	2,938	395	476
Proved undeveloped	47,477	13,781	14,648
Total (2)	50,415	14,176	15,124
Total Net Proved Natural Gas & Oil Reserves (MMcfe)	326,845	103,601	106,190
Estimated Present Value of Net Proved Reserves:			
PV−10 Value (in thousands)			
Proved developed	$107,639	$ 26,901	$ 20,461
Proved undeveloped	530,280	215,392	162,524
Total (3)	637,919	242,293	182,985
Less: future income taxes, discounted at 10%	175,139	49,648	36,859
Standardized measure of discounted future net cash flows (in thousands) (4)	$462,780	$192,645	$146,126
Prices Used in Calculating Reserves:			
Natural Gas (per Mcf)	$ 9.92	$ 5.30	$ 4.50
Oil (per Bbl)	49.05	37.59	28.45
Proved Developed Reserves (MMcfe)	28,461	10,866	9,862

(1) Included in 2005, 2004 and 2003 reserves, 136 MMcf, 357 MMcf and 1,028 MMcf is attributable to consolidated subsidiaries in which there is an average minority interest of 9%, 23% and 25%, respectively.

(2) Included in 2005, 2004 and 2003 reserves, 922 MBbls, 2,142 MBbls and 2,469 MBbls is attributable to consolidated subsidiaries in which there is an average minority interest of 9%, 23%, and 25%, respectively.

(3) The PV−10 Value represents the discounted future net cash flows attributable to our proved oil and gas reserves before income tax, discounted at 10% per annum. Although it is a non−GAAP measure, we believe that the presentation of the PV−10 Value is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account corporate future income taxes and our current tax structure. We use this measure when assessing the potential return on investment related to our oil and gas properties. Our reconciliation of this non−GAAP financial measure is shown in the table as the PV−10, less future income taxes, discounted at 10% per annum, resulting in the standardized measure of discounted future net cash flows. The standardized measure of discounted future net cash flows represents the present value of

future cash flows attributable to our proved oil and natural gas reserves after income tax, discounted at 10%. In accordance with SEC requirements, our reserves and the future net revenues were determined using realized prices for natural gas and oil at each of December 31, 2005, 2004, and 2003, which were, $9.92 per Mcf of natural gas and $49.05 per barrel of oil at December 31, 2005, $5.30 per Mcf of natural gas and $37.59 per barrel of oil at December 31, 2004 and $4.50 per Mcf of natural gas and $28.45 per barrel of oil at December 31, 2003 These prices reflect adjustment by lease for quality, transportation fees and regional price differences.

(4) Standardized measure of discounted future net cash flows differ from PV−10 value because it includes the effect of future income taxes. Included in 2005, 2004 and 2003 standardized measure of discounted future net cash flows $9,673, $26,054 and $23,017 is attributable to consolidated subsidiaries in which there is an average minority interest of 9%, 23% and 25%, respectively.

The data in the above natural gas and oil reserves table represents estimates only. Oil and natural gas reserve engineering is inherently a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured exactly. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of oil and natural gas that are ultimately recovered. See “Risk Factors”.

PV−10 is equal to the future net cash flows from our proved reserves at December 31, 2005, excluding any future income taxes, discounted at 10% per annum (“PV−10”). Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are proved reserves that are expected to be recovered from new wells drilled to known reservoirs on undrilled acreage for which the existence and recoverability of such reserves can be estimated with reasonable certainty, or from existing wells on which a relatively major expenditure is required to establish production.

PV−10 may be considered a non−GAAP financial measure as defined by Item 10(e) of Regulation S−K and is derived from the standardized measure of discounted future net cash flows which is the most directly comparable GAAP financial measure. PV−10 is a computation of the standardized measure of discounted future net cash flows on a pre−tax basis. We believe that the presentation of the PV−10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account corporate future income taxes and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. However, PV−10 is not a substitute for the standardized measure of discounted future net cash flows.

Due to the volatility of commodity prices, the oil and gas prices on the last day of the period significantly impact the calculation of the PV−10 and the standardized measure of discounted future net cash flows. The present value of future net cash flows does not purport to be an estimate of the fair market value of the Company’s proved reserves. An estimate of fair value would also take into account, among other things, anticipated changes in future prices and costs, the expected recovery of reserves in excess of proved reserves and a discount factor more representative of the time value of money and the risks inherent in producing oil and gas. Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The 10% discount factor used to calculate present value, which is required by Financial Accounting Standard Board pronouncements, may not necessarily be the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate.

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 annual report 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 there from, 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.

With respect to the estimates prepared by Williamson Petroleum Consultants, 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 annual report. 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.

Productive Wells

The following table sets forth our gross and net productive wells as of December 31, 2005:

	Natural Gas Wells		Oil Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
California	0.0	0.0	90.0	78.5	90.0	78.5
New Mexico	20.0	0.7	3.0	0.1	23.0	0.8
Texas.	9.0	1.7	0.0	0.0	9.0	1.7
Wyoming	141.0	52.6	0.0	0.0	141.0	52.6
Other	0.0	0.0	2.0	0.1	2.0	0.1
Total	170.0	55.0	95.0	78.7	265.0	133.7

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:

	Years Ended December 31,					
	2005		2004		2003	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells(1)						
Productive(2)	21.0	2.4	52.0	5.1	16.0	2.8
Nonproductive(3)		—	1.0	0.1	—	—
Development Wells(1)						
Productive(2)	27.0	13.3	14.0	2.1	19.0	3.3
Nonproductive(3)	—	—	1.0	0.3	1.0	0.1
Total	48.0	15.7	68.0	7.6	36.0	6.2

(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, 2005:

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
California	1,125	1,097	1,351	1,309	2,476	2,406
New Mexico	1,386	105	3,602	398	4,988	503
Texas	704	176	—	—	704	176
Wyoming. .	21,034	9,750	245,999	140,126	267,033	149,876
Other	948	419	852	720	1,800	1,139
Total	25,197	11,547	251,804	142,553	277,001	154,100

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 production is attributable to our direct interests in producing properties and the production we are allocated from our interest in our drilling 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 expenses shown relates to our net production.

	Years Ended December 31,		
	2005	2004	2003
Production:			
Natural gas (MMcf)	1,073.5	817.2	785.8
Oil (MBbls)	147.6	68.2	87.4
Total equivalents (MMcfe)	1,958.9	1,226.3	1,310.1
Average Sales Price Per Unit:			
Natural gas (per Mcf)	$ 6.71	$ 5.03	$ 3.70
Oil (per Bbl)	45.75	34.38	25.42
Weighted average (per Mcfe)	7.13	5.26	3.92
Expenses (per Mcfe):			
Lease operating expense (1) (2)	$ 3.64	$ 3.12	$ 2.94

(1) The lease operating expenses for 2004 & 2003 for the Wilmington Townlot Unit that were utilized for this calculation include direct labor that was improperly charged to us by the prior operator of the Wilmington Townlot Unit.

(2) Lease operating expenses related to our CBM operations include costs for operating our commercially productive CBM wells, together with the costs for operating our CBM wells that are still in the dewatering phase and are not yet commercially productive.

Purchasers and Marketing

We sell our natural gas and oil production and that of our drilling programs to various purchasers in the areas where the oil and natural gas is produced. The natural gas is delivered into natural gas pipelines for transportation and is sold to various purchasers for later re−marketing or end use. Our oil is sold to purchasers who take delivery from storage tanks that are located on our property. We are currently able to sell all of the natural gas and oil produced on our behalf and that of our drilling programs. The majority of all of this natural gas and oil is sold under monthly contracts that allow for periodic adjustments in pricing according to market demands.

In addition, approximately 46% of our natural 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 6,000 Mcf/d, which will terminate in October 2006. We sell our natural gas at market price. The marketing of natural gas and oil 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 “Risk Factors”.

For 2005, the largest purchasers for our production and that of our drilling programs primarily included Tenaska Marketing Ventures, Anadarko Energy Services and Lunday−Thagard Company, which accounted for 21%, 16% and 44%, respectively, of the total natural gas and oil sold by us and our drilling programs. We believe that the loss of any of these purchasers would not have a material adverse effect on our operations, as we believe there are a significant number of readily available purchasers in the market.

Our Service and Operational Activities

Our drilling, completion, production, re−entry and land operations are conducted, managed and supervised for us and our drilling programs through Warren E&P, Inc., our wholly owned subsidiary. Through Warren E&P, we employ petroleum engineers, drilling supervisors, landmen and field supervisors. Warren E&P also employs geologists on a contract basis. As of December 31, 2005, Warren E&P was the operator or co−operator of approximately 85% of the wells in which we and our drilling programs had interests.

Competition

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.

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. Most of our drilling operations require permits or authorizations from federal, state or local agencies, respectively, for both the drilling of the well and the production of the natural gas or oil, as well as the disposal of associated wastes, principally water. Changes in any of these laws and regulations or the denial or vacation of permits 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. We believe 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.

Proposals and proceedings that might affect the oil and gas industry are pending before Congress, the BLM, 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 adverse effect upon our capital expenditures, earnings or competitive position.

Federal Regulation of Sales and Transportation of Natural Gas

Historically, the transportation and sale of natural gas and its component parts 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, including condensate and liquids, 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 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.

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 BLM and the MMS. Federal leases contain relatively standard terms and require compliance with detailed BLM and MMS regulations and orders, which are subject to change. Under certain circumstances, the BLM may require any of our operations on federal leases to be suspended or terminated. Any such suspension or termination could have a material adverse effect on our business, financial condition and results of operations. The MMS issued a final rule that amended its regulations governing the valuation of oil and gas produced from federal leases. This rule, which became effective June 1, 2000, provides that the MMS will collect royalties based on the market value of oil and gas produced from federal leases.

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, 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 requiring 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 relating to water, air, hazardous substances and wastes, and threatened or endangered species 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 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 complied with solid waste regulations in the normal course of business.

In addition to solid and hazardous waste, our production operations generate produced water as a waste material. This water can sometimes be disposed of by discharging it to surface waters or lands under discharge permits issued pursuant to the Clean Water Act, or an equivalent state program. We have obtained surface discharge permits from the Wyoming DEQ for our operations in some areas, such as the Powder River Basin. 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 and exhaust from some of our equipment, such as gas−tired generators and 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 obtained air permits, where needed, in the normal course of business.

Some of our exploration and production activities occur on federal leases. This is particularly true of our CBM operations. Exploration and production operations on federal leases are generally performed in accordance with a record of decision issued by the BLM after preparation of an environmental assessment or an environmental impact statement. 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 CBM operations are subject to records of decision and we have not experienced any material difficulty in complying with their terms and conditions.

In the event 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 prevention, control and countermeasure response plans under the Clean Water Act, or equivalent state regulatory programs. Response costs could be high and may have a material adverse effect on our operations. We may not be fully insured for these costs.

Failure to comply with environmental 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 other 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 we are in compliance with current applicable environmental laws and regulations. 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 that could result in a material adverse effect on our business, financial condition and results of operations. There are no pending or threatened claims for any such environmental cleanup costs, and we operate our producing properties in a prudent manner in order to avoid or minimize liability related to any such claims.

In addition, changes in applicable federal, state and local environmental laws and regulations potentially could have a material adverse effect on our business, financial condition and results of operations. In this regard, our CBM drilling and production operations are subject to ongoing BLM oversight, EIS development and recurring BLM approvals, and could be affected by changes in BLM regulations or policies.

We anticipate that total maximum daily load water quality standards established under Clean Water Act delegated programs may be promulgated for surface water bodies in areas where we operate, including the Powder River Basin. However, we do not expect that any total maximum daily load regulations, or standards promulgated in any area where we operate, will result in a material increase in our produced water disposal costs, as we already inject much of our produced water in disposal wells, rather than discharging into surface water bodies, and would be able to cost−effectively drill and operate additional disposal wells as needed.

We anticipate no material estimated capital expenditures to comply with federal and state environmental requirements. In addition, state−wide reclamation bonds and our $50.0 million casualty and environmental insurance have been adequate to meet the applicable Wyoming bonding and insurance requirements to date. Finally, we have posted a $3.0 million U.S. treasury bond, with a fair value of $2,796,000 as of December 31, 2005, as collateral for a $3.4 million reclamation bond for the Wilmington Townlot Unit.

Coalbed Methane Operations

The majority of our gas production is from CBM operations that generate water discharges and air emissions that are subject to significant regulatory control. Naturally occurring groundwater is produced by our CBM production operations. This produced water is disposed of by re−injection into the subsurface through disposal wells, and 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 state regulatory agencies, and in compliance with applicable, 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 compliance with our permits and applicable federal, state and local laws and regulations without undue cost or burden to our business activities.

Our CBM operations involve the use of gas−fired generators and compressors to transport gas that we produce. Emissions of nitrogen oxides and other combustion by−products from individual or multiple generators and compressors at one location may be great enough to subject the compressors to 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 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 and have not needed to obtain permits relating to particulate matter.

Atlantic Rim

The eastern Washakie Basin is currently the subject of the Atlantic Rim EIS being developed by the BLM under the jurisdiction of the Rawlins, Wyoming regional office. 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 expected during the last half of 2006.

The BLM has issued an interim drilling policy allowing limited CBM drilling and production activity in the Atlantic Rim project 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 and our drilling partners 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 or ancillary facilities. The Atlantic Rim project 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 are subject to the 200 well limit.

The BLM may modify the interim drilling policy at any time and the policy, as with any agency decision, is subject to legal challenges 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. Several of the environmental assessments have been challenged by environmental groups and individuals. In addition, many of the restrictions, conditions and limitations on our drilling, production and construction activities in the Washakie Basin, including without limitation the number of wells that may be drilled and the timing and location for those future wells, will be specified by the BLM in the final Atlantic Rim EIS 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 several years.

Our Washakie Basin CBM production operations are also subject to Wyoming DEQ 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 nine produced water injection wells in the Atlantic Rim project. We will need to obtain permits for additional injection wells, in the event that we need additional subsurface disposal capacity.

Pacific Rim

The western Washakie Basin is currently the subject to the 1997 updated resource management plan, or RMP, under the jurisdiction of the Rock Springs, Wyoming regional office of the BLM. The Rock Springs RMP currently allows the drilling of up to 250 CBM wells that are not contemplated by a separate EIS. In October 2003, at our request, the BLM began the scoping process for an EA that covers approximately 42,721 acres, including the majority of the 35,846 gross (28,191 net) acres comprising our Pacific Rim project area. The Pacific Rim EA contemplates the drilling of 120 CBM wells in the study area. A record of decision on this EA was issued by the BLM in the third quarter of 2004. As has become common after each EA is granted by the BLM, several environmental groups objected to the granting of the EA and sought to prevent the oil and gas owners, including us, from proceeding with drilling. After an appeal by the environmental groups for a State Director Review, the Wyoming State Office affirmed the decision of record for the EA by the BLM and denied the group's request for a stay. Subsequently, the environmental organizations sought a stay from the IBLA. In February 2005, the IBLA issued an order denying the group's petition for a stay. The environmental groups continue to appeal to the IBLA by attacking the granting of the EA's by the BLM, but no further action or decision has been made by the IBLA. However, by issuing its order refusing to grant a stay, the IBLA has allowed our drilling to currently proceed. We were allocated approximately 80 of the 120 wells in the EA study area. We have drilled approximately 24 wells in the Pacific Rim. Upon the completion of the 120 authorized wells, a more comprehensive EIS may be required for additional development in the project. We do not believe that an EIS for the Pacific Rim project will be necessary before late 2006.

Powder River Basin

The Powder River Basin is currently the subject of an EIS that was updated in May 2003. 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 DEQ. The BLM has imposed environmental limitations and conditions on CBM 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 EIS. The BLM may also impose site−specific conditions on development activities, such as drilling and the construction of rights−of−way, before it approves required applications for permits to drill and plans of development. We believe that we have operated our Powder River Basin federal leases in compliance with the BLM's current requirements.

Our Powder River Basin CBM 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 quality 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 Powder River Basin operations. We may need to permit, drill and operate additional injection wells in the event additional subsurface disposal capacity is needed.

Wilmington Field

The Wilmington Townlot Unit and the North Wilmington Unit are 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 water and injection fluids. Remediation and associated costs from a release of produced water or injection fluids in an urban environment could be significant. This potential liability is accentuated by the location of our Wilmington Townlot Unit and North Wilmington Unit leases near 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 either the Wilmington Townlot Unit or North Wilmington Unit.

Operating Hazards And Insurance

The oil and natural gas business involves a variety of operating risks, including fires, explosions, blowouts, environmental hazards, including spills or releases of crude oil, produced water and injection fluids, and other potential events which could have a material adverse effect on our business, financial condition and results of 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, production 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 have a material adverse effect on our business, financial condition and results of operations.

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 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. 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 carrying value of our properties.

Employees

At December 31, 2005, we had 51 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 to perform various professional services, particularly in the areas of geological, permitting and environmental assessment. Independent contractors often perform well drilling and production operations, including pumping, maintenance, dispatching, inspection and testing.

Facilities

Our principal executive offices are located at 489 Fifth Avenue, 32nd Floor, New York, NY 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 Casper, Wyoming occupies 3,750 square feet under a lease currently being negotiated. Our oil and gas administrative office in Long Beach, California occupies 2,206 square feet of space under a lease that was entered into on February 2005, which expires in June 2010. In June 2005, we entered into an office lease in Roswell, New Mexico, which expires in May 2007. We believe that suitable additional space to accommodate our anticipated growth will be available in the future on commercially reasonable terms.

Available Information

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. Our Internet address is www.warrenresources.com.

Glossary of Abbreviations and Terms

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

Adsorption. The attachment, through physical or chemical−bonding, of gas molecules to the coal surface. The adsorbed gas molecules are trapped within the coal, the stability of which is strongly affected by changes in temperature and pressure.

AMI. Area of mutual interest.

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

Bbl/d. One Bbl per day.

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.

Boe. Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.

Btu or British thermal unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Coalbed methane (CBM). Natural gas formed as a byproduct of the coal formation process, which is trapped in coal seams and produced by non−traditional means.

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

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

Desorption. The detachment of adsorbed gas molecules from the coal surface. See “Adsorption’’.

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

Development well. A well drilled into a proved natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.

Dewatering. A coalbed methane well typically begins dewatering with almost all water production and little, or no, natural gas production. The continuous production of water from a well that is dewatering reduces the water reservoir pressure on the coals. The reduced reservoir pressure enables the release of the gas within the coal to the wellbore. This results in an increase in the amount of gas production relative to the amount of water production. Dewatering ceases when peak gas production is reached.

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Environmental assessment (EA). A public document that analyzes a proposed federal action for the possibility of significant environmental impacts. The analysis is required by the National Environmental Policy Act. If the environmental impacts will be significant, the federal agency must then prepare an environmental impact statement.

Environmental impact statement (EIS). A detailed statement of the environmental effects of a proposed action and of alternative actions that is required for all major federal actions.

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.

Exploratory well. A well drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend a known reservoir.

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 farm−in while the interest transferred by the assignor is a farm−out.

Field. An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

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.

Identified drilling locations. Total gross locations specifically identified and scheduled by management as an estimation of our multi−year drilling activities on existing acreage. Our actual drilling activities may change depending on the availability of capital, regulatory approvals, seasonal restrictions, natural gas and oil prices, costs, drilling results and other factors.

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.

Mcf/d. One Mcf per day.

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.

MMBoe. One million barrels of oil equivalent.

MMBtu. Million British thermal units.

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

MMcf/d. One MMcf per day.

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.

MMcfe/d. One MMcfe per day.

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

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

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).

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.

Overpressured. A subsurface formation that exerts an abnormally high formation pressure on a well before it is drilled into.

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

Pod. A grouping of 10 to 24 wells complete with associated infrastructure, including water disposal wells, gathering and compression.

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

Plugging and abandonment. Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.

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%.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved reserves. The estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved undeveloped reserves (PUD). Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Re−entry. Entering an existing well bore to redrill or repair.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.

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;
- storage tanks; and
- gas compression and treatment facilities.

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.

Undeveloped acreage. Lease acreage on which wells have been not drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether such acreage contains proved reserves.

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.

Ultimate recovery. The total expected recovery of oil and gas from a producing well, leasehold, pool or field.

Item 1A: Risk Factors

You should be aware that the occurrence of any of the events described in this Risk Factors section and elsewhere in this annual report or in any other of our filings with the Securities and Exchange Commission ("SEC") could have a material adverse effect on our business, financial position, liquidity and results of operations. In evaluating us, you should consider carefully, among other things, the factors and the specific risks set forth below, and in documents we incorporate by reference. This annual report contains forward−looking statements that involve risks and uncertainties. Some of the following risks relate principally to the industry in which we operate and to our business. Other risks relate principally to the securities markets and ownership of our common shares. If any of the following risks develop into actual events, our business, financial condition or results of operations could be materially adversely affected, the trading price of your shares could decline, and you may lose all or part of your investment.

