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

Form 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Fiscal Year ended December 31, 2006

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to .

Commission File Number: 0-29370

Ultra Petroleum Corp.
(Exact Name of Registrant as Specified in Its Charter)

Yukon Territory, Canada	**N/A**
(Jurisdiction of Incorporation or Organization)	*(I.R.S. Employer Identification No.)*

363 North Sam Houston Parkway East, Suite 1200
Houston, Texas 77060
(Address of Principal Executive Offices) (Zip Code)

281-876-0120
(Registrant's Telephone Number, Including Area Code)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Shares, without par value	American Stock Exchange

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

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 requirement for the past 90 days. YES ☑ NO ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (Section 229.405 of this chapter) 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. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange 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 voting and non-voting common equity held by non-affiliates of the registrant was approximately $9,137,410,226 as of June 30, 2006 (based on the last reported sales price of $59.27 of such stock on the American Stock Exchange on such date).

As of February 15, 2007, there were 151,920,986 common shares of the registrant outstanding.

Documents incorporated by reference: The definitive Proxy Statement for the 2007 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2006, is incorporated by reference in Part III of this Form 10-K.

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Certain Definitions

Terms used to describe quantities of oil and natural gas and marketing

- *Bbl* — One stock tank barrel, or 42 U.S. gallons liquid volume, of crude oil or other liquid hydrocarbons.
- *Bcf* — One billion cubic feet of natural gas.
- *Bcfe* — One billion cubic feet of natural gas equivalent.
- *BOE* — One barrel of oil equivalent, converting natural gas to oil at the ratio of 6 Mcf of natural gas to 1 Bbl of oil.
- *BTU* — British Thermal Unit.
- *CFD* — Caofaedian — the Chinese designation for the area in Bohai Bay area in the vicinity of the 04/36 and 05/36 Blocks, offshore China.
- *Condensate* — An oil-like liquid produced in association with natural gas production that condenses from natural gas as it is produced and delivered into a separator or similar equipment and collected in tanks at each well prior to the delivery of such natural gas to the natural gas gathering pipeline system.
- *ICP* — Indonesian Crude Price.
- *MBbl* — One thousand barrels.
- *Mcf* — One thousand cubic feet of natural gas.
- *Mcfe* — One thousand cubic feet of natural gas equivalent, converting oil or condensate to natural gas at the ratio of 1 Bbl of oil or condensate to 6 Mcf of natural gas.
- *MMBbl* — One million barrels of oil or other liquid hydrocarbons.
- MMcf — One million cubic feet of natural gas.
- *MBOE* — One thousand BOE.
- *MMBOE* — One million BOE.
- *MMBTU* — One million British Thermal Units.

Terms used to describe the Company's interests in wells and acreage

- *Gross oil and natural gas wells or acres* — The Company's gross wells or gross acres represent the total number of wells or acres in which the Company owns a working interest.
- *Net oil and natural gas wells or acres* — Determined by multiplying "gross" oil and natural gas wells or acres by the working interest that the Company owns in such wells or acres represented by the underlying properties.
- *Prospect* — A location where hydrocarbons such as oil and gas are believed to be present in quantities which are economically feasible to produce.

Terms used to assign a present value to the Company's reserves

- *Standardized measure of discounted future net cash flows, after income taxes* — The present value, discounted at 10%, of the pre-tax future net cash flows attributable to estimated net proved reserves. The Company calculates this amount by assuming that it will sell the oil and natural gas production attributable to the proved reserves estimated in its independent engineer's reserve report for the oil and natural gas spot prices on the last day of the year, adjusted for quality and transportation. The Company also assumes that the cost to produce the reserves will remain constant at the costs prevailing on the date of the report. The assumed costs are subtracted from the assumed revenues resulting in a stream of future net cash flows. Estimated future income taxes, using rates in effect on the date of the report, are deducted from the net cash flow stream. The after-tax cash flows are discounted at 10% to result in the standardized measure of the Company's proved reserves.