Risks Relating to Our Business

Our reserve estimates depend on many assumptions that may turn out to be inconclusive, subject to varying interpretations or inaccurate.

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, the 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 prospectus. A reduction in natural gas and oil prices, for example, would reduce the value of proved reserves and 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, 2005, approximately 91% 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. We have prepared estimates of our natural gas and oil reserves and the costs associated with these reserves in accordance with industry standards. However, the estimated costs may not be accurate, development may not occur as scheduled, or the actual results may not be as estimated. We may not have or be able to obtain the capital we need to develop these proved reserves.

You should not assume that the present value of future net revenues referred to in this annual report 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 the 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.

Failure to obtain financing and environmental approvals for the development of our Washakie Basin properties in which we own interests could have a material adverse effect on our business, financial condition or results of operations.

Our future growth plans rely heavily on establishing significant production and reserves in the Washakie Basin. However, an inability to provide or 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 U.S. Bureau of Land Management, or BLM, has begun preparation of an environmental impact statement, or 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 that will, without limitation, establish the number of wells that may be drilled in the Atlantic Rim and the timing and location of those wells. The EIS is currently expected to be completed by the second half of 2006, although this projected completion date may be extended. Our prior drilling in this basin, along with our projected drilling through 2006, 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 and our drilling partners. If public opposition to continued drilling in this basin or other regulatory complications occur, the EIS may not be completed during 2006, or could cause the BLM to condition, severely restrict or prohibit drilling on a more permanent basis. Legal challenges to the EIS could also materially affect the timing and ultimate environmental restrictions that are imposed on our drilling and production operations. Additionally, in the Pacific Rim a record of decision on an EA was granted in the third−quarter of 2004 by the BLM allowing the drilling of up to 120 wells. As has become common after each EA is granted by the BLM, several environmental groups objected to the granting of the EA and sought to prevent the oil and gas owners, including us, from proceeding with drilling. After an appeal by the environmental groups for a State Director Review, the Wyoming State Office affirmed the decision of record for the EA by the BLM and denied the group’s request for a stay. Subsequently, the environmental organizations sought a stay from the IBLA. In February 2005, the IBLA issued an order denying the group’s petition for a stay. The environmental groups continue to appeal to the IBLA by attacking the granting of the EA’s by the BLM, but no further action or decision has been made by the IBLA. However, by issuing its order refusing to grant a stay, the IBLA has allowed our drilling to currently proceed. We were allocated approximately 80 of the 120 wells in the EA study area. We have drilled approximately 24 wells in the Pacific Rim. Upon the completion of the 120 authorized wells, a more comprehensive EIS may be required for additional development in the project. We do not believe that a full EIS for the Pacific Rim project will be necessary before late 2006.

Any or all of these contingencies 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 timing or outcome of the Atlantic EIS.

Conditions, delays or restrictions imposed on the drilling or the management of groundwater produced during drilling could severely limit our operations there or make them uneconomic. Any unfavorable developments in the Washakie Basin could impede our growth, as we intend to undertake significant activity in order to increase our production and reserves in this area. See "Business and Properties—Environmental Matters".

Our substantial contingent obligations to repurchase drilling program interests could strain our financial resources.

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 these repurchases. These repurchase obligations could put a strain upon our financial resources and otherwise adversely affect our ability to execute our business plan. Any payment made under this obligation would be recorded as a reduction to minority interest as shown on our balance sheet.

Under the terms of our seven drilling programs formed between 1998 and 2001 investors have the right to require us to repurchase their interests in each program seven to 25 years from the date of a partnership's formation, to the extent that the drilling programs and other program investors elect not to purchase the investor's interest. The price of our repurchase is fixed by the drilling program agreement to be the lower of the PV−10 value of the assets of the program and a formula based on the amount of the investor's cash investment reduced by the amount of any cash distributions received. As of December 31, 2005, based on the December 31, 2005 reserve reports of the respective drilling programs, the aggregate PV−10 value of the assets in these programs was $45.0 million. Because this amount is less than the formula price of $90.7 million as of December 31, 2005, the PV−10 of $45.0 million is our maximum repurchase obligation as of December 31, 2005. This PV−10 amount may increase when we drill the remaining 3 net wells or place the remaining 54 net wells on production on behalf of these seven drilling programs.

Based on the formula price as of December 31, 2005, if in the future the drilling program PV−10 value were to exceed $90.7 million, then our maximum obligation would be the formula price of $90.7 million, consisting of obligations of $41.9 million between January 1, 2006 and December 31, 2008, $47.7 million between January 1, 2009 and December 31, 2010 and $1.1 million thereafter.

We face significantly increasing water disposal costs in our CBM drilling operations.

The Wyoming Department of Environmental Quality, or Wyoming DEQ, has restrictive regulations applying to the surface disposal of water produced from our CBM drilling operations. We typically obtain Clean Water Act, Safe Drinking Water Act and analogous state and local permits to use surface discharge methods, such as settling ponds, 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. Injection wells are regulated by the Wyoming DEQ and the Wyoming Oil & Gas Conservation Commission, and permits to drill these wells are obtained from these agencies. Based on our experience with CBM 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 difficult to obtain. In Wyoming, our produced water is currently injected at six 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 increase significantly, which could have a material adverse effect on our business, financial condition and results of operations.

Operational impediments may hinder our access to natural gas and oil markets or delay our production.

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 CBM operations where this infrastructure is less developed than in our traditional oil and gas operations. For example, there is limited pipeline capacity in the southern portion of the Washakie Basin. Therefore, if drilling results are positive in the entire length of the Washakie Basin, a new pipeline would need to be built at a cost of approximately $25 million, our portion of which would be approximately $12.5 million.

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; and
- federal and state transportation, tax and energy policies.

In 2003, we entered into an agreement with Anadarko to jointly construct compression facilities and a pipeline in the Washakie Basin. Any significant change in our arrangement with Anadarko or other market factors affecting our overall infrastructure facilities could adversely impact our ability to deliver the natural gas we produce to market in an efficient manner, or its price. 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. If that were to occur, we would be unable to realize revenue from those wells until arrangements were made to deliver our production to market.

We may incur additional debt in order to fund our exploration and development activities, which would reduce our financial flexibility and could have a material adverse effect on our business, financial condition or results of operations.

We may incur additional debt in order to make future acquisitions or develop our properties. A higher level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and reduce our level of indebtedness depends on future performance. General economic conditions, oil and gas prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control. We may not be able to generate sufficient cash flow to pay the interest on our debt or pay our debt at maturity. In addition, 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 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. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results.

We have substantial capital requirements that, if not met, may hinder our growth and operations.

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 $108.1 million in 2006. Historically, we have financed our capital expenditures primarily through drilling programs that participated in the exploration, drilling and development of the projects, and to a lesser extent through debt and equity financing. In the future, we intend to finance these capital expenditures through the proceeds from our initial and follow−on public offerings, debt placements and from 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 CBM projects in the Washakie Basin;
- the success of our waterflood recovery oil projects in the Wilmington field;
- 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. Additional 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.

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 business, financial condition and results of operations.

We have incurred losses from operations in the past and cannot guarantee profitability in the future.

At December 31, 2005, we had an accumulated deficit of $82.9 million and total stockholders’ equity of $278.0 million. We have recognized annual net losses in each year since 2000. See “Selected Consolidated Financial Data”. We may not achieve or sustain profitability or positive cash flows from operating activities in the future.

Properties that we buy may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against them, which could cause us to incur losses.

One of our growth strategies is to pursue selective acquisitions of natural gas and oil reserves. We perform a review of the target properties that we believe is consistent with industry practices. However, these reviews are inherently incomplete. It generally is not feasible to review in depth every individual property involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, a seller may be unwilling or unable to provide effective contractual protection against all or part of those problems, and we often assume environmental and other risks and liabilities in connection with the acquired properties.

Our operations in Wyoming could be adversely affected by abnormally poor weather conditions.

Our operations in Wyoming 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 business, 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 nine limited partnerships and participate in two 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 have a material adverse effect on our business, financial condition and results of operations. See "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 our best interests or the best interests of our stockholders.

Our role as general partner of limited partnerships and co−venturer in joint ventures may result in conflicts of interest between the interests of those entities and our stockholders. For example, we plan to continue drilling natural gas and oil wells for 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. Any 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, Timothy A. Larkin, our executive vice president and chief financial officer, and Kenneth A. Gobble, our senior vice president of exploration and production, and other key management and technical personnel. The loss of the services of Messrs. Swanton, Larkin, Gobble or other key management and technical personnel could adversely affect our business operations. We maintain key person life insurance on Messrs. Swanton, Larkin and Gobble 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.

We do not insure against all potential operating risks. We may incur substantial losses and be subject to substantial liability claims as a result of our natural gas and oil operations.

We are not insured against all risks. We ordinarily maintain insurance against various losses and liabilities arising from our operations in accordance with customary industry practices and in amounts that management believe to be prudent. Losses and liabilities arising from uninsured and underinsured events or in amounts in excess of existing insurance coverage could have a material adverse effect on our business, financial condition or results of operations. Our natural gas and oil exploration and production activities are subject to hazards and risks associated with drilling for, producing and transporting natural gas and oil, and any of these risks can cause substantial losses resulting from:

- environmental hazards, such as uncontrollable flows of natural gas, oil, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse;
- fires and explosions;
- personal injuries and death;
- regulatory investigations and penalties; and
- natural disasters.

Any of these risks could have a material adverse effect on our ability to conduct operations or result in substantial losses to us. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could have a material adverse effect on our business, financial condition and results of operations. See “Business and Properties—Operating Hazards And Insurance”.

We have limited control over activities on properties we do not operate, which could reduce our production and revenues.

Substantially all of our business activities are conducted through joint operating agreements under which we own partial interests in natural gas and oil properties. We do not operate all of the properties in which we have an interest and in many cases we do not have the ability to remove the operator in the event of poor performance. As a result, we have a limited ability to exercise influence over normal operating procedures, expenditures or future development of underlying properties and their associated costs. The failure of an operator of our wells to adequately perform operations, or an operator’s breach of the applicable agreements, could reduce our revenues and production. The success and timing of our drilling and development activities on properties operated by others therefore depends upon a number of factors outside of our and the operator’s control, including:

- timing and amount of capital expenditures;
- expertise and financial resources;
- inclusion of other participants in drilling wells; and
- use of technology.

Defects in the title to any of our natural gas and oil interests could result in the loss of some of our natural gas and oil 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 Townlot Unit in 1999 and 2005 with no title opinion as to the interests acquired in the Wilmington Townlot Unit, which may ultimately prove to be less than the interests we believe we own. The prior owner had acquired its interests from a third party that in turn had acquired its interest from Exxon Corporation with no warranty of title. Exxon had owned the Wilmington Townlot Unit for over 25 years before its sale in 1997. Similarly, when we acquired our interest in the North Wilmington Unit in December 2005, we acquired no title opinion as to the interests we own in the North Wilmington Unit. The prior owner had owned the North Wilmington Unit for over 15 years, acquired the North Wilmington Unit from Sun Oil Corporation with warranty of title, which had owned unit for over 20 years before its sale in 1990. Losses in the Wilmington Townlot Unit and North Wilmington Units may result from title defects or from ownership of a lesser interest than we believe we acquired. 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.

Risks Relating to the Oil and Gas Industry

A substantial or extended decline in natural gas and oil prices may adversely affect our ability to meet our capital expenditure obligations and financial commitments.

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 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.

Among the factors that cause this fluctuation are:

- changes in domestic and global supply and demand for natural gas and oil;
- levels of production and other activities of the Organization of Petroleum Exporting Countries and other natural gas and oil producing nations;
- market expectations about future prices;
- the level of global natural gas and oil exploration, production activity and inventories;
- political conditions, including embargoes, in or affecting other oil producing activity; and
- the price and availability of alternative fuels.

Lower natural gas and oil prices may not only decrease our revenues on a per unit basis, but also may reduce the amount of natural gas and oil we can produce economically. A substantial or extended decline in natural gas and oil prices may have a material adverse effect on our business, financial condition and results of operations.

Drilling for and producing natural gas and oil are high risk activities with many uncertainties that could have a material adverse effect on our business, financial condition or results of operations.

Our future success depends largely on the success of our exploitation, exploration, development and production activities. These activities are subject to numerous risks beyond our control, including the risk that we will not find any commercially productive natural gas or oil reservoirs. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data, and engineering studies, the results of which are often inconclusive or subject to varying interpretations. See "—Risks Related to Our Business—Our reserve estimates depend on many assumptions that may turn out to be inconclusive, subject to varying interpretations or inaccurate" for a discussion of the uncertainty involved in these processes. Our cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or prevent drilling operations, including:

- Delays in obtaining drilling permits from applicable regulatory authorities
- unexpected drilling conditions;
- pressure or irregularities in geological formations;
- equipment failures or accidents;
- well blow−outs;
- fires and explosions;
- pipeline and processing interruptions or unavailability;
- title problems;
- adverse weather conditions;
- lack of market demand for natural gas and oil;
- delays imposed by or resulting from compliance with environmental and other regulatory requirements;
- shortages of or delays in the availability of drilling rigs and the delivery of equipment; and
- reductions in natural gas and oil prices.

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 contracts covering our lease rights in potential drilling locations. We cannot be sure that we will ever drill our identified potential drilling locations 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.

If natural gas and oil prices decrease, we may be required to record an impairment, which would reduce our stockholders' equity.

We use the successful efforts method of accounting for costs related to our natural gas and oil properties. Accordingly, we capitalize the cost to acquire, explore for and develop gas and oil properties. Wells are evaluated on a field−by−field basis for impairment. We review our natural gas and oil properties on a field level 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 which does not impact cash flow from operating activities, but does reduce our stockholders' equity. The risk that we will be required to write down the carrying value of our oil and gas properties increases when oil and gas prices are low or volatile. In addition, write−downs may occur if we experience substantial downward adjustments to our estimated proved reserves. Once incurred, a write−down of oil and gas properties is not reversible at a later date. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies" for additional information on these matters.

Competition in the oil and gas industry is intense, and many of our competitors have greater financial, technological and other resources than we do, which may adversely affect our ability to compete.

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 have a material adverse effect on the cost, manner or feasibility of doing business.

Exploration for and the 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 and environmental laws and regulations, and requires various permits and approvals from federal, state and local agencies. If these permits are not issued or unfavorable restrictions or conditions are imposed on our drilling activities, we may not be able to conduct our operations as planned. Alternatively, failure to comply with these laws and regulations, including the requirements of any permits, 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 and California regions, 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. For example, matters subject to regulation and the types of permits required include:

- water discharge and disposal permits for drilling operations;
- drilling permits;
- drilling bonds;
- reclamation;
- spacing of wells;
- occupational safety and health;
- unitization and pooling of properties;
- air quality, noise levels and related permits;
- rights−of−way and easements;
- reports concerning operations to regulatory authorities;
- calculation and payment of royalties;
- gathering, transportation and marketing of gas and oil;
- taxation; and
- waste disposal.

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

- personal injuries;
- property damage;
- oil spills;
- discharge of hazardous materials;
- well reclamation costs;
- surface remediation and clean−up costs;
- fines and penalties;
- natural resource damages; and
- other environmental protection and damages issues.

See “Business and Properties—Regulations” for a more detailed discussion of laws affecting our operations.

Shortages of rigs, equipment, supplies and personnel could delay or otherwise adversely affect our cost of operations or our ability to operate according to our business plans.

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. As a result, the costs and delivery times of rigs, equipment and personnel could be substantially greater than in previous years. From time to time, including the present, these costs have sharply increased and could do so again. For example, throughout 2005, as energy prices increased significantly, we experienced higher costs for drilling rigs, equipment and personnel. 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.

Unless we replace, maintain or expand our natural gas and oil reserves, our reserves and production will decline, which could have a material adverse effect on our business, financial condition and results of operations.

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 exploitation, 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.

Risks Relating to Ownership of Our Common Stock

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

Sales of substantial amounts of previously restricted shares of our common stock in the public market, or the perception that these sales may occur, could cause the market price of our common stock to decline, or could impair our ability to raise capital through the sale of additional common or preferred stock.

As of December 31, 2005, we had 52,738,384 shares of common stock outstanding, 756,576 shares of common stock were issuable upon conversion of our convertible debt and convertible preferred stock and 5,478,830 shares of common stock were issuable upon exercise of outstanding options and warrants. Also, all of our directors and executive officers, holding approximately 7 % of the outstanding shares of our common stock, are subject to agreements with our secondary public offering underwriters or us that restrict their ability to sell or transfer their stock until March 19, 2006.

In accordance with the terms and conditions of the registration rights agreement dated December 12, 2002, holders of at least a 50% majority of our 652,336 shares of convertible preferred stock as of December 31, 2005 have a one−time right, to demand that their shares of common stock issuable upon conversion of the convertible preferred stock be registered under the Securities Act. Also, these holders may have the right to include their shares of common stock, subject to the consent of any underwriter, in registration statements that we may file, if any, to register shares of our common stock under the Securities Act for ourselves or other stockholders.

If our stockholders sell significant amounts of common stock in any public market that 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 stock price may be volatile, and your investment in our stock could decline in value.

In recent years, the stock market has experienced significant price and volume fluctuations. Our common stock may also experience volatility unrelated to our own operating performance for reasons that include:

- domestic and worldwide supplies and prices of and demand for natural gas and oil;
- political conditions in natural gas and oil producing regions;
- war and acts of terrorism;
- demand for our common stock;
- revenue and operating results failing to meet the expectations of securities analysts or investors in any particular quarter;
- changes in expectations as to our future financial performance or changes in financial estimates, if any, of public market analysts;
- investor perception of our industry or our prospects;
- general economic trends;
- limited trading volume of our stock;
- changes in environmental and other governmental regulations;
- actual or anticipated quarterly variations in our operating results;
- our involvement in litigation;
- conditions generally affecting the oil and natural gas industry;
- the prices of oil and natural gas;
- announcements relating to our business or the business of our competitors;
- our liquidity; and
- our ability to obtain or raise additional funds.

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

As of March 7, 2006, our executive officers and directors beneficially owned approximately 7% of our 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.

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Provisions in our articles of incorporation, bylaws and Maryland law may make it more difficult to effect a change in control, which could adversely affect the price of our common stock.

Provisions of our articles of incorporation, bylaws and Maryland law could make it more difficult for a third party to acquire us, even if doing so would be beneficial to our stockholders. We may issue shares of preferred stock in the future without stockholder approval and upon such terms as our board of directors may determine. Our issuance of this preferred stock could have the effect of making it more difficult for a third party to acquire, or of discouraging a third party from acquiring, a majority of our outstanding stock and potentially prevent the payment of a premium to stockholders in an acquisition.

Our articles of incorporation and bylaws contain provisions that could delay, defer or prevent a change in control of us or our management. These provisions include:

- giving the board the exclusive right to fill all board vacancies;
- providing that special meetings of stockholders may only be called by the board pursuant to a resolution adopted by
  - — a majority of the board, either upon a motion or upon written request by holders of at least 66⅔% of the voting power of the shares entitled to vote, or
  - — by our president;
- a classified board of directors;
- permitting removal of directors only for cause and with a super−majority vote of the stockholders; and
- prohibiting cumulative voting in the election of directors.

These provisions also could discourage proxy contests and make it more difficult for our stockholders to elect directors and take other corporate actions. As a result, these provisions could make it more difficult for a third party to acquire us, even if doing so would benefit our stockholders, and may limit the price that investors are willing to pay in the future for shares of our common stock.

We are also subject to provisions of the Maryland General Corporation Law that prohibit business combinations with persons owning 10% or more of the voting shares of a corporation's outstanding stock, unless the combination is approved by the board of directors prior to the person owning 10% or more of the stock, for a period of five years, after which the business combination would be subject to special stockholder approval requirements. This provision could deprive our stockholders of an opportunity to receive a premium for their common stock as part of a sale of our company, or may otherwise discourage a potential acquirer from attempting to obtain control from us, which in turn could have a material adverse effect on the market price of our common stock. See "Description of Capital Stock".

We have not paid cash dividends on our common stock and do not anticipate paying any dividends on our common stock in the foreseeable future.

Under the terms of our convertible preferred stock, we may not pay dividends on our common stock unless all accrued dividends on our convertible preferred stock have been paid. We anticipate that we will retain all future earnings and other cash resources for the future operation and development of our business. Accordingly, we do not intend to declare or pay any cash dividends on our common stock in the foreseeable future. Payment of any future dividends will be at the discretion of our board of directors after taking into account many factors, including our operating results, financial conditions, current and anticipated cash needs and plans for expansion.

Item 1B: Unresolved Staff Comments.

None.

Item 3: Legal Proceedings

Gotham Insurance Company v. Warren. In 1998, the Company and its subsidiary, Warren E&P, Inc., were 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. 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 and other underwriters. The insurers paid approximately $1.8 million under the insurance policy and Gotham has sought a refund of approximately $1.8 million, is 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 in favor of Warren E&P on essentially all claims except its bad faith claims against Gotham, and Gotham's claims were rejected. Final judgment was rendered by the District Court on May 14, 2001 in Warren E&P's favor for the remaining policy proceeds, interest and attorneys' fees. Gotham appealed the final judgment to the San Antonio Court of Appeals, seeking a refund of approximately $1.5 million. On July 23, 2003, the San Antonio Court of Appeals reversed, in Gotham's favor, the trial court's earlier summary judgment for Warren E&P and remanded the case to the trial court for further proceedings consistent with the San Antonio Court of Appeals' decision. A hearing was held on December 17, 2004 to consider the parties' motions to determine both the amount of actual loss incurred by Gotham, the amount of judgment liability to be paid by Warren and Warren E&P and Warren's other claims against Gotham that were pending but unheard by the District Court as a result of the District Court's granting a summary judgment in Warren E&P's favor in May 2001. On January 4, 2005, the Company received an order of the trial court that Warren and Warren E&P were obligated to repay Gotham $1.8 million, along with attorneys' fees and statutory interest estimated at $966,000. At December 31, 2004, Warren recorded a provision for $1.8 million relating to this judgement. On April 11, 2005, Warren filed to appeal the order of the trial court to the Texas Court of Appeals. In connection with the appeal, on April 14, 2005 Warren posted a supersedeas bond with the Court of Appeals in the amount of $2.9 million to cover the trial court judgment plus potential legal fees, court costs and statutory interest for the next two years. The supersedeas bond was secured by a collateral pledge of U.S. Treasury securities owned by Warren in the amount of $2.9 million, which is booked in Other Assets on the Balance Sheet. All briefings before the Court of Appeals have been completed and oral arguments were made on February 1, 2006. We are awaiting the decision of the Court of Appeals. Although the Company believes that it has meritorious grounds for the appeal, if its appeal is unsuccessful, it will be obligated to pay the restitution to Gotham as ordered by the trial court.

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 2005.

PART II

Item 5: Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market Information.

The Company conducted its initial public offering on December 16, 2004 at $7.50 per share of common stock. Our common stock has traded on the Nasdaq National Market under the symbol "WRES" since December 17, 2004. The following table sets forth, for the period indicated, the high and low sales prices for our common stock as reported by the Nasdaq National Market:

	Common Stock Price	
	High	Low
December 17 thru December 31, 2004	$ 10.00	$ 8.00
Quarter ended March 31, 2005	13.00	8.30
Quarter ended June 30, 2005	11.41	8.01
Quarter ended September 30, 2005	17.45	10.10
Quarter ended December 31, 2005	18.19	13.00

On March 7, 2006, the closing sales price for our common stock as reported by Nasdaq was $14.04 per share.

Holders

As of March 7, 2006, there were approximately 3,411 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.

Securities Authorized for Issuance Under Compensation Plans

The table below includes information about our equity compensation plans as of December 31, 2005:

	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	379,000	$ 7.57	1,596,000
2001 Stock Incentive Plan	2,500,000	814,971	$ 8.46	555,988
2001 Key Employee Stock Incentive Plan	2,500,000	1,316,750	$ 6.37	1,183,250
Total	6,975,000	2,510,721	$ 7.23	3,335,238

As a result of job performance, during 2005 the Compensation Committee elected to accelerate the vesting of certain unvested stock options previously awarded to employees, officers and directors of the Company under various stock option plans was accelerated. As a result of this action, options to purchase approximately 1.0 million shares of our common stock that would otherwise have vested over the next two years became fully vested.

Issuer Purchases of Equity Securities

The Company did not repurchase any of its equity securities in 2005.

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 annual report. The selected financial data as of December 31, 2005, 2004, 2003, 2002 and 2001 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.

	Year ended December 31,				
	2005	2004	2003	2002	2001
Consolidated Statement of Operations Data:					
Revenues:					
Oil & gas sales	$ 13,959	$ 6,454	$ 5,717	$ 593	$ 948
Turnkey contracts with affiliated partnerships	9,756	10,530	11,301	5,841	30,103
Oil & gas sales from marketing activities	10,211	6,171	5,621	11,272	14,867
Well services	1,555	1,070	1,168	1,895	5,574
Total revenues	35,481	24,225	23,807	19,601	51,492
Costs and operating expenses:					
Production and exploration	7,296	3,935	3,812	1,326	568
Turnkey contracts	11,275	12,932	7,285	4,965	25,953
Cost of oil and gas purchased from affiliated partnerships	10,079	6,028	5,500	11,121	15,299
Well services	1,147	673	662	839	3,519
Depreciation, depletion, amortization and impairment	3,553	4,023	3,249	9,930	14,462
Contingent repurchase obligation	—	—	—	(3,065)	3,319
General and administrative	7,476	8,116	4,496	6,278	5,485
Retirement of debt expense	1,862	—	—	—	—
Total costs and operating expenses	42,688	35,707	25,004	31,394	68,605
Loss from operations	(7,207)	(11,482)	(1,197)	(11,793)	(17,113)
Other income (expense):					
Interest and other income	3,302	2,089	1,340	5,258	1,977
Interest expense	(1,761)	(494)	(1,528)	(6,313)	(5,776)
Gain on sale of oil and gas properties	203	120	494	4,287	—
Net gain (loss) on investment	961	(43)	21	464	(10)
Total other income (expense)	2,705	1,672	327	3,696	(3,809)
Loss before income taxes, minority interest and change in accounting principle	(4,502)	(9,810)	(870)	(8,097)	(20,922)
Income tax expense (benefit)	391	(59)	129	(471)	152
Loss before minority interest and cumulative change in accounting principle	(4,893)	(9,751)	(999)	(7,626)	(21,074)
Minority interest	(279)	(209)	(112)	—	—
Net loss before change in accounting principle	(5,172)	(9,960)	(1,111)	(7,626)	(21,074)

Cumulative effect of change in accounting principle	—	—	(88)	—	—
Net loss	(5,172)	(9,960)	(1,199)	(7,626)	(21,074)
Preferred dividends and accretion	3,774	6,591	4,562	16	—
Net loss applicable to common stockholders	$ (8,946)	$ (16,551)	$ (5,761)	$ (7,642)	$ (21,074)
Basic and diluted loss per common share	$ (0.23)	$ (0.84)	$ (0.34)	$ (0.44)	$ (1.20)
Weighted average shares outstanding basic and diluted	39,177,816	19,739,048	16,827,857	17,339,869	17,532,882
Consolidated Statement of Cash Flows Data:					
Net cash provided by (used in):					
Operating activities	$ (10,348)	$ (4,507)	$ 5,278	$ (6,101)	$ (15,712)
Investing activities	(54,654)	(29,033)	(13,524)	5,317	(17,635)
Financing activities	79,714	108,931	9,591	1,045	(2,700)

	As of December 31,				
	2005	2004	2003	2002	2001
Balance Sheet Data:					
Cash and cash equivalents	$ 114,632	$ 99,921	$ 24,529	$ 23,184	$ 22,924
Total assets	320,764	246,911	151,054	108,262	94,900
Total long−term debt (including current maturities)	8,906	50,038	49,916	56,202	61,880
Stockholders’ equity (deficit)	278,040	157,569	56,394	7,002	(6,434)

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

The discussion and analysis that follows should be read together with the “Selected Consolidated Financial Data” and the accompanying financial statements and notes related thereto that are included elsewhere in this annual report. It includes forward−looking statements that may reflect our estimates, beliefs, plans and expected performance. The forward−looking statements are based upon events, risks and uncertainties that may be outside our control. Our actual results could differ significantly from those discussed in these forward−looking statements. Factors that could cause or contribute to these differences include but are not limited to, market prices for natural gas and oil, regulatory changes, estimates of proved reserves, economic conditions, competitive conditions, development success rates, capital expenditures and other uncertainties, as well as those factors discussed below and elsewhere in this annual report, including in “Risk Factors” and “Cautionary Note Regarding Forward−Looking Statements”, all of which are difficult to predict. As a result of these assumptions, risks and uncertainties, the forward−looking matters discussed may not occur.

Overview

We are a growing independent energy company engaged in the exploration and development of domestic onshore natural gas and oil reserves. We focus our efforts primarily on the exploration and development of coalbed methane, or CBM, properties located in the Rocky Mountain region and on our waterflood oil recovery programs in the Wilmington field within the Los Angeles Basin of California. As of December 31, 2005, we owned natural gas and oil leasehold interests in approximately 277,001 gross (154,100 net) acres, 93% of which are undeveloped. Substantially all our undeveloped acreage is located in the Rocky Mountains. Our total net proved reserves are located on less than 10% of our net acreage.

From our inception in 1990 through 2003, we functioned principally as the sponsor of privately placed drilling programs and joint ventures. Under these programs, we contribute drilling locations, pay tangible drilling costs and provide turnkey drilling services, natural gas marketing services and well services to the drilling partnerships and retain an interest in the wells. Historically, a substantial portion of our revenue was attributable to these turnkey drilling services.

From December 2002 to March 2003, 13 drilling programs formed from 1994 though 1997 converted from Delaware limited partnerships to Delaware limited liability companies. As a result of these conversions, we issued an aggregate of 3,341,559 restricted convertible preferred shares to the 13 LLCs as additional capital contributions and received as consideration additional standard membership interests in the LLCs. This increased our pro rata beneficial interests in the oil and gas wells owned by the LLCs. Also during 2003, we issued an aggregate of 1,048,336 restricted convertible preferred shares to two joint ventures as additional capital contributions and received as consideration additional joint venture interests in the joint ventures, which increased our pro rata beneficial interests in the oil and gas wells owned by the joint ventures.

We anticipate that revenue from turnkey drilling services will become increasingly less material to our business in the future. Our future revenue growth is primarily dependent on our ability to increase our oil and gas reserves and production. We plan to participate in all our Wyoming drilling activities on a pro rata basis with our drilling programs until we have performed our obligations under the turnkey drilling contracts related to our existing deferred income of approximately $1.8 million as of December 31, 2005. After we have performed our obligations under the turnkey drilling contracts we intend to invest more of our own capital in drilling operations in order to accelerate the growth of our production and reserves. We also anticipate that any future drilling activities that we undertake with third parties will be through joint ventures and similar arrangements.

The schedule below reflects revenue and expense from gas and oil sales and from turnkey contracts for the years ended December 31, 2005 and 2004.

	2005	2004
Oil and gas sales	$13,959,097	$ 6,454,334
Production and exploration expense	7,295,520	3,935,137
Depreciation, depletion, amortization and impairment	3,372,084	3,840,781
Gross margin	$ 3,291,493	$ (1,321,584)
Turnkey contract revenue with affiliated partnerships	$ 9,756,209	$10,529,883
Turnkey contract expense	11,275,348	12,932,124
Depreciation, depletion, amortization and impairment	103,216	103,216
Gross margin	$ (1,622,355)	$ (2,505,457)

We estimate that the completion of drilling activities on behalf of our drilling programs and the subsequent commencement of drilling activities primarily for our own account will occur in 2006. We anticipate that, depending upon our drilling results, our production revenue may not be sufficient for us to achieve positive cash flow from operating activities on or before the end of 2006. Even if we are able to achieve positive cash flow from operating activities on or before the end of 2006, which we cannot assume, we may not be able to achieve positive cash flow from operating activities on a cumulative basis for 2006. To the extent we are able to achieve increases in natural gas and oil production revenue, we also will experience increases in production and exploration expense.

Liquidity and Capital Resources

During December 2005, we sold 6.9 million shares in a secondary offering raising net proceeds of $95.0 million. During the first eleven months of 2004, we raised $41.8 million from private sales of our common stock and warrants, and through the exercise of stock options. During December 2004, we sold 10.9 million shares of common stock in an initial public offering raising net proceeds of $76.2 million.

Our cash and cash equivalents increased $14.7 million during 2005. This resulted from an increase in cash flows provided by financing activities of $79.7 million. This was offset by a decrease in cash used in investing activities of $54.7 million and a decrease in cash used in operating activities of $10.3 million.

Currently our assets are unencumbered, except for restricted investments in US Treasury Bonds. As a result the Company may seek to obtain bank financing to fund future activities.

Cash provided by financing activities of $79.7 million results from a secondary offering raising net proceeds of $95.0 million as mentioned above. This increase in cash was offset by the early redemption of certain debentures for cash totaling $19.8 million and dividends paid on preferred stock totaling $1.6 million. During 2005, we reduced our outstanding debenture balance from $46.5 million to $2.6 million by either converting the debentures into common stock or by redeeming the debentures for cash. Cash used in investing activities of $54.7 million results from $71.6 million for expenditures on oil and gas properties offset by the release of $16.9 million in U.S. Treasury Bonds relating to the redemption of debentures discussed above. Cash used in operating activities of $10.3 million primarily relates to drilling wells on behalf of our drilling programs and oil and gas operations.

Another commitment of funds relates to the drilling programs. Our deferred revenue balance relating to our drilling commitments totaled $1.8 million at December 31, 2005. This commitment approximates 4 net wells, primarily in the Washakie Basin, to be drilled on behalf of our drilling programs formed in 2003 and prior.

The Company had a net loss before dividends of $5.2 million for 2005, as compared to a net loss before dividends of $10.0 million for 2004. At December 31, 2005, current assets exceeded current liabilities by approximately $93.8 million. During the second quarter of 2005, the Company and the preferred holders agreed by greater than the requisite 66.67% majority that a dividend be paid in kind with Warren Resources common stock for the accrued dividend for the quarters ended March 31 and June 30, 2005, amounting to approximately $3.3 million. Accordingly, Warren issued total of 315,867 shares of its common stock as a dividend. Accrued dividends as of December 31, 2005 were approximately $0.4 million.

2006 Capital Expenditure Program

Our capital expenditure budget for 2006 is $108 million, which includes participation in the drilling of 158 gross (124.7 net) wells. At the present time, we are concentrating our drilling activities in California and Wyoming. We have two California projects in the Wilmington field, the Wilmington Townlot Unit (WTU) and the North Wilimington Unit (NWU). Additionally, we have three projects in Wyoming, the Atlantic Rim and Pacific Rim projects in the Washakie Basin and an exploratory project. We are planning to drill 94 gross (92.9 net) producing and injecting wells in California with capital expenditures estimated at $70.9 million. We plan to drill 72 gross (70.9 net) wells in the WTU with estimated capital expenditures of $60.9 million. We plan to recomplete or drill 22 gross (22.0 net) wells in the NWU with estimated capital expenditures of $10.0 million. Also, we plan to drill 64 producing and injecting wells in Wyoming with estimated capital expenditures of $37.2 million. We plan to drill 52 gross (23.9 net) wells in the Atlantic Rim project with estimated capital expenditures of $21.6 million. We plan to drill 11 gross (6.9 net) wells in the Pacific Rim project with estimated capital expenditures of $11.3 million. Lastly, we plan on drilling one exploratory well in Wyoming with estimated capital expenditures of $4.3 million. The final determination regarding whether to drill the budgeted wells referred to above is dependent upon many factors including:

- the availability of sufficient capital resources;

- the ability to acquire proper governmental permits and approvals; and
- economic and industry conditions at the time of drilling such as prevailing and anticipated energy prices and the availability of drilling equipment.

Our estimated total proved reserves as of December 31, 2005 are approximately 326.9 billion cubic feet of gas equivalent (Bcfe) with a PV−10 value of approximately $637.9 million using December 31, 2005 oil and gas pricing. Approximately 91% of our estimated net proved reserves are undeveloped.

Compared with the development of our CBM properties, we anticipate that development of our oil properties in California could have a more immediate impact on our cash flows. We also anticipate that we will be able to conduct drilling operations in California on a year−round basis without weather−induced or other drilling delays as may occur in the Rocky Mountain areas where our CBM properties are located.

A substantial portion of our economic success depends on factors over which we have no control, including natural gas and oil prices, operating costs, and environmental and other regulatory matters. In our planning process, we focus on maintaining financial flexibility together with a low cost structure in order to reduce our vulnerability to these uncontrollable factors.

Stock based Equity Compensation Plan Information

At December 31, 2005, we had approximately 2.5 million vested outstanding stock options issued under our stock based equity compensation plans. Of the total 2.5 million outstanding vested options, all had exercise prices below the closing market price ($15.82) of our common stock on December 31, 2005. If such options are exercised by the holders, we will receive the exercise price in cash. The following table provides information with respect to shares of our common stock that may be issued under vested stock options whose exercise price was less than our closing stock price on December 31, 2005.

Exercise Price of Outstanding Vested Options	Number of Securities to be Issued Upon Exercise of Vested Outstanding Options	Proceeds to be Received Upon Exercise of Vested Outstanding Options
$4.00	766,772	$ 3,067,088
$7.00	632,500	4,427,500
$9.05	697,500	6,312,375
$10.00	363,949	3,639,490
$11.00	10,000	110,000
$14.85	40,000	594,000
	2,510,721	$ 18,150,453

For additional detail about our stock based equity compensation plans, see “Executive Compensation—Employee Benefit Plans” under Item 11 and as incorporated by reference from our Proxy Statement on Form 14A.

Critical Accounting Policies

Oil and Gas Producing Activities

We use 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 our experience of successful drilling, terms of leases 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. Our 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, we recognize 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 resulting 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.

Our estimate of proved reserves is based on the quantities of oil and gas that engineering and geological analysis demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. Our reserve estimates and the projected cash flows are derived from these reserve estimates, in accordance with SEC guidelines by an independent engineering firm based in part on data provided by us. The accuracy of our reserve estimates depends in part on the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions, and the judgments of the individuals preparing the estimates.

Revenue Recognition

Affiliated partnerships enter into agreements with us to drill wells to completion for a fixed price. We, in turn, enter 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. We recognize revenue from the turnkey drilling agreements on a proportional performance method as services are performed. This involves management making judgments and estimates as to their various stage of completion of each well based on the review of drilling logs, status reports from engineers and historical experience in completing similar wells. When estimates of future revenues and expenses on a specific contract indicate a loss will be incurred, the total estimated loss is accrued.

Oil and gas sales result from undivided interests held by us 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 us of oil and gas produced by affiliated joint ventures and partnerships and are recognized when delivered to purchasers.

Well services revenue is recognized when services are performed.

New Accounting Pronouncement

In December 2004, the FASB issued SFAS No. 123(R), “Share−Based Payment”. This Statement revises SFAS No. 123, “Accounting for Stock−Based Compensation” and supersedes APB Opinion No. 25, “Accounting for Stock Issued to Employees.” SFAS No. 123(R) focuses primarily on the accounting for transactions in which an entity obtains employee services in share−based payment transactions. SFAS No. 123(R) requires companies to recognize in the statement of operations the cost of employee services received in exchange for awards of equity instruments based on the grant−date fair value of those awards.

SFAS 123(R) must be adopted no later than January 1, 2006 and permits public companies to adopt its requirements using one of two methods:

- A “modified prospective” method in which compensation cost is recognized beginning with the effective date based on the requirements of SFAS 123(R) for all share−based payments granted after the adoption date and based on the requirements of SFAS 123 for all awards granted to employees prior to the effective date of SFAS 123(R) that remain unvested on the adoption date.
- A “modified retrospective” method which includes the requirements of the modified prospective method described above, but also permits entities to restate either all prior periods presented or prior interim periods of the year of adoption based on the amounts previously recognized under SFAS 123 for purposes of pro forma disclosures.

The Company adopted the provisions of SFAS 123(R) on January 1, 2006 using the modified prospective method. The estimated future expense relating to unvested options at January 1, 2006, that are vesting during 2006 and 2007 totals approximately $112,000.

In May 2005, the FASB issued Statement of Financial Accounting Standards No. 154 (SFAS 154) “Accounting Changes and Error Corrections—a replacement of APB Opinion No. 20 and FASB Statement No. 3.” SFAS 154 establishes retrospective application as the required method for reporting a change in accounting principle, unless it is impracticable in which the changes should be applied to the latest practicable date presented for voluntary accounting changes and in the absence of specific guidance provided for in a new pronouncement issued by an authoritative body. SFAS 154 also requires that a correction of an error be reported as a prior period adjustment by restating prior period financial statements. SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005.