- *Standardized measure of discounted future net cash flows before income taxes* — The discounted present value of proved reserves is identical to the standardized measure described above, except that estimated future income taxes are not deducted in calculating future net cash flows. The Company discloses the discounted present value without deducting estimated income taxes to provide what it believes is a better basis for comparison of its reserves to the producers who may have different income tax rates.

Terms used to classify the Company's reserve quantities

The Securities and Exchange Commission ("SEC") definition of proved oil and natural gas reserves, per Regulation S-X, is as follows:

Proved oil and natural gas reserves. Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made as defined in Rule 4-10(a)(2). Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

(a) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (1) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (2) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(b) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(c) Estimates of proved reserves do not include the following: (1) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves"; (2) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (3) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (4) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved developed reserves — Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods as defined in Rule 4-10(a)(3).

Proved undeveloped reserves — 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 as defined in Rule 4-10(a)(4).

Terms used to describe the legal ownership of the Company's oil and natural gas properties

- *Working interest* — A real property interest entitling the owner to receive a specified percentage of the proceeds of the sale of oil and natural gas production or a percentage of the production, but requiring the owner of the working interest to bear the cost to explore for, develop and produce such oil and natural gas. A working interest owner who owns a portion of the working interest may participate either as operator or by voting his percentage interest to approve or disapprove the appointment of an operator and drilling and other major activities in connection with the development and operation of a property.
- *Production sharing contract* — A commercial contract between the investor and the owner, which allows the investor to undertake large scale, long-term investments. The purpose of the production sharing contract

is to define the terms and conditions for the exploration and development of resources by replacing existing tax and license regimes with a contract based arrangement that exists for the life of the project.

Terms used to describe seismic operations

- *Seismic data* — Oil and natural gas companies use seismic data as their principal source of information to locate oil and natural gas deposits, both to aid in exploration for new deposits and to manage or enhance production from known reservoirs. To gather seismic data, an energy source is used to send sound waves into the subsurface strata. These waves are reflected back to the surface by underground formations, where they are detected by geophones which digitize and record the reflected waves. Computers are then used to process the raw data to develop an image of underground formations.
- *2-D seismic data* — 2-D seismic survey data has been the standard acquisition technique used to image geologic formations over a broad area. 2-D seismic data is collected by a single line of energy sources which reflect seismic waves to a single line of geophones. When processed, 2-D seismic data produces an image of a single vertical plane of sub-surface data.
- *3-D seismic data* — 3-D seismic data is collected using a grid of energy sources, which are generally spread over several miles. A 3-D survey produces a three dimensional image of the subsurface geology by collecting seismic data along parallel lines and creating a cube of information that can be divided into various planes, thus improving visualization. Consequently, 3-D seismic data is generally considered a more reliable indicator of potential oil and natural gas reservoirs in the area evaluated.

PART I

Item 1. ***Business.***

Ultra Petroleum Corp. ("Ultra" or the "Company") is an independent oil and gas company engaged in the development, production, operation, exploration and acquisition of oil and natural gas properties. The Company was originally incorporated on November 14, 1979, under the laws of the Province of British Columbia, Canada. Ultra remains a Canadian company, but since March 2000, has operated under the laws of The Yukon Territory, Canada pursuant to Section 190 of the *Business Corporations Act* (Yukon Territory). The Company's operations are primarily in the Green River Basin of southwest Wyoming and Bohai Bay, offshore China. The Company continually evaluates other opportunities for the acquisition, exploration and development of oil and natural gas properties.

Ultra's current domestic operations are focused on developing and expanding a tight gas sand project located in the Green River Basin in southwest Wyoming. As of December 31, 2006, Ultra owns interests in approximately 147,917 gross (79,566 net) acres in Wyoming covering approximately 230 square miles. The Company owns working interests in approximately 464 gross producing wells in this area and is operator of 50% of the 464 gross wells. In 2006, domestic production was approximately 89.5% of the Company's total oil and natural gas production on an Mcfe basis and 99.0% of the Company's estimated net proved reserves were domestic on an Mcfe basis. In 2006, domestic capital expenditures comprised approximately 95.5% of the Company's total capital expenditures.