In April 2005, the FASB issued Staff Position No. FAS 19−1, “Accounting for Suspended Well Costs”. FSP FAS 19−1 amended SFAS No. 19, “Financial Accounting and Reporting by Oil and Gas Producing Companies” (“SFAS 19”), to allow continued capitalization of exploratory well costs beyond one year from the completion of drilling under circumstances where the well has found a sufficient quantity of reserves to justify its completion as a producing well and the enterprise is making sufficient progress assessing the reserves and the economic and operating viability of the project. FSP FAS 19−1 also amended SFAS 19 to require enhanced disclosures of suspended exploratory well costs in the notes to the consolidated financial statements. The Company adopted the new requirements during the fourth quarter of 2005. The adoption of FSP FAS 19−1 did not impact the Company’s consolidated financial position or results of operations.

Results of Operations

Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

Oil and gas sales. Revenue from oil and gas sales increased $7.5 million to $14.0 million during 2005, a 116% increase compared to 2004. This increase resulted from our acquisition of substantially all of the remaining working interests in the Wilmington Townlot Unit in California. Additionally, this increase reflects drilling wells for our own account. Prior to the third quarter of 2005, all wells were syndicated to our drilling programs. Net production for 2005 and 2004 was 1,959 Bcfe and 1,226 Bcfe, respectively. Additionally, the average realized price per Mcfe for 2005 and 2004 was $7.13 and $5.26, respectively.

Production & exploration. Production and exploration expense increased $3.3 million during 2005 to $7.3 million, an 85% increase compared to 2004. This increased resulted from an increase in lease operating expenses related to the Wilmington Townlot Unit in California. The Company has incurred significant start up repair and maintenance costs associated with the implementation of our drilling plan. Additionally, increases in production and exploration expense result from increases in oil and gas production.

Turnkey contract revenue and expenses. Turnkey contract revenue decreased $0.8 million during 2005 to $9.8 million, a 7% decrease compared to 2004. Additionally, turnkey contract expense decreased $1.7 million during 2005 to $11.3 million, a 13% decrease compared to 2004. The drilling activity on behalf of the drilling programs was less active during 2005 compared to 2004.

Loss from turnkey activities before allocation of depreciation and interest expense was $1.5 million for 2005 compared to a loss of $2.4 million for 2004. The loss from turnkey activities during 2005 and 2004 results from increased drilling costs.

Oil and gas sales and costs from marketing activities. Oil and gas sales from marketing activities increased $4.0 million during 2005 to $10.2 million, a 65% increase compared to 2004. Cost of oil and gas marketing activities increased $4.1 million during 2005 to $10.1 million, a 67% increase compared to 2004. These increases resulted from increases in oil and gas production from the wells in the drilling programs in which we earn a marketing fee. This production was 1.8 Bcfe and 1.4 Bcfe for 2005 and 2004, respectively. The average price per Mcfe during 2005 and 2004 was $5.60 and $4.45, respectively.

The gross profit from marketing activities for 2005 was $132 thousand compared to $143 thousand in 2004.

Well services activities. Well services revenue increased $0.5 million during 2005 to $1.6 million, a 45% increase compared to 2004. Well services expense increased $0.5 million during 2005 to $1.1 million. The increases in well services revenue and expense results from a joint venture between Anadarko Petroleum Corporation and Warren that commenced during 2005. Under this joint venture, we charge a fee for the use of our jointly owned compression facilities and sales lines.

Gross profit from well services activities was $0.4 million for 2005 and 2004.

Net gain on investments. Net gain on investments was $1.0 million for 2005. Net loss on investments was $42 thousand for 2004. Primarily, investments represent zero coupon U.S. treasury bonds. Fluctuations in net gain or loss on investments resulted from changes in long−term interest rates.

Interest and other income. Interest and other income increased $1.2 million in 2005 to $3.3 million, a 58% increase compared to 2004. This represents an increase in interest earned on idle cash balances.

Depreciation, Depletion, Amortization and Impairment. Depreciation, depletion, amortization and impairment expense decreased $0.5 million for 2005 to $3.6 million, a 12% decrease compared to last year. This decrease results from $2.3 million of impairment expense in 2004 compared to $0.2 million in 2005. The decrease was offset by an increase in depletion expense of $1.6 million resulting from an increase in oil and gas production from the Wilmington Townlot Unit in California and an increase in the cost basis of the Wilmington Townlot Unit.

General and administrative expenses. General and administrative expenses decreased $0.6 million during 2005 to $7.5 million, an 8% decrease compared to last year. This decrease results from a litigation accrual of $1.8 million recorded during the fourth quarter of 2004. The decrease was offset by an increase of $1.0 million in general and administrative expense resulting from the allocation of less general and administrative expense to turnkey activities during 2005. Additionally, the decrease was offset by an increase in the number of employees.

Interest expense. Interest expense increased $1.3 million during 2005 to $1.8 million, a 255% increase compared to last year. Interest expense increased significantly during 2005 because we are no longer capitalizing interest costs related to the Wilmington Townlot Unit in California. The Company capitalized interest totaling $1.7 million during 2005 compared to $5.9 million during 2004.

Retirement of debt. Retirement of debt expense was $1.9 million during 2005. There was no retirement of debt expense in 2004. This expense represents a premium paid on redemption of the debentures and the write off of unamortized deferred offering costs associated with the early redemption of debentures during 2005.

Income Taxes. We follow the provisions of Statements of Financial Accounting Standards No. 109, "Accounting for Income Taxes", which provides for recognition of a deferred tax liability or asset for temporary 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, unrealized gains on investments and our investment basis in oil and gas partnerships.

As of December 31, 2005, we had a net operating loss carryforward of approximately $84 million. As of December 31, 2005, we have provided a 100% valuation allowance on our net deferred tax assets. Our net operating loss carryforwards expire in 2012 and subsequent years.

Year Ended December 31, 2004 Compared to Year Ended December 31, 2003

Turnkey contract revenue and expenses. Turnkey contract revenue decreased $800,000 during 2004 to $10.5 million, a 7% decrease compared to the preceding year. Additionally. Turnkey contract expense increased $5.6 million during 2004 to $12.9 million, a 78% increase compared to 2003.

Loss from turnkey activities before depreciation and interest expense was $2.4 million for 2004. This compared to income of $4.0 million for 2003. This loss resulted from a significant increase in drilling costs, such as drilling rig rates and steel prices. In addition, income decreased during 2004 as a result of drilling Washakie wells with lower profit margins in 2004 as compared to drilling shallow re−entry wells in 2003 with higher profit margins.

Oil and gas sales and costs from marketing activities. Oil and gas sales from marketing activities increased $600,000 in 2004 to $6.2 million, a 10% increase compared to 2003. Cost of oil and gas marketing activities increased $500,000 in 2004 to $6.0 million, a 10% increase compared to 2003. Oil and gas production from the wells in the drilling programs in which we earn a marketing fee for 2004 and 2003 was 1.4 Bcfe and 1.2 Bcfe, respectively. The average price per Mcfe during 2004 and 2003 was $5.26 and $3.92, respectively.

The gross profit from marketing activities for both 2004 and 2003 was $100,000.

Well service activities. Well services revenue decreased $100,000 in 2004 to $1.1 million, an 8% decrease compared to 2003. Well services expense increased $11,000 in 2004 to $700,000.

Gross profit from well services activities was $400,000 and $500,000, respectively for 2004 and 2003. The decrease in gross profit during 2004 resulted from lower supervision and overhead activity during 2004.

Oil and gas sales. Revenue from oil and gas sales increased $700,000 in 2004 to $6.5 million, a 13% increase compared to 2003. The increase was offset by a retroactive adjustment that reduced our oil and gas sales in accordance with the reduction in our working interest percentage in the Sun Dog unit in the

Washakie Basin. In accordance with the Washakie Basin unit Operating Agreement, our working interest percentage increases or decreases as the field unit expands.

Net gain (loss) on investments. Net loss on investments was $42,000 for 2004. Net gain on investments was $22,000 during 2003. Our investments consist primarily of 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.

Interest and other income. Interest and other income increased $700,000 in 2004 to $2.1 million, a 56% increase compared to 2003. The increase results from the receipt of accounts receivables that were previously written off.

Gain on sale of assets. The $500,000 gain on the sale of assets in 2003 resulted from the sale of certain non−strategic properties in New Mexico.

Production & exploration expenses. Production and exploration expense increased $100,000 in 2004 to $3.9 million, a 3% increase compared to 2003. This increase resulted from an increase in the volume of oil and gas sales. Additionally, we incurred increased lease operating expenses related to our Washakie Basin properties. The increase was offset by a retroactive adjustment which reduced our production and exploration expense in accordance with the reduction in our working interest percentage in the Sun Dog unit in the Washakie Basin.

Depreciation, depletion, amortization and impairment. Depreciation, depletion, amortization and impairment expense increased $800,000 for 2004 to $4.0 million, a 24% increase compared to last year. This increase represents a higher cost basis in oil and gas properties in 2004 due to the recapitalization of our drilling programs, as compared to 2003, resulting in a higher depletion expense. Additionally, this increase resulted from impairment expense of $1.0 million and $300,000 in 2004 and 2003, respectively. These increases were offset by a decrease in expense resulting from the expiration of certain leases.

General and administrative expenses. General and administrative expenses increased $3.6 million in 2004 to $8.1 million, an 81% increase compared to last year. This increase resulted from recording a liability relating to the Gotham lawsuit totaling $1.8 million. See “Business—Legal Proceedings”. Additionally, this increase reflects an increase in legal fees relating to our California property. See “Business—Legal Proceedings”. Lastly, this increase reflects an increase of $1.2 million resulting from allocating of certain expenses to general and administrative expense during 2004 instead of turnkey expense. As the Company focuses on drilling more for its own account, less G&A expense will be charged to turnkey expense in the future periods.

Interest Expense. Interest expense decreased $1.0 million in 2004 to $500,000, a 68% decrease compared to last year. This decrease reflects an increase in the amount of interest capitalized on our Wyoming and California properties due to the recapitalization of our drilling programs.

Debentures

As of December 31, 2005, we had $2.6 million of convertible debentures that are convertible into our common shares. As of December 31, 2004, we had $46.5 million of debentures outstanding. On January 12, 2005 and January 13, 2005, we called the 2007 and 2017 sinking fund debentures, with outstanding balances at December 31, 2004 of $9.0 million and $5.0 million respectively. These debentures were redeemed on March 31, 2005 at a premium of 2% for the 2007 bonds and 6% for the 2017 bonds. As a result of our common stock price attaining certain levels, we were able to call the flowing debentures: on April 29, 2005, we called the 2010 sinking fund debentures with an outstanding balance of $14.4 million at December 31, 2004. These debentures were redeemed on June 30, 2005 at a premium of 10%. On September 21, 2005, we called the 2015 sinking fund debentures with an outstanding balance of $11.6 million at December 31, 2004. These debentures were redeemed on December 23, 2005 without a premium. On October 3, 2005, we called the 2009, 2010, and 2016 debentures with outstanding balances of $0.8 million, $1.7 million, and $1.3 million at December 31, 2004, respectively. These debentures were redeemed on December 27, 2005 at a premium of 10% each. The remaining $2.6 million balance of our debentures are callable from 2006 to 2022 at our option without premiums.

Further, all convertible debentures are callable by us if the average bid price of our common shares publicly traded at 133% or greater of the respective conversion price of the debentures for at least 90 consecutive trading days. In such an event, debentures not converted may be called by us upon 60 days notice at a price of 100% of par value plus accrued interest.

We have issued secured debentures. The principal of the secured debentures is secured at maturity by zero coupon U.S. treasury bonds previously deposited into an escrow account equaling the par value of the debentures maturing on or before the due date of the debentures.

The table below reflects the outstanding debentures by issue, the fair market value of the zero coupon U.S. treasury bonds held in escrow on behalf of the debentures holders and the estimated cash outlay for the payment of debenture interest for 2006. The conversion prices listed below will increase in the future.

Debentures (in thousands, except for conversion prices)	Conversion Outstanding at December 31, 2005	Fair Market Price as of December 31, 2005	Estimated Value of U.S. Treasuries	Debenture Interest for 2006
12% Secured Fund Debentures due December 31, 2020	$ 1,470	$ 25.00	$ 739	$ 177
12% Secured Fund Debentures due December 31, 2022	1,136	25.00	519	136
	$ 2,606		$ 1,258	$ 313

Preferred Stock

As of December 31, 2005, we had 652,336 shares of convertible preferred stock issued and outstanding.

During 2005, 5,838,161 shares of our convertible preferred stock converted into common shares on a 1 for 1 basis and 70,312 shares of preferred stock converted into common shares on a 1 to 0.75 basis.

Dividends and accretion on preferred shares totaled $3.8 million and $6.6 million for the years ended December 31, 2005 and 2004, respectively.

All of our outstanding preferred stock has a dividend equal to 8% per annum, payable to the extent legally available quarterly in arrears, and a liquidation preference of $12.00 per share. Any accrued but unpaid dividends shall be cumulative and paid upon liquidation, optional redemption or conditional repurchase. No dividends may be paid on the common stock as long as there are any accrued and unpaid dividends on the preferred stock.

The following describes the conversion rate applicable to the preferred shares outstanding at December 31, 2005:

- At the election of the holder of our convertible preferred stock, until June 30, 2006, each share of preferred stock is convertible into 0.75 shares of common stock, and commencing July 1, 2006 and thereafter, each share of preferred stock is convertible into 0.50 shares of common stock.

The conversion rate for our convertible preferred stock is subject to adjustment in the event of:

- the issuance of common stock as a dividend or distribution on any class of our capital stock;
- the combination, subdivision or reclassification of the common stock; or
- the distribution to all holders of common stock of evidences of indebtedness or assets, including securities issued by third parties, but excluding cash dividends or distributions paid out of surplus.

Commencing seven years after their respective date of issuance, the preferred stock may be redeemed by the holders at a redemption price equal to the liquidation value of $12.00 per share, plus accrued but unpaid dividends, if any. At December 31, 2005, there were 599,256 preferred shares outstanding that the Company may be required to redeem during the year ended December 31, 2010, and thereafter, 53,080 preferred shares outstanding that the Company may be required to be redeemed during the year ended December 31, 2011 and thereafter.

Upon receipt of a redemption election, we, at our option, shall either:

- pay the holder cash in an amount equal to $12.00 per convertible preferred share, subject to adjustment for stock splits, stock dividends or stock exchanges, plus accrued and unpaid dividends, to the extent that we have funds legally available for redemption, or
- issue to the holder shares of common stock in an amount equal to 125% of the cash redemption price and any accrued and unpaid dividends, based on the average of the closing sale prices of our common stock for the 30 trading days immediately preceding the date of the receipt of the written redemption election by the holder, as reported by the Nasdaq Stock Market, or by any exchange or electronic OTC listing service on which the shares of common stock are then traded. In the event that we elect to pay the Redemption Price in kind with our common stock, for each 2.1 million shares of preferred stock representing $25.2 million of Redemption Price value, notwithstanding the market price of our common stock, we shall not issue to the redeeming preferred stockholders less than their proportionate share of 2.1 million of our shares of common stock, nor be obligated to issue more than 3.15 million shares of our common stock in full satisfaction of the redemption, subject to adjustment for stock splits, stock dividends and stock exchanges.

If we are not listed on an exchange or our common stock has no trading volume, upon redemption the Board shall determine the fair market value of the common stock.

If the closing sale price of our publicly traded common stock as reported by the Nasdaq Stock Market, or any exchange or electronic OTC listing service on which the shares of common stock are then traded, exceeds 133% of the conversion price then in effect for the preferred stock for at least 10 trading days during any 30−day period, we, at our option, may either:

- redeem the preferred stock in whole or in part, at a redemption price of $12.00 per share plus accrued and unpaid dividends, or

- convert the preferred stock, plus any accrued and unpaid dividends, into common stock at the then applicable conversion rate, based on the average closing sale prices of our common stock for the 30 trading days immediately preceding the date fixed for redemption.

In addition, the preferred stock, plus accrued and unpaid dividends, shall be converted into common stock at the then applicable conversion rate upon the vote or written consent of the holders of 66 2/3% of the then outstanding preferred stock, voting together as a class.

Accordingly, if the holders of any of the then−remaining outstanding shares of our preferred stock request redemption commencing in 2009 and thereafter and we elect to pay the Redemption Price for the preferred stock in cash, we would need capital of $12.00 per share, plus the amount of any accrued but unpaid dividends, which funds may not be available and the payment of which could have a material adverse effect on our financial liquidity and results of operation. Alternatively, if we elect to pay the Redemption Price for the preferred stock commencing in 2009 and thereafter with shares of our common stock, such issuance could materially increase the number of our shares of common stock then outstanding and be dilutive to our earnings per share, if any.

Contractual Obligations

The contractual obligations table below assumes the maximum amount is tendered each year. The table does not give effect to the conversion of any bonds to common stock which would reduce payments due. As described in more detail in the “Debentures” section above, all debentures are secured at maturity by zero coupon U.S. treasury bonds deposited into an escrow account equaling the par value of the debentures maturing on or before the maturity of the debentures.

	Payments due by period				
Contractual Obligations As of December 31, 2005	**Total**	**Less Than 1 Year**	**1−3 Years**	**4−5 Years**	**More Than 5 Years**
Debentures	$ 2,606,000	$ 260,600	$ 445,626	$ 360,957	$ 1,538,817
Drilling Commitments	14,330,900	9,816,900	4,514,000	—	—
Leases	605,827	218,106	304,775	82,946	—
Total	$ 17,542,727	$ 10,295,606	$ 5,264,401	$ 443,903	$ 1,538,817

The contractual obligation schedule above does not reflect $2.6 million principal amount of zero coupon U.S. treasury bonds held by us in escrow to secure the repayment of the debentures upon maturity. Such U.S. treasury bonds had a fair market value of $1.3 million at December 31, 2005.

The Company has a contract with Nabors Well Services Co. (Contractor) for drilling wells in California that expires September 1, 2007. The contract provides for an operating rate of $18,500 per day. In the event of early termination, a shortfall charge of $8,000 per day is incurred for each day prior to the initial termination date, which is limited to a maximum of $1,500,000.

The Company has a contract with Caza Drilling Inc. (Contractor) for drilling wells in California that expires October 1, 2006. The contract provides for an operating rate of $11,100 per day. In the event of early termination, the company will incur a force majeure rate of $4,800 per day for each day prior to the initial termination date and actual cost incurred by the contractor, for a maximum of $1,315,200 in 2006.

Off−Balance Sheet Arrangements

Under the terms of our drilling programs formed from 1998 to 2001, investors have the right to tender their interest back to the drilling program and other program investors during the period from seven to 25 years after the date of the partnership’s formation. The tender rights were included to make such programs more attractive to potential investor partners, thereby enabling the Company to obtain more capital to drill more oil and gas wells. To the extent that an investor tenders a drilling program interest for sale and the drilling program and other investors elect not to repurchase the withdrawing partner's interest, we will be required to repurchase the interest from the investor. The price of our repurchase is fixed by the drilling program agreement to be the lower of the PV−10 value of the assets of the program and a formula based on the amount of the investor's cash investment reduced by the amount of any cash distributions received. As of December 31, 2005, based on the December 31, 2005 reserve reports of the respective drilling programs, the aggregate PV−10 value of the assets in these programs is $45.0 million. Because this PV−10 value is less than the formula price of $90.7 million at December 31, 2005, the maximum repurchase price obligation at December 31, 2005 was $45.0 million. This PV−10 value would be higher if current prices for crude oil and natural gas were to increase when we drill the remaining 3 net wells or place the remaining 54 net wells on production on behalf of these seven drilling programs. In the event of repurchase, we receive the investor's interest in the program, which includes the investor's beneficial share of the program's reserves and related future net cash flows. There are no known events that would result in termination of the material benefits of our off−balance sheet arrangements except for a decrease in oil and gas pricing that occurs after an acquisition. The only material off−balance sheet benefit of this arrangement is the acquisition of proved reserves. To the extent that we acquire interests for their PV−10 value based on this arrangement, and declining oil and natural gas prices, or other factors, render those interests less valuable, a material reduction in the benefit of this arrangement to the Company would occur.

The table below presents the projected timing of our maximum potential repurchase commitment associated with these programs as of December 31, 2005:

	Amount of repurchase commitment per period				
	Less Than 1 Year	**1−3 Years**	**4−5 Years**	**More Than 5 Years**	**Total**
			(in thousands)		
Maximum potential repurchase commitment (1)	$ 11,420	$ 32,915	—	$ 702	$ 45,037

(1) Based on the partnership reserves taken from the Williamson partnership reserve report as of December 31, 2005 and using pricing at that date. This report does not include reserves for 3 net wells that are scheduled to be drilled for these programs in 2006 or for the 54 net wells drilled and waiting to be placed on production.

Commencing January 1, 2006, we may be obligated to commence purchasing drilling program interests at their PV−10 value. As a result, the following factors may affect the liquidity and capital resources of the Company:

- An increase in the price of oil and natural gas, or an increase in the amount of proved reserves (from drilling the remaining 3 net wells that are scheduled to be drilled for these drilling programs during 2005, from the 54 net wells drilled and waiting to be placed on production, or from other factors) may increase the PV−10 value of the drilling programs and, as a result, increase the price of our repurchase. After the acquisition of any drilling program interests, oil and natural gas prices may decline, resulting in a decline in the expected future net cash flow or the fair market value of the assets acquired in the repurchase and a possible recording of impairment expense.
- If our existing capital is inadequate to fund the repurchase of drilling program interests, we may be unable to obtain financing, or obtain financing on terms acceptable to us, to purchase the drilling program interests at their PV−10 value.

Additional Repurchase Commitments

Under the terms of 13 of our drilling programs formed before 1998, the minority interest investors have the right to require us to repurchase their interests in each program for a formula price, to the extent that the drilling programs and other program investors elect not to purchase a withdrawing partner's interest. This right is effective either seven years from the date of a partnership's formation, or between the 15th and 25th anniversary of its formation. The formula price is computed as the original capital contribution of the investor reduced by the greater of cash distributions we made to the investor, or 10% for every $1.00 which the oil price at the repurchase date is below $13.00 per barrel adjusted by the CPI changes since the program's formation. If we purchase interests in drilling programs, we receive the investor's interest in the program, which includes the investor's beneficial share of the reserves and related future net cash flows. The table below presents the repurchase commitment associated with the pre−1998 drilling programs, giving no effect to any reserve value that is acquired in repurchase. This amount is collateralized by U.S Treasury Bonds with a market value of approximately $215,000.

	Amount of repurchase commitment per period				
Other Commitments As of December 31, 2005	**Less Than 1 Year**	**1−3 Years**	**4−5 Years**	**More Than 5 Years**	**Total**
			(in thousands)		
Partnership repurchase commitments:					
Pre−1998 Partnerships	—	—	$ 16	$ 359	$ 375

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 expected to continue.

Interest Rate Risk

We hold investments in U.S. treasury bonds available for sale, which represents securities held in escrow accounts on behalf of the drilling programs and purchasers of certain debentures. Additionally, we hold 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

Our financial instruments consist of cash and cash equivalents, U.S. treasury bonds, accounts receivable and payable and other long−term liabilities. The carrying amounts of cash and cash equivalents, U.S. treasury bonds, accounts receivables and accounts payable approximate fair market value due to the highly liquid nature of these short−term instruments.

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.

Item 8: Financial Statements and Supplementary Data

See Report of Registered Public Accounting Firm and Audited Financial Statements at Item 15.

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

None.

Item 9A: Controls and Procedures

Disclosure Controls and Procedures.

We maintain controls and procedures designed to ensure that information required to be disclosed in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Evaluations have been performed under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as such terms are defined in Rule 13a–15(e) and 15d–15(e) of the Exchange Act). Based upon those evaluations, management, including the Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures were adequate and effective as of December 31, 2005 to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the Exchange Act are recorded, processed, summarized and reported, within the time periods specified in the SEC’s rules and forms. Pursuant to the evaluation performed in connection with the filing of this Amendment, management has confirmed that our disclosure controls and procedures were adequate and effective as of December 31, 2005 and continue to be adequate and effective as of the date of this filing.

Our management does not expect that our disclosure controls and procedures will prevent all errors and all fraud. The design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Based on the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected. These inherent limitations include the realties that judgments in decision−making can be faulty and that breakdowns can occur because of simple errors or mistakes. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events. Therefore, a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Our disclosure controls and procedures are designed to provide such reasonable assurances of achieving our desired control objectives and the Chief Executive Officer and the Chief Financial Officer, as of December 31, 2005, have concluded that our disclosure controls and procedures are effective in achieving that level of reasonable assurance.

Management’s Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. As defined in Exchange Act Rule 13a−15(f), internal control over financial reporting is a process designed by, or under the supervision of, our Chief Executive Officer and Chief Financial Officer and effected by our Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we carried out an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2005 based on the criteria in “Internal Control—Integrated Framework” issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”). Based upon this evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2005.

Grant Thornton LLP, the independent registered public accounting firm that audited our financial statements included in this Annual Report on Form 10−K, has also audited our management’s assessment of the effectiveness of the Company’s internal control over financial reporting and the effectiveness of the Company’s internal control over financial reporting as of December 31, 2005 as stated in their report included herein.

Changes in Internal Control over Financial Reporting.

There were no changes in internal control over financial reporting that occurred during the fourth quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting

Item 9B: Other Information.

Not applicable.

PART III

Item 10: Directors and Executive Officers of the Registrant

See "Executive Officers, Board of Directors, Committees of the Board and Section 16(a) Beneficial Ownership Reporting Compliance" in the Warren Resources, Inc. Proxy Statement ("Proxy Statement"), for the Annual Meeting of Stockholders of Warren Resources, Inc. to be held on May 17, 2006 (to be filed with the SEC within 120 days after the end of the Company's fiscal year ended December 31, 2005) which is incorporated herein by reference.

The Company's Code of Business Conduct and Ethics and the Code of Ethics for the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer (Code of Ethics) can be found on the Company's internet website located at www.warrenresources.com. If the Company amends the Code of Ethics or grants a waiver, including an implicit waiver, from the Code of Ethics, the Company intends to disclose the information on its internet website. This information will remain on the website for at least 12 months.

Item 11: Executive Compensation

Information required by this item will be contained in the Proxy Statement under the caption "Executive Compensation," and is hereby incorporated by reference thereto.

Item 12: Securities Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information required by this item will be contained in the Proxy Statement under the caption "Securities Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters" and is incorporated herein by reference.

Item 13: Certain Relationships and Related Transactions

Information required by this item will be contained in the Proxy Statement under the caption "Certain Transactions," and is hereby incorporated by reference thereto.

Item 14: Principal Accountant Fees and Services

Information required by this item will be contained in the Proxy Statement under the caption "Auditors' Fees," and is hereby incorporated by reference thereto.

PART IV

Item 15: Exhibits, Financial Statement Schedules

(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(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(13)	Articles of Incorporation of Registrant filed May 20, 2004 (Maryland)
3.2(10)	Bylaws of the Registrant, dated June 2, 2004
3.3(10)	Articles Supplementary (Series A 8% Cumulative Convertible Preferred Stock ($.0001 Par Value) (Maryland)
3.4(10)	Certificate of Correction to Articles Supplementary (Series A 8% Cumulative Convertible Preferred Stock) (Maryland)
3.5(10)	Articles Supplementary (Series A Institutional 8% Cumulative Convertible Preferred Stock ($.0001 Par Value) (Maryland)
3.6 (10)	Certificate of Correction to Articles Supplementary (Series A Institutional 8% Cumulative Convertible Preferred Stock) (Maryland)
4.1(13)	Specimen Stock Certificate for Common Stock (Maryland)
4.2(8)	Form of Class A Common Stock Warrant
4.3(8)	Form of Class B Common Stock Warrant
4.4(3)	Form of Registration Rights Agreement made as of December 12, 2002, by and between Warren Resources the Investors in the Series A 8% Cumulative Convertible Preferred Stock.
4.5(6)	Form of Subscription and Registration Rights Agreement dated February 3, 2004 by and between Warren Resources, Inc. and the Accredited Investors in Warren Resources, Inc.'s private placement dated January 21, 2004
4.6(10)	Form of Subscription and Registration Rights Agreement dated July 30, 2004 by and between Warren Resources, Inc. and the Accredited Investors in Warren Resources, Inc.'s private placement dated July 9, 2004
4.7(5)	Form of Contribution Agreement by and between Warren Resources, Inc., and various Delaware limited liability companies.
10.1(1)	2000 Equity Incentive Plan for Warren E&P Subsidiary
10.2(1)	Amendment to 2000 Stock Incentive Plan for Warren E&P Subsidiary

10.3(1)	2001 Stock Incentive Plan
10.4(1)	2001 Key Employee Stock Incentive Plan
10.5(1)	Employment Agreement dated January 1, 2001, between the Registrant and Norman F. Swanton
10.6(1)	Employment Agreement dated January 1, 2001, between the Registrant and Timothy A. Larkin
10.7(9)	Amendment to Employment Agreement dated January 1, 2004, between the Registrant and Norman F. Swanton
10.8(15)	Second Amendment to Employment Agreement dated June 17, 2005, between the Registrant and Norman F. Swanton
10.9(9)	Amendment to Employment Agreement dated January 1, 2004, between the Registrant and Timothy A. Larkin
10.10(15)	Second Amendment to Employment Agreement dated June 17, 2005, between the Registrant and Timothy A. Larkin
10.11(15)	Employment Agreement dated as of July 1, 2005, between the Registrant and Lloyd Davies
10.12(15)	Employment Agreement executed on June 17, 2005, between the Registrant and David E. Fleming
10.13(10)	Employment Agreement dated January 1, 2004, between the Registrant and Ellis G. Vickers
10.14(1)	Form of Indemnification Agreement
10.15(1)	Form of Partnership Production Marketing Agreement
10.16(4)	Exchange Agreement dated as of the 11th day of December, 2002, between Anadarko E&P Company LP, and Warren Resources, Inc.
10.17(4)	Joint Exploration Agreement, dated December 13, 2002 between Warren Resources, Inc., Anadarko E&P Company LP, and Anadarko Land Corp.
10.18(4)	Form of Rocky Mountain Unit Operating Agreement Between Anadarko E&P Company, LP and Warren Resources, Inc.
10.19(11)	Purchase and Sale Agreement dated November 24, 2004 by and among Warren Resources of California, Inc., Magness Petroleum Company and Next Generation Investments, LLC.
10.20(11)	Settlement Agreement and Release dated November 24, 2004 by and among Warren Resources, Inc., Warren Resources of California, Inc., Warren E&P, Inc., Warren Development Corp. and Magness Petroleum Company.
10.21(14)	Asset Purchase Agreement dated December 9, 2005 by and among Warren Resources, Inc., Warren Resources of California, Inc., Warren E&P, Inc. and Global Oil Production, LLC and Wilmington Management, LLC
11†	Statements regarding Computation of Per Share Earnings (Included in the Financial Statement in Part 4)
14(7)	Code of Ethics for Senior Financial Officers
21.1(12)	Subsidiaries of the Registrant
23.1†	Consent of Williamson Petroleum Consultants, Inc.
23.2†	Consent of Grant Thornton LLP
31.1†	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes−Oxley Act of 2002
31.2 †	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes−Oxley Act of 2002.
32 †	Section 1350 Certification

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

(2) 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.

(3) Incorporated by reference to the Company's Current Report on Form 8−K filed on December 12, 2002.

(4) Incorporated by reference to the Company's Current Report on Form 8−K filed on December 24, 2002.

(5) Incorporated by reference to the Company's Quarterly Report on Form 10−Q for the quarter ended June 30, 2003.

(6) Incorporated by reference to the Company's Current Report on Form 8−K, Commission File No. 000−33275, filed on February 11, 2004.

(7) Incorporated by reference to the Company's Annual Report on Form 10−K for the year ended December 31, 2002, filed on March 31, 2003.

(8) Incorporated by reference to the Company's Annual Report on Form 10−K for the year ended December 31, 2003, filed on March 15, 2004.

(9) Incorporated by reference to the Company's Quarterly Report on Form 10−Q for the quarter ended March 31, 2004, filed May12, 2004.

(10) Incorporated by reference to the Company's Quarterly Report on Form 10−Q for the quarter ended June 30, 2004, filed on August 13, 2003.

(11) Incorporated by reference to the Company's Current Report on Form 8−K, Commission File No. 000−33275, filed November 30, 2004.

(12) Incorporated by reference to the Company's Registration Statement on From S−1/A, Commission File No. 333−118535, filed December 2, 2004.

(13) Incorporated by reference to the Company's Annual Report on Form 10−K for the year ended December 31, 2004, filed on March 17, 2005.

(14) Incorporated by reference to the Company's Current Report on Form 8−K, Commission File No. 000−33275, filed December 12, 2005.

(15) Incorporated by reference to the Company's Current Report on Form 8−K, Commission File No. 000−33275, filed June 17, 2005.

† Filed herewith.

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	Executive Vice President, Chief Financial Officer, and Principal Accounting Officer

Dated: March 8, 2006

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 8, 2006
/s/ Timothy A. Larkin Timothy A. Larkin	Executive Vice President, Chief Financial Officer and Principal Accounting Officer	March 8, 2006
/s/ Anthony Coelho Anthony Coelho	Director	March 8, 2006
/s/ Lloyd Davies Lloyd Davies	Director	March 8, 2006
/s/ Dominick D'Alleva Dominick D'Alleva	Director	March 8, 2006
/s/ Marshall Miller Marshall Miller	Director	March 8, 2006
/s/ Thoman Noonan Thomas Noonan	Director	March 8, 2006
/s/ Michael R. Quinlan Michael R. Quinlan	Director	March 8, 2006
/s/ Chet Borgida Chet Borgida	Director	March 8, 2006
/s/ Leonard Dececchis Leonard Dececchis	Director	March 8, 2006

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Report of Independent Registered Public Accounting Firm

Board of Directors
Warren Resources, Inc.

We have audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, appearing under item 9A, that Warren Resources, Inc. and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control − Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on criteria established in Internal Control − Integrated Framework issued by COSO. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control − Integrated Framework issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of the Company as of December 31, 2005 and 2004, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2005 and our report dated March 8, 2006 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
March 8, 2006

Report of Independent Registered Public Accounting Firm

Board of Directors
Warren Resources, Inc.

We have audited the accompanying consolidated balance sheets of Warren Resources, Inc. and Subsidiaries (the “Company”) as of December 31, 2005 and 2004, and the related consolidated statements of operations, stockholders’ equity and cash flows for each of the three years in the period ended December 31, 2005. These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Warren Resources, Inc. and Subsidiaries as of December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, 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, 2003, the Company changed its method of accounting for asset retirement obligations as required by the provisions of Statement of Financial Accounting Standards No. 143, *Asset Retirement Obligations*.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company’s internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control − Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 8, 2006 expressed an unqualified opinion on management’s assessment of the effectiveness of the Company’s internal control over financial reporting and an unqualified opinion on the effectiveness of the Company’s internal control over financial reporting.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
March 8, 2006

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

	2005	2004
ASSETS		
Current Assets		
Cash and cash equivalents	$114,632,099	$ 99,920,885
Accounts receivable—trade	3,945,862	1,481,925
Accounts receivable from affiliated partnerships	118,356	143,297
Trading securities	—	174,247
Restricted investments in U.S. Treasury bonds—available for sale, at fair value (amortized cost of $96,959 in 2005 and $5,944,587 in 2004)	125,771	6,099,968
Other current assets	2,356,583	211,509
Total current assets	121,178,671	108,031,831
Other Assets		
Oil and gas properties—at cost, based on successful efforts method of accounting, net of accumulated depreciation, depletion, amortization and impairment	185,904,194	116,595,306
Property and equipment—at cost, net	559,612	395,444
Restricted investments in U.S. Treasury bonds—available for sale, at fair value (amortized cost of $1,387,910 in 2005 and $10,778,899 in 2004)	1,821,181	12,062,085
Deferred bond offering costs, net of accumulated amortization of $253,537 in 2005 and $4,080,257 in 2004	277,700	2,360,812
Goodwill	3,430,246	3,430,246
Other assets	7,592,799	4,034,937
Total other assets	199,585,732	138,878,830
	$320,764,403	$246,910,661
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Current maturities of debentures	$ 260,600	$ 17,316,070
Current maturities of other long−term liabilities	325,994	353,516
Accounts payable and accrued expenses	25,042,379	16,153,851
Deferred income—turnkey drilling contracts with affiliated partnerships	1,765,829	11,908,389
Total current liabilities	27,394,802	45,731,826
Long−Term Liabilities		
Debentures, less current portion	2,345,400	29,160,630
Other long−term liabilities, less current portion	5,974,493	3,207,809
	8,319,893	32,368,439
Minority Interest	7,009,634	11,240,990
Commitments and Contingencies		
Stockholders' Equity		
8% convertible preferred stock—$.0001 par value; authorized, 10,000,000 shares; issued and outstanding, 652,336 shares in 2005 and 6,560,809 shares in 2004 (aggregate liquidation preference $7,828,032 in 2005 and $78,729,708 in 2004)	7,629,622	77,270,413
Common stock—$.0001 par value; authorized, 100,000,000 shares; issued, 52,738,384 shares in 2005 and 34,347,854 shares in 2004	5,274	3,435
Additional paid−in capital	353,714,161	157,847,314
Accumulated deficit	(82,861,220)	(77,689,476)
Accumulated other comprehensive income, net of applicable income taxes of $185,000 in 2005 and $576,000 in 2004	280,292	865,775
	278,768,129	158,297,461
Less common stock in Treasury—at cost; 632,250 shares in 2005 and 2004	728,055	728,055
Total Stockholders' Equity	278,040,074	157,569,406
	$320,764,403	$246,910,661

The accompanying notes are an integral part of these statements.

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

	2005	2004	2003
Revenues			
Oil and gas sales	$13,959,097	$ 6,454,334	$ 5,717,814
Turnkey contracts with affiliated partnerships	9,756,209	10,529,883	11,300,646
Oil and gas sales from marketing activities	10,210,681	6,171,338	5,620,522
Well services, 70%, 84%, and 81% with affiliated partnerships, respectively	1,554,760	1,070,004	1,167,564
Net gain (loss) on investments	960,995	(42,916)	21,761
Interest and other income	3,302,034	2,088,994	1,340,059
Gain on sale of unproved oil and gas properties	203,487	120,193	494,497
	39,947,263	26,391,830	25,662,863
Expenses			
Production and exploration	7,295,520	3,935,137	3,811,595
Turnkey contracts	11,275,348	12,932,124	7,284,653
Cost of marketed oil and gas purchased from affiliated partnerships	10,078,848	6,028,727	5,500,426
Well services	1,146,590	672,933	662,128
Depreciation, depletion, amortization and impairment	3,552,839	4,022,725	3,249,860
General and administrative	7,475,919	8,116,164	4,496,034
Interest	1,761,465	493,977	1,528,069
Retirement of debt	1,862,164	—	—
	44,448,693	36,201,787	26,532,765
Loss before provision for income taxes, minority interest and change in accounting principle	(4,501,430)	(9,809,957)	(869,902)
Deferred income tax expense (benefit)	391,000	(59,000)	129,000
Net loss before minority interest and change in accounting principle	(4,892,430)	(9,750,957)	(998,902)
Minority interest	(279,314)	(209,341)	(112,263)
Net loss before change in accounting principle	(5,171,744)	(9,960,298)	(1,111,165)
Cumulative effect of change in accounting principle	—	—	(88,218)
Net loss	(5,171,744)	(9,960,298)	(1,199,383)
Less dividends and accretion on preferred shares	3,774,395	6,590,886	4,561,543
Net loss applicable to common stockholders	$ (8,946,139)	$(16,551,184)	$(5,760,926)
Basic and diluted loss per common share	$ (0.23)	$ (0.84)	$ (0.34)
Weighted average common shares outstanding	39,177,816	19,739,048	16,827,857

The accompanying notes are an integral part of these statements.