Following the acquisition of Pendaries Petroleum Ltd. ("Pendaries") on January 16, 2001, the Company became active in oil and natural gas exploration and development covering the 04/36 Block and the 05/36 Block (jointly the "Blocks") in Bohai Bay, China. The Company owns interests in approximately 687,300 gross (130,290 net) acres in the Blocks. The exploration phase on the 04/36 Block has been extended to September 2007 and the 05/36 Block exploration phase has been extended to February 2008. After the extension was granted on the 05/36 Block, one of the parties to the contract elected not to participate in the extension and the Company chose to acquire the available exploration interest. In 2006, the Company spent approximately 4.5% of its total 2006 capital budget on developing these China fields, as well as on engineering work focused on development of additional fields and continuing exploration. A wholly-owned subsidiary of Anadarko Petroleum Corporation, Kerr-McGee China Petroleum Ltd., is the operator of the Blocks. Through its Production Sharing Contracts ("PSC"), the Company owns an interest in 79 gross (6.89 net) producing wells on the Blocks. When Ultra acquired Pendaries, there were three oil discoveries on the Blocks. Since then, six new discoveries have been made with seven of these fields now developed and on production. In addition, one discovery is being prepared for development and another discovery is still under appraisal.

The Company also owns interests in 233,011 gross (124,591 net) acres in Pennsylvania. The Company drilled 1 gross (1.0 net) test well on this acreage in 2005. During 2006, this well was brought on production and the Company commenced drilling operations on 2 gross (1.125 net) additional exploratory wells in the area. At year end 2006, one well remained drilling while the second well was suspended. Ultra continually evaluates this area to determine plans for future activity in the area.

The Company's annual report on Form 10-K, quarterly reports on Form 10-Q, and current reports on Form 8-K, as well as any amendments to such reports and all other filings pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available free of charge to the public on the Company's website at www.ultrapetroleum.com. To access the Company's SEC filings, select "Financials" under the Investor Relations tab on the Company's website. You may also request a copy of these filings at no cost by making written or telephone requests for copies to Ultra Petroleum Corp., Manager, Investor Relations, 363 N. Sam Houston Pkwy. E., Suite 1200, Houston, TX 77060, (281) 876-0120.

Any materials that the Company has filed with the SEC may be read and/or copied at the SEC's Public Reference Room at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an internet site that contains reports, proxy and information statements, and other information regarding us. The SEC's website address is www.sec.gov.

Business Strategy

Green River Basin, Wyoming

In 2007, the Company plans to continue its ongoing program to identify, develop and explore the acreage position now held in the tight gas sand trend in the Green River Basin. The Company expects that the majority of the wells drilled during 2007 will target the sands of the upper Cretaceous Lance Pool in the Pinedale and Jonah fields. The Lance Pool, as administered by the Wyoming Oil and Gas Conservation Commission ("WOGCC"), includes sands of both the Lance (found at subsurface depths of approximately 8,000 to 12,000 feet) and Mesaverde (found at subsurface depths of approximately 12,000 to 14,000 feet) in the Pinedale and Jonah fields area of Sublette County, Wyoming. The Company plans to drill delineation, step-out and exploration wells on its Green River Basin acreage positions in an ongoing attempt to further define and expand the current known producing limits of these two field areas. Work is continuing in an effort to assess the need for further increased density drilling to more efficiently recover the vast resources present in the area. Currently, the Pinedale field is approved by the WOGCC for a mix of well densities ranging from 1 well per 40-acre government quarter (40-acre equivalent) section down to 16 wells per government quarter section (10-acre equivalent). In the Jonah field, the current spacing is 8 wells per 80-acre drilling and spacing unit (10-acre spacing) with several pilots testing spacing at 16 wells per 80-acre drilling and spacing unit (5-acre spacing). In addition to the ongoing efforts in the Lance Pool section, the Company is drilling a deep test to further evaluate the potential for production from the Rock Springs, Blair and Hilliard Formations which underlie much of the Company's acreage position in the Pinedale field. All of the Company's drilling activity is conducted utilizing its extensive integrated geological and geophysical data set. This data set is being utilized to map the potentially productive intervals, to identify areas for future extension of the Lance fairway and to identify deeper objectives which may warrant drilling.