Warren Resources, Inc. and Subsidiaries
CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY
Years ended December 31, 2005, 2004 and 2003

	Preferred stock		Common stock		Additional paid−in capital	Accumulated deficit	Accumulated other comprehensive income	Treasury stock	Total Stockholders' equity
	Shares	Amount	Shares	Amount					
Balance at January 1, 2003	1,784,197	$ 20,955,838	17,581,996	$ 1,758	$ 52,424,147	$ (66,529,795)	$ 971,508	$ (821,583)	$ 7,001,873
Retirement of common stock	—	—	(232,926)	(23)	(123,445)	—	—	93,528	(29,940)
Dividends declared on preferred stock	—	—	—	—	(4,272,297)	—	—	—	(4,272,297)
Issuance of preferred stock, net of offering costs of $2,048,730	4,723,532	55,088,940	—	—	—	—	—	—	55,088,940
Accretion of preferred stock to redemption value	—	289,246	—	—	(289,246)	—	—	—	—
Comprehensive loss									
Net loss	—	—	—	—	—	(1,199,383)	—	—	(1,199,383)
Comprehensive loss									
Net change in unrealized gain on investment securities available for sale, net of applicable income taxes	—	—	—	—	—	—	(195,149)	—	(195,149)
Total comprehensive loss									(1,394,532)
Balance at December 31, 2003	6,507,729	76,334,024	17,349,070	1,735	47,739,159	(67,729,178)	776,359	(728,055)	56,394,044
Issuance of common stock, net of offering costs of $6,805,458	—	—	16,793,980	1,679	115,802,018	—	—	—	115,803,697
Shares issued from exercise of options	—	—	186,056	19	744,205	—	—	—	744,224
Shares issued from exercise of Class A Warrants	—	—	8,482	1	84,819	—	—	—	84,820
Conversion to common stock from debentures	—	—	10,266	1	67,999	—	—	—	68,000
Dividends declared on preferred stock	—	—	—	—	(6,282,213)	—	—	—	(6,282,213)
Issuance of preferred stock, net of offering costs of $9,232	53,080	627,716	—	—	—	—	—	—	627,716
Accretion of preferred stock to redemption value	—	308,673	—	—	(308,673)	—	—	—	—
Comprehensive loss									
Net loss	—	—	—	—	—	(9,960,298)	—	—	(9,960,298)
Comprehensive loss									
Net change in unrealized gain on investment securities available for sale, net of applicable income taxes	—	—	—	—	—	—	89,416	—	89,416
Total comprehensive loss									(9,870,882)
Balance at December 31, 2004	6,560,809	77,270,413	34,347,854	3,435	157,847,314	(77,689,476)	865,775	(728,055)	157,569,406

Warren Resources, Inc. and Subsidiaries
CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY (Continued)
Years ended December 31, 2005, 2004 and 2003

	Preferred stock		Common stock		Additional paid−in	Accumulated	Accumulated other comprehensive	Treasury	Total Stockholder's
	Shares	Amount	Shares	Amount	capital	deficit	income	stock	equity
Balance at December 31, 2004	6,560,809	77,270,413	34,347,854	3,435	157,847,314	(77,689,476)	865,775	(728,055)	157,569,406
Issuance of common stock, net of offering costs of $5,362,421	—	—	7,498,021	750	100,416,701	—	—	—	100,417,451
Shares issued from exercise of options	—	—	942,985	94	4,173,350	—	—	—	4,173,444
Shares issued from exercise of warrants	—	—	214,831	22	2,265,211	—	—	—	2,265,233
Conversion to common stock from debentures	—	—	3,859,251	386	23,267,583	—	—	—	23,267,969
Conversion to common stock from preferred stock	(5,908,473)	(69,738,041)	5,890,895	589	69,737,452	—	—	—	—
Retirement of common stock	—	—	(15,453)	(2)	(219,055)	—	—	—	(219,057)
Dividends declared on preferred stock	—	—	—	—	(3,677,145)	—	—	—	(3,677,145)
Accretion of preferred stock to redemption value	—	97,250	—	—	(97,250)	—	—	—	—
Comprehensive loss									
Net loss	—	—	—	—	—	(5,171,744)	—	—	(5,171,744)
Net change in unrealized gain on investment securities available for sale, net of applicable income taxes	—	—	—	—	—	—	(585,483)	—	(585,483)
Total comprehensive loss									(5,757,227)
Balance at December 31, 2005	652,336	$ 7,629,622	52,738,384	$ 5,274	$ 353,714,161	$ (82,861,220)	$ 280,292	$ (728,055)	$ 278,040,074

The accompanying notes are an integral part of these statements.

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

	2005	2004	2003
Cash flows from operating activities:			
Net loss	$ (5,171,744)	$ (9,960,298)	$ (1,199,383)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:			
Accretion of discount on available for sale debt securities	(553,332)	(669,882)	(563,495)
Amortization and write−off of deferred bond offering costs	1,158,865	396,160	633,051
Gain on sale of U.S. Treasury bonds—available for sale	(1,117,239)	(58,693)	(132,827)
Depreciation, depletion, amortization and impairment	3,552,839	4,022,725	3,249,860
Accretion of asset retirement obligation	75,771	52,771	62,452
Cumulative effect of accounting change	—	—	88,218
Gain on sale of oil and gas properties	(203,487)	(120,193)	(494,497)
Expense on the issuance of warrants	21,705	—	—
Common stock surrendered in settlement of receivable	(219,057)	—	—
Deferred tax expense (benefit)	391,000	(59,000)	129,000
Change in assets and liabilities:			
(Increase) decrease in trading securities	174,247	26,906	(122,769)
(Increase) decrease in accounts receivable—trade	(2,403,937)	904,255	4,509,303
Decrease in accounts receivable from affiliated partnerships	24,941	245,974	531,981
(Increase) decrease in other assets	(5,702,936)	2,362,056	810,183
Increase in accounts payable and accrued expenses	9,779,832	7,122,794	3,633,658
Decrease in deferred income from affiliated partnerships	(10,142,560)	(10,529,883)	(5,223,496)
Increase (decrease) in other long−term liabilities	(13,069)	1,757,769	(633,611)
Net cash provided by (used in) operating activities	(10,348,161)	(4,506,539)	5,277,628
Cash flows from investing activities:			
Purchase, exploration and development of oil and gas properties	(71,591,433)	(27,093,223)	(12,699,505)
Purchases of property and equipment	(344,923)	(9,725)	(40,043)
Proceeds from sale of oil and gas properties, net of selling fees	372,864	120,193	494,497
Proceeds from sale of property and equipment	—	24,000	52,353
Purchases of U.S. Treasury bonds—available for sale	—	(2,367,786)	(5,692,731)
Proceeds from U.S. Treasury bonds—available for sale	16,909,189	293,858	723,442
Decrease in restricted cash	—	—	3,637,775
Net cash used in investing activities	(54,654,303)	(29,032,683)	(13,524,212)
Cash flows from financing activities:			
Payments on long−term debt	(19,816,280)	(1,620,679)	(1,911,336)
Issuance of common stock, net	101,104,552	116,632,741	—
Issuance of preferred stock, net	—	126,730	14,304,156
Dividends paid on preferred stock	(1,574,594)	(6,207,684)	(2,772,233)
Purchase of treasury stock	—	—	(29,940)
Net cash provided by financing activities	79,713,678	108,931,108	9,590,647
Net increase in cash and cash equivalents	14,711,214	75,391,886	1,344,063
Cash and cash equivalents at beginning of year	99,920,885	24,528,999	23,184,936
Cash and cash equivalents at end of year	$114,632,099	$99,920,885	$24,528,999

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

Supplemental disclosure of cash flow information:			
Cash paid for interest, net of amount capitalized	$ 1,467,949	$ 45,082	$ 895,018
Cash paid for income taxes	—	—	—
Noncash investing and financing activities:			
Conversion to common stock from convertible debt	$24,132,500	$ 68,000	$ —
Exchange of 2007 Sinking Fund Bond for preferred stock	—	—	3,858,392
Exchange of 2017 Sinking Fund Bond for preferred stock	—	—	864,160
Accrued preferred stock dividend	383,786	1,574,594	1,500,064
Preferred stock issued to minority interest	—	500,986	3,782,664
Preferred stock issued to acquire property	—	—	7,972,000
Common stock issued to pay dividends	3,293,355	—	—
During 2003, the Company acquired affiliated L.L.C. interests in exchange for 1,641,628 shares of preferred stock. In conjunction with the acquisition, assets were acquired and liabilities were assumed as follows:			
Estimated fair value of assets acquired			$28,346,462
Liabilities assumed			8,646,926
Estimated fair value of preferred stock			$19,699,536
During 2003, the Company recorded the cumulative effect of SFAS 143 for asset retirement obligations, as follows:			
Increase to oil and gas properties			$ 557,465
Increase of asset retirement obligation			645,683
Cumulative effect of accounting change			$ 88,218

The accompanying notes are an integral part of these statements.

NOTE A—ORGANIZATION AND ACCOUNTING POLICIES

Nature of Operations

Warren Resources, Inc. (the “Company” or “Warren”), was formed on June 12, 1990 under the laws of the State of New York for the purpose of acquiring and developing oil and gas properties. On September 5, 2002, the Company changed its state of incorporation to Delaware. On July 7, 2004, the Company changed its state of incorporation to Maryland. As a result, all shares of the Company’s stock were converted into shares of the Maryland Corporation. The Company’s properties are primarily located in New Mexico, North Dakota, Texas, Wyoming and California. In addition, the Company serves as the managing general partner (the “MGP”) to affiliated partnerships and joint ventures.

Principles of Consolidation

The consolidated financial statements include accounts of the Company, its wholly−owned subsidiaries, Warren Development Corp., Warren Drilling Corp., Warren Management Corp., Warren Resources of California, Inc, Warren Energy Services LLC and Warren E & P, Inc. The Company has consolidated thirteen limited liability companies formed between 1994 and 1997 in which the Company has a majority ownership interest in the standard LLC membership interest and control of the entity, thereby giving it majority control for financial reporting purposes. All significant intercompany accounts and transactions have been eliminated in consolidation.

Historically, the Company entered into joint venture agreements with limited partnerships whereby the Company assigned 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. Payout is achieved when the limited partners in a particular partnership 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 partnerships less any applicable lease operating expenses. Once payout is achieved, the Company has a total interest of 55% in the net revenue generated from all wells assigned to a particular partnership. The Company primarily incurs lease acquisition costs and completion costs, including lease and well equipment, on wells developed in these partnerships and joint ventures. The Company proportionately consolidates its share of the costs incurred on undivided working interests in the post−1998 partnerships, in which it does not have majority control.

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

NOTE A—ORGANIZATION AND ACCOUNTING POLICIES (Continued)

allowance. Other unproved properties are amortized based on the Company's experience of successful drilling, terms of leases 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 drilling 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.

Revenue Recognition

Affiliated partnerships enter into agreements with the Company 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 a proportional performance method as services are performed. When estimates of future revenues and expenses on a specific contract indicate that a loss will be incurred, the total estimated loss is accrued.

Well services revenue is recognized when services are performed.

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 that exceed federally insured limits. At December 31, 2005, the Company had approximately 68% and 18% of its cash and cash equivalents with two financial institutions. 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.

NOTE A—ORGANIZATION AND ACCOUNTING POLICIES (Continued)

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 from joint interest owners and oil and gas purchasers. Credit is extended based on evaluation of a customer’s financial condition and, generally, collateral is not required. Accounts receivable under joint operating agreements generally have a right of offset against future oil and gas revenues if a producing well is completed. 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.

Investments

The Company classifies its debt 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). Current available−for−sale securities represent the par value of zero coupon Treasury Bonds associated with our current redeemable debt. Realized gains and losses are determined on the basis of specific identification of the securities.

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. Costs associated with the issuance of preferred and common stock are reflected as a reduction of proceeds. Preferred stock is accreted to its liquidation value over seven years from the date of issuance.

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.

NOTE A—ORGANIZATION AND ACCOUNTING POLICIES (Continued)

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

The Company capitalizes interest relating to its California and Wyoming properties in accordance with Statement of Financial Accounting Standards (“SFAS”) No. 34, *Capitalization of Interest Costs*. Assets qualifying for interest capitalization represent lease costs associated with undeveloped acreage on which exploration activities are in progress. Interest capitalization commences when activities necessary to ready the asset for its intended use have been incurred and continues as long as activities necessary to get the lease ready for its intended use are in progress. If the Company suspends these activities, interest capitalization shall cease until activities are resumed. However, brief interruptions and interruptions that are externally imposed do not result in cessation.

Interest of approximately $1,700,000, $5,900,000 and $5,700,000 was capitalized during the years ended December 31, 2005, 2004 and 2003, respectively, relating to California and Wyoming properties on which exploration activities were in progress during 2005, 2004 and 2003.

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

The Company has a stock−based employee plan, which is described more fully in Note D to the consolidated 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 provisions of SFAS No. 123, *Accounting for Stock−Based Compensation*, the

NOTE A—ORGANIZATION AND ACCOUNTING POLICIES (Continued)

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

	2005	2004	2003
Net loss applicable to common stockholders			
As reported	$ (8,946,139)	$(16,551,184)	$(5,760,926)
Deduct: Stock−based employee compensation expense under SFAS 123	(2,645,396)	(963,483)	(2,147,458)
Pro forma	$(11,591,535)	$(17,514,667)	$(7,908,384)
Basic and diluted loss per common share:			
As reported	$ (0.23)	$ (0.84)	$ (0.34)
Pro forma	$ (0.30)	$ (0.89)	$ (0.47)

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 2005, 2004 and 2003, respectively: No expected dividends, weighted average volatility of 29%, 28% and 31%, risk−free interest rates of 3.69%, 3.60% and 3.25% and expected lives of 5 years for incentive options issued in 2005, 2004 and 2003, respectively. The volatility assumptions were developed using a peer group of similar energy companies and our stock price. The weighted average fair value of the options issued in 2005, 2004 and 2003 was $3.14, $2.90 and $1.57, respectively.

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 10 years. Major classes of property and equipment consisted of the following at December 31:

	2005	2004
Equipment	$ 957,913	$ 957,913
Automobiles and trucks	274,940	30,433
Furniture and fixtures	253,120	152,704
Land and buildings	99,237	99,237
Office equipment	101,371	101,371
	1,686,581	1,341,658
Less accumulated depreciation, amortization and impairment	1,126,969	946,214
	$ 559,612	$ 395,444

Earnings (Loss) Per Common Share

Basic earnings (loss) per common share is computed by dividing the net earnings (loss) applicable to common stockholders 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 and preferred stock are converted using the if−converted method. Conversion or exercise is not assumed if the results are antidilutive.

NOTE A—ORGANIZATION AND ACCOUNTING POLICIES (Continued)

Potential common shares relating to options, warrants, 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,		
	2005	2004	2003
Employee stock options	2,510,721	2,625,206	2,241,012
Convertible bonds and debentures	104,240	5,188,788	5,387,820
Preferred stock	489,252	6,560,809	6,507,729
Warrants	2,968,109	3,109,643	180,625

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 0.5 (Note D).

At December 31, 2005, the Convertible Bonds may be converted until maturity at 100% of principal amount into common stock of the Company at prices ranging from approximately $25.00 to $50.00 (Note C).

Goodwill

The Company applies SFAS 142, *Goodwill and Other Intangible Assets*, which addresses financial accounting and reporting for acquired goodwill and other intangible assets and requires that goodwill and intangibles with indefinite lives no longer be amortized, but instead be periodically reviewed for impairment. There were no indicators that would indicate that the carrying amount of goodwill was impaired during the periods presented.

Asset Retirement Obligations

In June 2001, the Financial Accounting Standard Board issued SFAS No. 143, *“Accounting for Asset Retirement Obligations”* which 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. The Company adopted SFAS No. 143 on January 1, 2003 and recorded a net asset of $557,000, a related liability of $645,000 (using a 10% discount rate) and a cumulative effect of change in accounting principle on prior years of $88,000. The Company’s accretion expense is recorded as interest expense. The Company has treasury bills held in escrow with a fair market value of $2,796,000 that are legally restricted for potential plugging and abandonment liability in the Wilmington field which are recorded in non current assets in the Balance Sheet.

NOTE A—ORGANIZATION AND ACCOUNTING POLICIES (Continued)

The following illustrates the activity incurred in the asset retirement obligation, which is recorded in other long−term liabilities, at December 31:

	December 31,	
	2005	2004
Balance at beginning of year	$ 883,832	$896,448
Liabilities incurred in current year	2,910,472	7,904
Liabilities settled in current year	(168,999)	(73,291)
Accretion expense	75,771	52,771
Carrying amount	$3,701,076	$883,832

Recent Accounting Pronouncements

In December 2004, the FASB issued SFAS No. 123(R), “Share−Based Payment.” This Statement revises SFAS No. 123, “Accounting for Stock−Based Compensation” and supersedes APB Opinion No. 25, “Accounting for Stock Issued to Employees.” SFAS No. 123(R) focuses primarily on the accounting for transactions in which an entity obtains employee services in share−based payment transactions. SFAS No. 123(R) requires companies to recognize in the statement of operations the cost of employee services received in exchange for awards of equity instruments based on the grant−date fair value of those awards.

SFAS 123(R) must be adopted no later than January 1, 2006 and permits public companies to adopt its requirements using one of two methods:

- A “modified prospective” method in which compensation cost is recognized beginning with the effective date based on the requirements of SFAS 123(R) for all share−based payments granted after the adoption date and based on the requirements of SFAS 123 for all awards granted to employees prior to the effective date of SFAS 123(R) that remain unvested on the adoption date.
- A “modified retrospective” method which includes the requirements of the modified prospective method described above, but also permits entities to restate either all prior periods presented or prior interim periods of the year of adoption based on the amounts previously recognized under SFAS 123 for purposes of pro forma disclosures.

The Company adopted the provisions of SFAS 123(R) on January 1, 2006 using the modified prospective method. The estimated future expense relating to unvested options at January 1, 2006, that are vesting during 2006 and 2007 totals approximately $112,000.

In May 2005, the FASB issued Statement of Financial Accounting Standards No. 154 (SFAS 154) “Accounting Changes and Error Corrections—a replacement of APB Opinion No. 20 and FASB Statement No. 3.” SFAS 154 establishes retrospective application as the required method for reporting a change in accounting principle, unless it is impracticable in which the changes should be applied to the latest practicable date presented for voluntary accounting changes and in the absence of specific guidance provided for in a new pronouncement issued by an authoritative body. SFAS 154 also requires that a correction of an error be reported as a prior period adjustment by restating prior period financial statements. SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005.

NOTE A—ORGANIZATION AND ACCOUNTING POLICIES (Continued)

In April 2005, the FASB issued Staff Position No. FAS 19−1, “Accounting for Suspended Well Costs.” FSP FAS 19−1 amended SFAS No. 19, “Financial Accounting and Reporting by Oil and Gas Producing Companies” (“SFAS 19”), to allow continued capitalization of exploratory well costs beyond one year from the completion of drilling under circumstances where the well has found a sufficient quantity of reserves to justify its completion as a producing well and the enterprise is making sufficient progress assessing the reserves and the economic and operating viability of the project. FSP FAS 19−1 also amended SFAS 19 to require enhanced disclosures of suspended exploratory well costs in the notes to the consolidated financial statements. The Company adopted the new requirements during the fourth quarter of 2005. The adoption of FSP FAS 19−1 did not impact the Company’s consolidated financial position or results of operations.

NOTE B—INVESTMENTS

The amortized cost, unrealized gains and estimated fair values of the Company’s available−for−sale securities held are summarized as follows:

	December 31, 2005	December 31, 2004
U.S. Treasury Bonds, stripped of interest, maturing 2007 through 2023, aggregate par value of $4,070,000 and $26,048,000, respectively		
Amortized cost	$1,484,869	$16,723,486
Gross unrealized gains	462,083	1,438,567
Estimated fair value	$1,946,952	$18,162,053

During 2005, 2004 and 2003, the Company recognized approximately $156,000, $106,000 and $(87,000), respectively, of unrealized gains (losses) on its trading securities and $1,117,000, $63,000 and $109,000, respectively, of realized gains from its investments in trading and available−for−sale securities.

The realized gains for each year results 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 and debentures (Notes C & F). At December 31, 2004, the Company’s gross unrealized losses were immaterial and were netted against gross unrealized gains for the year.

The amortized cost and estimated fair values of available−for−sale securities, by contractual maturity at December 31, 2005 are shown below.

	Amortized cost	Estimated fair value
Due within one year	$ —	$ —
Due after one year through five years	11,856	13,056
Due after five years through ten years	4,347	5,151
Due after ten years	1,468,666	1,928,745
Total	$1,484,869	$1,946,952

NOTE C—LONG−TERM LIABILITIES

Debentures consist of the following at December 31:

	2005	2004
Sinking Fund Debentures and Secured Convertible Bonds retired in 2005 (1)	$ —	$43,855,700
Secured Convertible Bonds, due December 31, 2020, bearing interest at 12%, due in monthly payments. As of December 31, 2005 and 2004, principal collateralized by $1,470,000 and $1,485,000, respectively, principal amount of zero coupon U.S. Treasury Bonds due November 15, 2020. (2)	1,470,000	1,485,000
Secured Convertible Bonds, due December 31, 2022, bearing interest at 12%, due in monthly payments. As of December 31, 2005 and 2004, principal collateralized by $1,136,000 and $1,136,000 respectively, principal amount of zero coupon U.S. Treasury Bonds due November 15, 2022. (2)	1,136,000	1,136,000
	2,606,000	46,476,700
Less current maturities	260,600	17,316,070
Long−term portion	$2,345,400	$29,160,630

(1) Throughout 2005, the Company called for full redemption certain sinking fund debentures and secured convertible debentures under the terms of the original debenture agreements. As required under certain agreements, debentures were called at premiums ranging from 2% to 6%, which resulted in an expense of approximately $482,000. Of the remaining debentures called, the bond holders were given the option to either convert their bonds into shares of the Company's common stock at their conversion rate (ranging from $5 to $9 per share) or accept cash redemption. Accordingly, the Company paid approximately $5,800,000 in cash resulting in a premium of approximately $436,500 and issued 3,859,251 shares of common stock for conversion of the debentures. As a result of these redemptions, the Company wrote off approximately $930,000 of deferred offering costs and allocated approximately $901,000 of deferred offering costs to additional paid−in capital for bond conversions. Additionally these redemptions resulted in a release of restricted U.S. Treasury Bonds to the Company, having a fair market value of approximately $16,376,000.

(2) Debentures can be called at par if the Company's stock trades at or above 133% of the conversion price for a period of ninety consecutive trading days.

The Convertible Bonds 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 range from approximately $25.00 to $50.00. Conversion of the bonds would increase the number of shares outstanding at December 31 as follows:

NOTE C—LONG−TERM LIABILITIES (Continued)

2005	Maturity date	Outstanding principal amount	Per share conversion price	Common shares if converted
Secured Convertible 12% Bond	December 31, 2020	$1,470,000	$ 25.00	58,800
Secured Convertible 12% Bond	December 31, 2022	1,136,000	25.00	45,440
		$2,606,000		104,240

Due to the retirement of debt in 2005 the Company no longer has annual sinking fund requirements to purchase zero coupon U.S. Treasury Bonds as collateral for its outstanding debentures. Each year, holders of the Secured Convertible Bonds may tender to the Company up to 10% of the aggregate amount outstanding. As of December 31, 2005, the estimated principal that can be tendered by the Secured holders is as follows:

Fiscal year ending December 31	
2006	$ 260,600
2007	234,540
2008	211,086
2009	189,977
2010	170,980
Thereafter	1,538,817
	$2,606,000

Other long−term liabilities consist of the following at December 31:

	2005	2004
Other miscellaneous long−term liabilities, consisting of debt collateralized by treasury stock, asset retirement obligations (Note A) and litigation provision (Note F)	$6,300,487	$3,561,325
Less current maturities	325,994	353,516
Long−term portion	$5,974,493	$3,207,809

During 2002, the Company entered into an agreement to purchase 702,500 shares of common stock from a shareholder through the issuance of a noninterest−bearing note. The company discounted the non−interest bearing note at 10% and the outstanding balance at December 31, 2005 and 2004 was approximately $776,000 and $854,000, respectively, net of discount of approximately $290,000 and $372,000, which is included in other long−term liabilities. The note requires monthly payments of $13,333 until August 2012 and is collateralized by the treasury stock. In the event of default as defined by the agreement, the only remedy by the note−holder will be the issuance of the common stock.

NOTE D—STOCKHOLDERS' EQUITY

On December 27, 2005, the Company sold 6,900,000 shares of common stock to the public in a secondary offering at a price of $14.50 per share which included the underwriter's over−allotment option. After deducting the underwriters' commission and offering expenses, the Company received total net proceeds of approximately $94,700,000.

During 2005, the Company called for full redemption the following convertible debentures: 2009 Secured Debentures; 2010 Secured Bonds; 2010 Sinking Fund Debentures; 2015 Sinking Fund Debentures and 2016 Secured Convertible Debentures. Debenture holders were give the option to redeem for cash or receive common stock of the Company. Accordingly, the Company issued 3,859,251 shares of its common stock to certain debenture holders.

During 2005, the Company issued 323,847 shares of common stock in lieu of the second and third quarter Preferred Stock dividend payment.

On December 16, 2004, the Company sold 9,500,000 shares of common stock in an initial public offering for aggregate gross proceeds of $71,250,000. After deducting the underwriters' commission and offering expenses, the Company received net proceeds of approximately $65,263,000. On December 22, 2004, the underwriters exercised their over−allotment option for an additional 1,425,000 shares of the Company's common stock for additional gross proceeds of $10,687,500 and net proceeds of approximately $9,939,000, after deducting the underwriters' commission and offering expenses.

During 2004, the Company raised $19,950,000 through the private placement of 2,850,000 shares of common stock and issued 1,425,000 warrants to five institutional investors. The Company also sold 25,000 shares of its common stock for $175,000 and issued 12,500 warrants to a single investor. Additionally in November 2004, the Company completed an equity transaction that raised gross proceeds of $21,000,000, net proceeds after commission was $20,492,000, through the private placement of 3,000,000 shares of common stock and issued 1,500,000 warrants to purchase shares of common stock. The warrants consist of Class A and Class B warrants, which expire in five years and have an exercise price of $10 and $12.50, respectively.

During 2005 and 2004, the Company issued 942,985 and 186,056 shares of common stock to individuals who exercised options at exercise prices of $4 to $10.00 per share. Also during 2005 and 2004, the Company issued 214,831 and 8,482 shares of common stock to investors who exercised Class A warrants at $10 per share and Class B warrants at $12.50 per share.

During 2004, the Company issued 8,600 shares of common stock to certain 2010 Sinking Fund Debenture holders, convertible at $5 per share and 1,666 shares of common stock to 2017 Sinking Fund Debenture holders, convertible at $15 per share.

During 2004 and 2003, the Company issued 11,331 and 1,320,164 shares, respectively, of redeemable convertible preferred stock through a private placement with accredited investors at a price of $12 per share for gross proceeds of $135,972 and $15,841,968, respectively. Also, during 2004 and 2003, the Company issued 41,749 and 3,005,186 shares, respectively, of preferred stock to its affiliated limited partnerships under a partnership recapitalization offering at a price of $12 per share based on third−party sales to accredited investors. The Company also exchanged 393,522 shares of preferred stock for debentures in 2003. The preferred stock has an 8% cumulative dividend, payable quarterly. Preferred

NOTE D—STOCKHOLDERS' EQUITY (Continued)

dividends of approximately $384,000 and $1,600,000 were accrued at December 31, 2005 and 2004, respectively. The holders of the preferred stock are not entitled 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. Preferred stock outstanding 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	
Prior to June 30, 2005	1 to 1
July 1, 2005 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. The Company is accreting the carrying value of its preferred stock to its redemption price using the effective interest method with accretion recorded to additional paid in capital. The accretion of preferred stock results in a reduction of earnings per share applicable to common stockholders.

During 2005, the Company issued 5,838,161 shares of common stock to preferred stock investors who exchanged on a 1 to 1 basis and 52,734 shares of common stock to preferred stock investors who exchanged on a 1 to 0.75 basis. At December 31, 2005, there were 599,256 preferred shares outstanding that the Company may be required to redeem at the aggregate Redemption Price of $7,191,072 during the year ended December 31, 2010, and 53,080 preferred shares outstanding that the Company may be required to redeem at the aggregate Redemption Price of $636,960 during the year ended December 31, 2011 and thereafter. As noted above, the Company could, at its option, settle the redemption requests in shares of common stock.

During 2005, the Board of Directors approved and the Company issued 768,500 stock options to officers and employees of the Company exercisable at prices ranging from $9.05 to $14.05 per share. The options are exercisable at a price not less than the fair market value of the stock at the date of grant and have an exercisable period of five years.

As a result of job performance, during 2005 the Compensation Committee elected to accelerate the vesting of certain unvested stock options previously awarded to employees, officers and directors of the Company under various stock option plans were accelerated. As a result of this action, options to purchase approximately 1.0 million shares of our common stock that would otherwise have vested over the next two years became fully vested.

During 2004, the Board of Directors approved and the Company issued 630,250 stock options to officers and employees of the Company exercisable at $7 per share. The options are exercisable at a price not less than the fair market value of the stock at the date of grant, have an exercisable period of five years

NOTE D—STOCKHOLDERS' EQUITY (Continued)

and generally are fully vested at the date of grant. During 2004, 60,000 stock options were forfeited as a result of employee terminations.

A summary of the status of the Company's options issued to employees as of December 31, 2005, 2004 and 2003 and changes during the years ended on those dates is presented below:

	Incentive options	Weighted Average Exercise Price
Options outstanding—December 31, 2002	1,574,459	$5.29
Issued	1,374,553	$ 4.05
Exercised	—	
Expired	—	
Forfeited	(648,000)	$ 4.00
Options outstanding—December 31, 2003	2,301,012	$ 5.10
Issued	630,250	$ 7.00
Exercised	(186,056)	$ 4.00
Expired	—	
Forfeited	(60,000)	$ 4.00
Options outstanding—December 31, 2004	2,685,206	$ 5.66
Issued	768,500	$ 9.38
Exercised	(942,985)	$ 4.40
Expired	—	
Forfeited	—	$ 0.00
Options outstanding—December 31, 2005	2,510,721	$ 7.23

As of December 31, 2004 and 2003, options exercisable were 2,273,331 and 2,185,762, respectively.

The following table summarizes information about the Company's stock options outstanding at December 31, 2005:

Exercise Price	Options Outstanding at Year End	Weighted Average Remaining Life (In Years)	Options Exercisable at Year End
$4.00	766,772	2.40	766,772
$7.00	632,500	3.27	632,500
$9.05	697,500	4.11	697,500
$10.00	363,949	0.97	363,949
$11.00	10,000	4.72	10,000
$14.85	40,000	4.87	20,000
Total	**2,510,721**	**2.94**	**2,490,721**

NOTE D—STOCKHOLDERS' EQUITY (Continued)

	Warrants	Weighted Average Exercise Price
Warrants outstanding—December 31, 2002	—	$ 0.00
Issued	180,625	$ 10.00
Exercised	—	
Expired	—	
Forfeited	—	
Warrants outstanding—December 31, 2003	180,625	$ 10.00
Issued	2,937,500	$ 11.25
Exercised	(8,482)	$ 10.00
Expired	—	
Forfeited	—	
Warrants outstanding—December 31, 2004	3,109,643	$ 11.18
Issued	73,297	$ 9.45
Exercised	(214,831)	$ 10.79
Expired	—	
Forfeited	—	$ 0.00
Warrants outstanding—December 31, 2005	2,968,109	$ 11.17

NOTE E—INCOME TAXES

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

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

	2005	2004	2003
Income taxes at federal statutory rate (34%)	$(1,530,486)	$(3,335,385)	$(295,767)
Change in valuation allowance	2,649,040	4,375,484	364,836
Nondeductible expenses	49,682	45,064	46,517
State income taxes at statutory rate	(270,086)	(588,597)	(52,194)
Adjustment of estimated income tax provision of prior year	(390,594)	(482,418)	65,608
Other	(116,556)	(73,148)	—
	$ 391,000	$ (59,000)	$ 129,000

NOTE E—INCOME TAXES (Continued)

Deferred tax assets and liabilities are as follows as of December 31:

	2005	2004
Deferred tax assets relating to:		
Net operating loss carryforward	$33,741,548	$30,617,015
Other	314,400	314,400
	34,055,948	30,931,415
Less valuation allowance	31,345,047	28,696,007
Total deferred tax assets	2,710,901	2,235,408
Deferred tax liabilities relating to:		
Oil and gas properties and tangible equipment	2,304,939	1,374,536
Net unrealized gain on investments	405,962	860,872
Total deferred tax liabilities	2,710,901	2,235,408
Net deferred tax asset	$ —	$ —

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. Management believes it is more likely than not that the net deferred tax asset will not be realized by future operating results. The valuation allowance increased $2,649,040, $4,375,484 and $364,836 for the years ended December 31, 2005, 2004 and 2003, respectively.

At December 31, 2005, the Company had net operating loss carryforwards for federal income tax purposes of approximately $84,354,000, which begin to expire in 2012.

NOTE F—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. At December 31, 2005, the maximum termination compensation for all executives is $2,269,000

The Company has a contract with Nabors Well Services Co. for drilling wells in California that expires September 1, 2007. The contract provides for an operating rate of $18,500 per day. In the event of early termination, a shortfall charge of $8,000 per day is incurred for each day prior to the initial termination date, which is limited to a maximum of $1,500,000.

The Company has a contract with Caza Drilling Inc. for drilling wells in California that expires October 1, 2006. The contract provides for an operating rate of $11,100 per day. In the event of early

NOTE F—COMMITMENTS AND CONTINGENCIES (Continued)

termination, the Company will incur a force majeure rate of $4,800 per day for each day prior to the initial termination date and actual cost incurred by the contractor, for a maximum of $1,315,200 in 2006.

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 that may be incurred by such partnerships. The partnerships have no liabilities except accounts payable to the Company for lease operating and administrative expenses.

The Company has a transportation contract with Williston Basin Interstate ("WBI") through October 8, 2006 related to its LX Bar lease. 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 $0.30 per Mcf. During 2005, 2004 and 2003, the Company paid transportation fees of approximately $271,000, $185,000 and $169,000, respectively. The maximum deficiency charge through the period of contract expiration is approximately $504,000.

Repurchase Agreements

Under certain repurchase agreements, the investor partners in certain affiliated drilling programs have a right to have their interests repurchased by the Company. 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. As a result of previous recapitalizations, any payment made under this guarantee would be treated as a reduction to minority interest as shown on the Company's balance sheet. At December 31, 2005, the maximum cash outlay relating to these repurchase obligations is approximately $375,000. This amount is collateralized by U.S Treasury Bonds with a market value of approximately $215,000.

For certain other repurchase agreements relating to partnerships formed from 1998 to 2001, to the extent that the drilling programs and other program investors elect not to purchase a withdrawing partner's interest, investor partners have a right to have their interests repurchased by the Company at a formula price. This right is effective seven to 25 years from the date of the original partnership investment. In determining the amount of the repurchase obligation, the obligation is computed based on the lesser of a formula purchase price or the estimated cash flows discounted at 10% ("PV−10") from proved developed and undeveloped reserves of each partnership. At December 31, 2005, the aggregate formula purchase price with respect to these partnerships was approximately $90,707,000. However, this amount is limited to approximately $45,037,000 based on the aggregate PV−10 of the assets in these partnerships. This limitation may increase when the Company drills the remaining 3 net wells or places the remaining 54 net wells on production on behalf of these seven drilling programs and will fluctuate due to the variables in determining discounted cash flows, such as price changes and reserve revisions. In the event of repurchase, the Company receives the investor's interest in the program and the investor's pro rata share of the programs reserves and related future cash flows.

NOTE F—COMMITMENTS AND CONTINGENCIES (Continued)

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 when due at maturity. At December 31, 2005 and 2004, the face amounts of U.S. Treasury Bonds securing the Company's obligation under the Trust Indenture Agreements were $2,606,000 and $23,614,000, respectively, and the market values of these U.S. Treasury Bonds were approximately $1,257,715 and $17,048,360, respectively (see Note C).

Leases

The Company leases corporate office space in New York City, which expires in March 2008. The Company's oil and gas administrative office in Casper, Wyoming occupies 3,750 square feet under a lease currently being negotiated. In June 2005, the Company entered into an office lease in Roswell, New Mexico, which expires in May 2007. In March 2005, the Company entered into an office lease in Long Beach, California which expires in June 2010.

Future minimum annual rental payments, which are subject to escalation and include utility charges as of December 31, 2005, are as follows:

Year ending December 31	
2006	$218,106
2007	212,909
2008	91,866
2009	55,150
2010	27,796
	$605,827

Rent expense under these leases was approximately $304,000, $252,000 and $268,000 for the years ended December 31, 2005, 2004 and 2003, respectively.

Litigation

In 1998, the Company and its subsidiary, Warren E&P, Inc., were 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. 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 and other underwriters. The insurers paid approximately $1.8 million under the insurance policy and Gotham has sought a refund of approximately $1.8 million, is 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 in favor of Warren E&P on essentially all claims except its bad faith claims against Gotham, and Gotham's claims were rejected. Final judgment was rendered by the District Court on May 14, 2001 in Warren E&P's favor for the remaining policy proceeds,

NOTE F—COMMITMENTS AND CONTINGENCIES (Continued)

interest and attorneys' fees. Gotham appealed the final judgment to the San Antonio Court of Appeals, seeking a refund of approximately $1.5 million. On July 23, 2003, the San Antonio Court of Appeals reversed, in Gotham's favor, the trial court's earlier summary judgment for Warren E&P and remanded the case to the trial court for further proceedings consistent with the San Antonio Court of Appeals' decision. A hearing was held on December 17, 2004 to consider the parties' motions to determine both the amount of actual loss incurred by Gotham, the amount of judgment liability to be paid by Warren and Warren E&P and Warren's other claims against Gotham that were pending but unheard by the District Court as a result of the District Court's granting a summary judgment in Warren E&P's favor in May 2001. On January 4, 2005, the Company received an order of the trial court that Warren and Warren E&P were obligated to repay Gotham $1.8 million, along with attorneys' fees and statutory interest estimated at $966,000. At December 31, 2004, Warren recorded a provision for $1,800,000 relating to this judgement. On April 11, 2005, Warren filed to appeal the order of the trial court to the Texas Court of Appeals. In connection with the appeal, on April 14, 2005 Warren posted a supersedeas bond with the Court of Appeals in the amount of $2.9 million to cover the trial court judgment plus potential legal fees, court costs and statutory interest for the next two years. The supersedeas bond was secured by a collateral pledge of U.S. Treasury securities owned by Warren in the amount of $2.9 million, which is booked in Other Assets on the Balance Sheet. All briefings before the Court of Appeals have been completed and oral arguments were made on February 1, 2006. The Company is awaiting the decision of the Court of Appeals. Although management and counsel believe that the Company has meritorious grounds for the appeal, if the appeal is unsuccessful, the Company will pay the restitution to Gotham as ordered by the trail court.

The Company is a party to various other 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 G—EMPLOYEE BENEFIT PLANS

The Company has a retirement plan covering substantially all qualified corporate employees under section 401(k) of the Internal Revenue Code. The Company contributed for each participant a required matching contribution equal to 50% of the participant's contribution to a maximum of 6% of each employee's annual compensation. The Company's contributions vest over five years at 20% per year. The Company may also make discretionary contributions. The Company's expenses under the plan were approximately $85,000, $64,000 and $66,000 for the years ended December 31, 2005, 2004 and 2003, respectively.

NOTE H—RELATED PARTY TRANSACTIONS

Joint Venture Agreements

Warren E&P, Inc. is party to separate joint venture agreements with the affiliated partnerships. The agreements form a joint venture between Warren E&P and each partnership for the purpose of participating in the drilling and re−completion of oil and gas wells. Under the terms of the agreements, property acquisition and capital equipment costs are borne by Warren E&P. Generally, intangible drilling and development costs are borne by the partnerships.

NOTE H—RELATED PARTY TRANSACTIONS (Continued)

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 partners have received distributions equal to the partner's investment, Warren E&P 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 Warren E&P (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 recompletion 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 an unrelated entity 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 February 2, 2005, Warren closed the acquisition of all rights, titles and interests in the Wilmington Oil Field in Los Angeles County from Magness, for a price of approximately $14,800,000 in cash. The acquisition is effective as of January 1, 2005. Additionally, effective February 1, 2005, Warren's wholly owned operating subsidiary, Warren E&P, Inc., was elected operator of the Wilmington Unit.

NOTE I—FAIR VALUE OF FINANCIAL INSTRUMENTS

The following methods and assumptions were used to estimate the fair value of each class of financial instruments and do 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 and Available−For−Sale Securities. The fair values are based upon quoted market prices for those or similar investments.

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.

NOTE I—FAIR VALUE OF FINANCIAL INSTRUMENTS (Continued)

Other Long−Term Liabilities. The carrying amount approximates fair value due the current rates offered to the Company for long−term liabilities of the same remaining maturities.

	2005		2004	
	Fair value	Carrying amount	Fair value	Carrying amount
Financial assets				
Cash and cash equivalents	$114,632,099	$114,632,099	$99,920,885	$99,920,885
U.S. Treasury bonds and other investments—trading securities	—	—	174,247	174,247
U.S. Treasury bonds—available−for−sale	1,946,952	1,946,952	18,162,053	18,162,053
Financial liabilities				
Fixed rate debentures	$ 3,114,363	$ 2,606,000	$49,460,549	$46,476,700
Other long−term liabilities	4,477,332	4,477,332	1,738,168	1,738,168

NOTE J—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:

	2005	2004	2003
Property acquisition—unproved	$ 2,509,272	$ 3,046,654	$ 9,967,002
Property acquisition—proved	41,347,474	4,495,283	28,389,424
Exploration costs	9,927,037	902,564	525,098
Development costs	17,807,650	18,648,722	10,425,296
	$71,591,433	$27,093,223	$49,306,820

Effective January 1, 2005, we acquired all of the right, title and interest in the Wilmington Townlot Unit for $14.8 million (Note H). Additionally on December 9, 2005, we acquired all of the right, title and interest in the North Wilmington Unit for $23 million and Warren E&P was elected the new operator of the property.

Asset retirement costs of approximately $2,800,000, $8,000 and $307,000 are included in proved property acquisition costs for 2005, 2004 and 2003.

During the years ended December 31, 2005, 2004 and 2003, exploration costs of approximately $176,000, $143,000 and $92,000, respectively, were expensed.