Bohai Bay, China

In 2007, the Company plans to continue producing oil at the CFD 11-1, 11-2, 11-3, 11-5, and the unitized 11-6, 12-1 and 12-1S fields and to begin development planning for the CFD 2-1 discovery. The Company also plans to drill an additional exploration well during 2007. The Company has nine discovered oil fields in the Bohai Blocks with seven fields on production, one field being readied for development and one remaining in the appraisal stage.

Pennsylvania

The Company is currently drilling a second test well in the Marshlands prospect area and during 2007 plans to drill at least one more test of the Silurian Tuscarora formation. Ultra plans to continue to evaluate its acreage holding in the area, acquire additional acreage, seismic and geologic data in the area as needed, and develop an overall strategy to assess the potential of the area and bring that potential to production in a timely and cost effective manner. The initial discovery well continues to produce above expectations and the Company continues to monitor its production to gather additional information to guide future decisions on development. During 2006, the Company also participated in 1 gross (.125 net) exploratory well drilled by others to evaluate a portion of the acreage position. Drilling operations on this well are suspended and the wellbore is being evaluated.

Marketing and Pricing

Ultra derives its revenues principally from the sale of its natural gas and associated condensate production from wells operated by the Company and others in the Green River Basin in southwest Wyoming. To a lesser extent, the Company derives revenues from the sale of its share of oil production from its producing fields in the Bohai Bay area, offshore China. The Company also derives a small portion of its revenues from the sale of natural gas in Pennsylvania. The Company's revenues are determined, to a large degree, by prevailing natural gas prices for production situated in the Rocky Mountain Region of the United States, specifically, southwest Wyoming, and to a lesser extent by prevailing prices for crude oil produced in the Bohai Bay region of China and natural gas in Pennsylvania. Energy commodity prices in general, and the Company's regional prices in particular, have been highly volatile in the past, and such high levels of volatility are expected to continue in the future. The Company cannot predict or control the market prices for the sale of its natural gas, condensate, or oil production.

The Company, from time to time, in the regular course of its business, has hedged a portion of its natural gas production primarily through the use of fixed price, forward sales of physical gas, or through the limited use of financial swaps with creditworthy financial counterparties. The Company may elect to hedge additional portions of its forecast natural gas production in the future, in much the same manner as it has done previously. The Company has not, to date, hedged any of its Chinese oil production; although, it may do so in the future. For a more detailed description of the Company's hedging activities, see Item 7A. Quantitative and Qualitative Disclosures About Market Risk. The Company's hedging policy limits the amounts of resources hedged to not more than 50% of its forecast production without Board approval. As a result of its hedging activities, the Company may realize prices that are less than the spot prices that it would have received otherwise.

Natural Gas Marketing

Ultra currently sells all of its natural gas production to a diverse group of third-party, non-affiliated entities in a portfolio of transactions of various durations (daily, monthly and longer term). The Company's customers are predominately located in the western United States — primarily California and the Pacific Northwest, as well as the Front Range area of Colorado and in Utah. The sale of the Company's natural gas is "as produced". As such, the Company does not maintain any significant inventories or imbalances of natural gas. The Company maintains credit policies intended to mitigate the risk of uncollectible accounts receivable. The Company does not have any outstanding, uncollectible accounts for its natural gas sales.

During 2006, the Company re-negotiated gathering and processing agreements with one of its midstream service providers that gathers, compresses and processes natural gas owned or controlled by the Company from its producing wells in the Pinedale Anticline field in southwest Wyoming. Under these agreements, the midstream service provider will expand its facility capacities in southwest Wyoming to accommodate growing volumes from wells in which the Company owns an interest. These agreements or amendments, whichever is applicable to the area, contain multi-year commitments for midstream services. The Company lowered some of the gathering and processing fees for such midstream services, in exchange for committing to these longer term arrangements. As a result of such negotiations (in both 2005 and 2006), two new, large cryogenic gas processing plants are currently being constructed in southwest Wyoming, and are projected to be completed during 2007. The new facilities will add incremental cryogenic processing capacity of approximately 1.1 Bcf per day to the southwest Wyoming area. The Company has contractually secured capacity at both of these facilities for the processing of its natural gas. Ultra believes that the capacity of the midstream infrastructure related to the Company's production will continue to be adequate to allow it to sell essentially all of its available production.