NOTE J—OIL AND GAS INFORMATION (Continued)

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

	2005	2004
Unproved oil and gas properties	$ 60,254,586	$ 71,029,835
Proved oil and gas properties	192,034,405	108,618,748
	252,288,991	179,648,583
Less accumulated depreciation, depletion amortization and impairment	66,384,797	63,053,277
	$185,904,194	$116,595,306

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

	2005	2004	2003
Revenues	$13,959,097	$ 6,454,334	$ 5,717,814
Production costs	(7,119,363)	(3,792,002)	(3,719,780)
Exploration costs	(176,157)	(143,135)	(91,815)
Accretion of asset retirement obligation	(75,771)	(52,711)	(62,452)
Depreciation, depletion, amortization and impairment	(3,085,534)	(3,840,781)	(3,102,354)
Gain (Loss) from oil and gas producing activities	$ 3,502,272	$(1,374,295)	$(1,258,587)

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.

Depreciation, depletion, amortization and impairment expense was $3,085,534, $3,840,781 and $3,102,354 or $1.58, $3.13 and $2.37 per equivalent Mcf of production for the years ended December 31, 2005, 2004 and 2003, respectively. These amounts include impairment expenses, primarily for unproved properties of $208,407, $2,279,828 and $1,899,705 for the years ended December 31, 2005, 2004 and 2003, respectively.

The following table sets forth the Company's capitalized exploratory well activity during each of the years ended December 31:

	2005	2004	2003
Beginning capitalized exploratory well costs	$9,159,398	$5,158,942	$2,489,991
Additions to exploratory well costs pending the determination of proved reserves	2,002,718	4,000,456	2,668,951
Reclassifications due to determination of proved reserves	(3,559,158)	—	—
Exploratory well costs charged to expense	—	—	—
Ending capitalized exploratory well costs	$7,602,958	$9,159,398	$5,158,942

NOTE J—OIL AND GAS INFORMATION (Continued)

The following table provides an aging as of December 31, 2005, 2004 and 2003 of capitalized exploratory well costs based on the date the drilling was completed and the number of wells for which exploratory well costs have been capitalized for a period greater than one year since the date the drilling was completed:

	2005	2004	2003
Capitalized exploratory well costs that have been capitalized for a period of one year or less	$1,590,686	$6,983,859	$3,857,546
Capitalized exploratory well costs that have been capitalized for a period of more than one year	6,012,272	2,175,539	1,301,396
Ending capitalized exploratory well costs	$7,602,958	$9,159,398	$5,158,942
Number of wells with exploratory well costs that have been capitalized for a period greater than one year	42	16	13

The above exploratory well costs relate to coalbed methane wells that are drilled in out Atlantic Rim and Pacific Rim acreage.

Atlantic Rim—The Company is currently waiting on the approval of an Environmental Impact Statement covering the Atlantic Rim. Once completed, the Company can proceed with drilling additional wells adjacent to the exploratory wells and install the necessary infrastructure, including the building of a pipeline to these exploratory wells in order to bring these wells on production. The Company has already proven reserves on three pilots in the Atlantic Rim and believes that coal seam is continuous throughout the acreage.

Pacific Rim—Currently, these wells are in the dewatering phase. Due to the lack of existing commercial production in the surrounding area the Company has decided to obtain additional test results and monitor performance of these wells before booking any applicable reserves. The Company has already obtained proven reserves in one pilot in the Pacific Rim. The majority of drilling in this project took place in 2004 and 2005.

NOTE K—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

NOTE K—OIL AND GAS RESERVE DATA (UNAUDITED) (Continued)

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 Williamson Petroleum Consultants, Inc., our independent petroleum engineers, in accordance with SFAS No. 69 *Disclosures about Oil and Gas Producing Activities*.

Summary of Changes in Proved Reserves

	Year ended December 31,					
	2005		2004		2003	
	Mbbls	Mmcf	Mbbls	Mmcf	Mbbls	Mmcf
Proved reserves						
Beginning of year	14,177	18,542	15,124	15,448	12,324	8,502
Purchase of reserves in place	19,783	—	—	—	2,688	4,218
Discoveries and extensions	13,888	8,355	39	3,632	—	6,291
Revisions of previous estimates	2,715	(1,470)	(918)	279	199	(2,778)
Production	(148)	(1,074)	(68)	(817)	(87)	(785)
End of year	50,415(1)	24,353(1)	14,177(2)	18,542(2)	15,124(3)	15,448(3)
Proved developed reserves						
Beginning of year	395	8,496	476	7,006	404	4,544
End of year	2,939	10,829	395	8,496	476	7,006

(1) Included in 2005 reserves, 922 Mbbls and 136 Mmcf is attributable to consolidated subsidiaries in which there is an average 9% minority interest.

(2) Included in 2004 reserves, 2,142 Mbbls and 357 Mmcf is attributable to consolidated subsidiaries in which there is an average 23% minority interest.

(3) Included in 2003 reserves, 2,469 Mbbls and 1,028 Mmcf is attributable to consolidated subsidiaries in which there is an average 25% minority interest

NOTE K—OIL AND GAS RESERVE DATA (UNAUDITED) (Continued)

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

	December 31,		
	2005	2004	2003
	(Amounts in thousands)		
Future cash inflows	$2,714,566	$631,190	$499,693
Future production costs and taxes	(749,922)	(106,363)	(69,180)
Future development costs	(262,305)	(59,541)	(60,272)
Future income tax expenses	(470,106)	(110,161)	(87,042)
Net future cash flows	1,232,233	355,125	283,199
Discounted at 10% for estimated timing of cash flows	(769,453)	(162,480)	(137,073)
Standardized measure of discounted future net cash flows	$ 462,780(1)	$192,645(2)	$146,126(3)

(1) Included in 2005 reserves, $9,673 is attributable to consolidated subsidiaries in which there is an average 9% minority interest.

(2) Included in 2004 reserves, $26,054 is attributable to consolidated subsidiaries in which there is an average 23% minority interest.

(3) Included in 2003 reserves, $23,017 is attributable to consolidated subsidiaries in which there is an average 25% minority interest.

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

	Year ended December 31,		
	2005	2004	2003
	(Amounts in thousands)		
Sales, net of production costs and taxes	$ (6,664)	$ (2,519)	$ (1,934)
Discoveries and extensions	167,293	5,967	9,339
Purchases of reserves in place	236,700	—	30,875
Changes in prices and production costs	38,354	55,595	7,624
Revisions of quantity estimates	31,591	(14,249)	(2,882)
Net changes in development costs	(120,535)	(34)	(13,341)
Interest factor—accretion of discount	24,229	18,299	11,396
Net change in income taxes	(125,491)	(12,788)	5,677
Changes in production rates (timing) and other	24,658	(3,752)	27,954
Net increase	270,135	46,519	74,708
Balance at beginning of year	192,645	146,126	71,418
Balance at end of year	$462,780	$192,645	$146,126

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, 2005, 2004 and 2003 were $49.05, $37.59 and $28.45 per Bbl and

NOTE K—OIL AND GAS RESERVE DATA (UNAUDITED) (Continued)

$9.92, $5.30 and $4.50 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, 2006, 2007 and 2008 are $73,138,898, $113,024,164 and $76,142,320, 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 L—QUARTERLY INFORMATION (UNAUDITED)

Summarized quarterly financial data for the years ended December 31, 2005 and 2004 are as follows:

	2005				
	Quarter				
	First	Second	Third	Fourth	Year
Revenues	$8,116,798	$7,965,710	$10,017,730	$13,847,025	$39,947,263
Gross profit	2,318,993	652,843	1,275,865	1,616,740	5,684,441
Net loss applicable to common stockholders	(3,368,538)	(2,984,684)	(1,502,562)	(1,090,355)	(8,946,139)
Loss per share					
Basic and diluted	$ (0.10)	$ (0.08)	$ (0.04)	$ (0.02)	$ (0.23)

	2004				
	Quarter				
	First	Second	Third	Fourth	Year
Revenues	4,332,302	6,030,246	8,137,770	7,891,512	26,391,830
Gross profit	(142,365)	1,005,638	(195,276)	(11,359)	656,638
Net loss applicable to common stockholders	(2,704,791)	(2,903,711)	(3,523,688)	(7,418,994)	(16,551,184)
Loss per share					
Basic and diluted	$ (0.15)	$ (0.15)	$ (0.18)	$ (0.33)	$ (0.84)

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.

NOTE L—QUARTERLY INFORMATION (UNAUDITED) (Continued)

During the fourth quarter of 2004, the Company had the following significant adjustments:

- Recorded a contingent liability for $1,800,000 relating to the Gotham litigation (see Note F).
- Recognized impairment on oil and gas properties of approximately $1,000,000, as a result of the expiration of certain unproved Washakie leases and net capitalized costs exceeding the expected future net cash flow based on engineering estimates on certain properties (see Note K).

The effect of these adjustments were to increase the net loss by approximately $2,800,000 or $(.12) and $(.14) per basic and diluted share for the quarter and year ended December 31, 2004, respectively.

NOTE M − 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:

	2005	2004	2003
Revenues from external customers			
Turnkey contracts	$ 9,756,209	$10,529,883	$11,300,646
Oil and gas marketing	10,210,681	6,171,338	5,620,522
Oil and gas operations	14,162,584	6,574,527	6,212,311
Well services	1,554,760	1,070,004	1,167,564
Other	4,263,029	2,046,078	1,361,820
Total	$39,947,263	$26,391,830	$25,662,863
Interest and other income			
Turnkey contracts	$ —	$ 258	$ 4,246
Oil and gas marketing	—	—	—
Oil and gas operations	1,612	1,996	6,586
Well services	—	—	—
Other	3,300,422	2,086,740	1,329,227
Intersegment elimination	—	—	—
Total	$ 3,302,034	$ 2,088,994	$ 1,340,059
Consolidated revenues			
Total segment revenue	$35,684,234	$24,345,752	$24,301,043
Other	4,263,029	2,046,078	1,361,820
Intersegment elimination	—	—	—
Total	$39,947,263	$26,391,830	$25,662,863
Interest expense			
Turnkey contracts	$ 2,206	$ 735	$ 9,200
Oil and gas marketing	—	—	—
Oil and gas operations	75,771	52,771	62,452
Well services	—	—	—
Other	1,683,488	440,471	1,456,417
Elimination of intersegment	—	—	—
Total	$ 1,761,465	$ 493,977	$ 1,528,069

Depreciation, depletion, amortization and impairment			
Turnkey contracts	$ 103,216	$ 103,216	$ 102,534
Oil and gas marketing	—	—	—
Oil and gas operations	3,372,084	3,840,781	3,102,354
Well services	—	—	—
Other	77,539	78,728	44,972
Total	$ 3,552,839	$ 4,022,725	$ 3,249,860
Operating income (loss)			
Turnkey contracts	$ (1,624,561)	$ (2,505,934)	$ 3,908,505
Oil and gas marketing	131,833	142,611	120,096
Oil and gas operations	3,420,821	(1,252,166)	(757,504)
Well services	408,170	397,071	505,436
Other	(6,837,693)	(6,591,539)	(4,646,435)
Total	$ (4,501,430)	$ (9,809,957)	$ (869,902)
Assets			
Turnkey contracts	$ 2,455,065	$ 13,022,081	$ 23,625,826
Oil and gas marketing	192,642	192,642	192,642
Oil and gas operations	218,458,420	121,069,107	106,113,628
Well services	—	—	—
Other	99,658,276	112,626,831	21,121,567
Total	$320,764,403	$246,910,661	$151,053,663
Capital expenditures			
Turnkey contracts	$ —	$ —	$ —
Oil and gas marketing	—	—	—
Oil and gas operations	71,936,356	27,102,948	12,735,327
Well services	—	—	—
Other	—	—	4,221
Total	$ 71,936,356	$ 27,102,948	$ 12,739,548

INDEX TO EXHIBITS

Exhibit No.	Description
2.1(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(13)	Articles of Incorporation of Registrant filed May 20, 2004 (Maryland)
3.2(10)	Bylaws of the Registrant, dated June 2, 2004
3.3(10)	Articles Supplementary (Series A 8% Cumulative Convertible Preferred Stock ($.0001 Par Value) (Maryland)
3.4(10)	Certificate of Correction to Articles Supplementary (Series A 8% Cumulative Convertible Preferred Stock) (Maryland)
3.5(10)	Articles Supplementary (Series A Institutional 8% Cumulative Convertible Preferred Stock ($.0001 Par Value) (Maryland)
3.6 (10)	Certificate of Correction to Articles Supplementary (Series A Institutional 8% Cumulative Convertible Preferred Stock) (Maryland)
4.1(13)	Specimen Stock Certificate for Common Stock (Maryland)
4.2(8)	Form of Class A Common Stock Warrant
4.3(8)	Form of Class B Common Stock Warrant
4.4(3)	Form of Registration Rights Agreement made as of December 12, 2002, by and between Warren Resources the Investors in the Series A 8% Cumulative Convertible Preferred Stock.
4.5(6)	Form of Subscription and Registration Rights Agreement dated February 3, 2004 by and between Warren Resources, Inc. and the Accredited Investors in Warren Resources, Inc.'s private placement dated January 21, 2004
4.6(10)	Form of Subscription and Registration Rights Agreement dated July 30, 2004 by and between Warren Resources, Inc. and the Accredited Investors in Warren Resources, Inc.'s private placement dated July 9, 2004
4.7(5)	Form of Contribution Agreement by and between Warren Resources, Inc., and various Delaware limited liability companies.
10.1(1)	2000 Equity Incentive Plan for Warren E&P Subsidiary
10.2(1)	Amendment to 2000 Stock Incentive Plan for Warren E&P Subsidiary
10.3(1)	2001 Stock Incentive Plan
10.4(1)	2001 Key Employee Stock Incentive Plan
10.5(1)	Employment Agreement dated January 1, 2001, between the Registrant and Norman F. Swanton
10.6(1)	Employment Agreement dated January 1, 2001, between the Registrant and Timothy A. Larkin
10.7(9)	Amendment to Employment Agreement dated January 1, 2004, between the Registrant and Norman F. Swanton
10.8(15)	Second Amendment to Employment Agreement dated June 17, 2005, between the Registrant and Norman F. Swanton
10.9(9)	Amendment to Employment Agreement dated January 1, 2004, between the Registrant and Timothy A. Larkin
10.10(15)	Second Amendment to Employment Agreement dated June 17, 2005, between the Registrant and Timothy A. Larkin
10.11(15)	Employment Agreement dated as of July 1, 2005, between the Registrant and Lloyd Davies
10.12(15)	Employment Agreement executed on June 17, 2005, between the Registrant and David E. Fleming
10.13(10)	Employment Agreement dated January 1, 2004, between the Registrant and Ellis G. Vickers

10.14(1)	Form of Indemnification Agreement
10.15(1)	Form of Partnership Production Marketing Agreement
10.16(4)	Exchange Agreement dated as of the 11th day of December, 2002, between Anadarko E&P Company LP, and Warren Resources, Inc.
10.17(4)	Joint Exploration Agreement, dated December 13, 2002 between Warren Resources, Inc., Anadarko E&P Company LP, and Anadarko Land Corp.
10.18(4)	Form of Rocky Mountain Unit Operating Agreement Between Anadarko E&P Company, LP and Warren Resources, Inc.
10.19(11)	Purchase and Sale Agreement dated November 24, 2004 by and among Warren Resources of California, Inc., Magness Petroleum Company and Next Generation Investments, LLC.
10.20(11)	Settlement Agreement and Release dated November 24, 2004 by and among Warren Resources, Inc., Warren Resources of California, Inc., Warren E&P, Inc., Warren Development Corp. and Magness Petroleum Company.
10.21(14)	Asset Purchase Agreement dated December 9, 2005 by and among Warren Resources, Inc., Warren Resources of California, Inc., Warren E&P, Inc. and Global Oil Production, LLC and Wilmington Management, LLC
11†	Statements regarding Computation of Per Share Earnings (Included in the Financial Statement in Part 4)
14(7)	Code of Ethics for Senior Financial Officers
21.1(12)	Subsidiaries of the Registrant
23.1†	Consent of Williamson Petroleum Consultants, Inc.
23.2†	Consent of Grant Thornton LLP
31.1†	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes−Oxley Act of 2002
31.2†	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes−Oxley Act of 2002.
32†	Section 1350 Certification

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

(2) 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.

(3) Incorporated by reference to the Company's Current Report on Form 8−K filed on December 12, 2002.

(4) Incorporated by reference to the Company's Current Report on Form 8−K filed on December 24, 2002.

(5) Incorporated by reference to the Company's Quarterly Report on Form 10−Q for the quarter ended June 30, 2003.

(6) Incorporated by reference to the Company's Current Report on Form 8−K, Commission File No. 000−33275, filed on February 11, 2004.

(7) Incorporated by reference to the Company's Annual Report on Form 10−K for the year ended December 31, 2002, filed on March 31, 2003.

(8) Incorporated by reference to the Company's Annual Report on Form 10−K for the year ended December 31, 2003, filed on March 15, 2004.

(9) Incorporated by reference to the Company's Quarterly Report on Form 10−Q for the quarter ended March 31, 2004, filed May12, 2004.

(10) Incorporated by reference to the Company’s Quarterly Report on Form 10−Q for the quarter ended June 30, 2004, filed on August 13, 2003.

(11) Incorporated by reference to the Company’s Current Report on Form 8−K, Commission File No. 000−33275, filed November 30, 2004.

(12) Incorporated by reference to the Company’s Registration Statement on From S−1/A, Commission File No. 333−118535, filed December 2, 2004.

(13) Incorporated by reference to the Company’s Annual Report on Form 10−K for the year ended December 31, 2004, filed on March 17, 2005.

(14) Incorporated by reference to the Company’s Current Report on Form 8−K, Commission File No. 000−33275, filed December 12, 2005.

(15) Incorporated by reference to the Company’s Current Report on Form 8−K, Commission File No. 000−33275, filed June 17, 2005.

† Filed herewith.

Exhibit 23.1

CONSENT OF WILLIAMSON PETROLEUM CONSULTANTS, INC.

As independent oil & gas consultants, Williamson Petroleum Consultants, Inc. hereby consents to the use of the name Williamson Petroleum Consultants, Inc. and references to Williamson Petroleum Consultants, Inc. and to the inclusion of and references to our report, or information contained therein, entitled “Evaluation of Oil and Gas Reserves to the Combined Interests of Warren Resources, Inc. including 1) the Direct Interests in Certain Properties, 2) the Interests as the General Partner in Certain Partnerships, and 3) the Total Controlled Interests in 13 LLC’s Effective December 31, 2005 for Disclosure to the Securities and Exchange Commission Williamson Project 5.9094,” prepared for Warren Resources, Inc., in the annual report on Form 10−K of Warren Resources, Inc. for the filing dated on or about March 8, 2006.

/s/ WILLIAMSON PETROLEUM
CONSULTANTS, INC.
WILLIAMSON PETROLEUM CONSULTANTS,
INC.

Midland, Texas
March 8, 2006

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated March 8, 2006, accompanying the consolidated financial statements and management's assessment of the effectiveness of internal control over financial reporting included in the Annual Report of Warren Resources, Inc. and Subsidiaries on Form 10−K for the year ended December 31, 2005. We hereby consent to the incorporation by reference of said reports in the Registration Statements of Warren Resources, Inc. on Form S−3 (File No. 333−130109, effective December 2, 2005) and on Form S−8 (File No. 333−125277, effective May 26, 2005).

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
March 8, 2006

Exhibit 31.1

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES−OXLEY ACT OF 2002

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 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 report;

3. Based on my knowledge, the financial statements, and other financial information included in this 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 report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a−15(e) and 15d−15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a−15(f) and 15d−15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, 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 report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 8, 2006

/s/ Norman F. Swanton
Norman F. Swanton,
Chairman and Chief Executive Officer

Exhibit 31.2

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES−OXLEY ACT OF 2002

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 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 report;

3. Based on my knowledge, the financial statements, and other financial information included in this 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 report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a−15(e) and 15d−15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a−15(f) and 15d−15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, 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 report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 8, 2006

/s/ Timothy A. Larkin
Timothy A. Larkin,
Executive Vice President and Chief Financial Officer

Exhibit 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES−OXLEY ACT OF 2002

In connection with the Annual Report of Warren Resources, Inc. (the “Company”) on Form 10−K for the year ending December 31, 2005 as filed with the Securities and Exchange Commission on the date hereof (the “report”), we, Norman F. Swanton and Timothy A. Larkin, Chairman and Chief Executive Officer and Executive Vice President and Chief Financial Officer, respectively, of the registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes−Oxley Act of 2002, that to our knowledge:

(1) The report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the report fairly presents, in all material respects, the financial condition and results of operations of the registrant.

March 8, 2006
/s/ Norman F. Swanton
Norman F. Swanton
Chairman and Chief Executive Officer
/s/ Timothy A. Larkin
Timothy A. Larkin
Executive Vice President and Chief Financial Officer