During 2006, the Company realized natural gas prices that were lower than those seen in the previous year in the southwest Wyoming region. The market price for natural gas in the Rockies generally, and in southwest Wyoming specifically, is influenced by a number of regional and national factors; all of which are unpredictable and beyond the Company's ability to control or to predict. These factors include, among others, weather, natural gas supplies, natural gas demand, and pipeline export capacity. A warmer than normal summer, plus the impact of two major hurricanes (Katrina and Rita) on natural gas production from the Gulf of Mexico, caused natural gas prices in the Rocky Mountain Region, and other parts of the country, to increase dramatically during the third and fourth quarters of 2005. During 2006, by contrast, record warm temperatures were observed during January and December of 2006 (both critical months for natural gas demand used for heating) and throughout the entire year. The U.S. National Climatic Data Center (a division of the National Oceanic and Atmospheric Administration) recently announced that 2006 was the warmest year in the United States in 112 years of record keeping. These record warm temperatures diminished demand for natural gas, and caused larger than normal inventories of natural gas in storage during 2006. As a result of the diminished demand due to warmer weather and high levels of natural gas in storage, natural gas prices declined during 2006, both nationally and in southwest Wyoming.

Because production exceeds local demand for natural gas, the Rocky Mountain Region is usually a net-exporter of natural gas. Historically, natural gas production in southwest Wyoming has sold at a discount relative to other U.S. natural gas production sources or market areas. These regional pricing differentials or discounts are typically referred to as "basis" or "basis differentials". The Company has seen significant basis differentials for its Wyoming production, versus the Henry Hub pricing reference point in south Louisiana in the past. This trend continued in 2006. As a result, the Company realized prices that were lower than those received by companies with natural gas production in other regions of the U.S. Increases in pipeline capacity to transport production from Rocky Mountain production areas to markets in the West in recent years have served to improve (i.e. lower) basis differentials for Wyoming natural gas production. (Examples include: Kern River Pipeline — in service May 2003; the Cheyenne Plains Pipeline — in service February 2005; and Rockies Express Pipeline expansion to Cheyenne, Wyoming placed into service on February 14, 2007). These expansions of pipeline export capacity have historically reduced but not eliminated the basis differential for natural gas prices in southwest Wyoming when compared to prices at the Henry Hub pricing reference point. There have been, from time to time, numerous other proposed pipeline projects that have been announced to transport Rockies and Wyoming natural gas production to markets.

During 2006, the Company continued to take action toward assuring that the pipeline infrastructure to move its natural gas supplies away from southwest Wyoming will be expanded to provide sufficient capacity to transport its natural gas production and to provide for reasonable basis differentials for its natural gas in the future. The Company agreed to become an anchor shipper on the proposed Rockies Express Pipeline project, sponsored by subsidiaries of Kinder Morgan, Conoco Phillips, and Sempra Energy. The Rockies Express Pipeline, if built as proposed, would be the largest natural gas transmission pipeline project of its type built in the United States in more than 20 years, beginning at the Opal Processing Plant in southwest Wyoming and traversing Wyoming and several other states to an ultimate terminus in eastern Ohio. This pipeline is projected to cover more than 1,800 miles and is contemplated to be a large-diameter (42”), high-pressure natural gas pipeline. The Rockies Express Pipeline, if built, will be an interstate pipeline and would therefore be subject to the jurisdiction of the United States Federal Energy Regulatory Commission (“FERC”).

On December 19, 2005, the Company entered into two Precedent Agreements (“Precedent Agreements”) with Rockies Express Pipeline, LLC (“REX”) and Entrega Gas Pipeline, LLC. The Precedent Agreements govern the parties through the design, regulatory process and construction of the pipeline facilities and, subject to certain conditions precedent, the Company will take firm transportation service, if and when the pipeline facilities are constructed. Commencing upon completion of the pipeline facilities, the Company’s commitment involves a capacity of 200,000 MMBtu per day of natural gas for a term of 10 years, and the Company will be obligated to pay REX certain demand charges related to its rights to hold this firm transportation capacity as an anchor shipper. Based on current assumptions, current projections regarding the cost of the expansion and the participation of other shippers in the expansion (noting specifically that these assumptions are likely to change materially), the Company currently projects that annual demand charges due may be approximately $70.0 million per year for the term of the contract, exclusive of fuel and surcharges. The Company’s Board of Directors approved the Precedent Agreements on February 6, 2006 and Kinder Morgan, as the managing member of REX, advised the Company of their final approval of the Precedent Agreements, and their intent to proceed with the construction of the Rockies Express Pipeline on February 28, 2006.

The pipeline facilities are currently anticipated to be completed in stages between 2008 and 2009. REX filed its application for a Certificate of Public Convenience and Necessity for the Rockies Express West Project (“REX-West”) with the FERC on May 31, 2006. The REX-West portion of the project is 713 miles of pipeline commencing at Cheyenne Hub (Weld County, CO) and ending in Audrain County, Missouri. The FERC issued a Preliminary Determination on Non-Environmental Issues related to the REX-West application on September 21, 2006, stating that, subject to certain conditions, REX’s proposals are in the public interest. This order did not consider or evaluate any environmental issues, which will be addressed in a subsequent FERC order, which is expected during 2007. FERC also issued a Draft Environmental Impact Statement on REX-West, on November 3, 2006. REX has indicated to the Company that, upon receipt of the final FERC order on environmental issues, construction of the REX-West portion of the project will commence. This is expected to occur early in the second quarter of 2007. The REX partners have indicated that they will file an application for a Certificate of Public Convenience and Necessity for the Rockies Express East segment (Missouri to Ohio) for the proposed project following receipt of the order approving the REX-West Certificate of Public Convenience and Necessity.

Although the Company is optimistic that the Rockies Express Pipeline project will receive the necessary regulatory approvals and be constructed in a timely manner, there are no assurances that the Rockies Express Pipeline will be built, nor are there any assurances that, if built, the pipeline will eliminate or reduce the basis differentials historically seen in its Wyoming production.

Oil Marketing

Through its wholly-owned subsidiary, Sino-American Energy Corporation, the Company markets its share of oil production from the 04/36 and 05/36 Blocks in Bohai Bay, China. In addition, the first two of its fields in the previously non-producing 05/36 Block, Bohai Bay, offshore China (CFD 12-1 and 12-1 South), began producing oil in the third quarter of 2006 along with the CFD 11-6 on the 04/36 Block.

The Company's Chinese oil production ("CFD crude") is sold on a tanker/cargo lifting basis. As the Company's share of inventories on the CFD fields' Floating Production Storage and Offloading Vessel ("FPSO") become sufficient to schedule a lifting (typically 200,000 — 300,000 barrels per cargo), the Company coordinates with the operator and its markets to lift a cargo. By necessity, the Company will, from time to time, carry inventories of crude oil to accommodate the lifting schedules for its share of oil from the FPSO. The Company may also, from time to time, find itself in an over-lifted position as well. Each of the partners in the CFD fields are responsible for the disposition of their respective shares of the CFD crude production. The operator of these fields manages the lifting schedule.

The Company has traditionally sold most of its share of the CFD crude production to an affiliate of its Chinese partner, Chinese National Offshore Oil Corporation ("CNOOC") China, Ltd., at prices that are derived from the Indonesian Crude Price ("ICP") Duri monthly average price. In 2006, CNOOC again purchased the majority of the Company's share of the CFD production. The Company sold some of its remaining share of the CFD crude production outside of China. The Company continues to assess its opportunities to market its share of the CFD crude production to other markets such as Taiwan, Korea, Japan, Malaysia, the United States and Singapore. The Company does not have any outstanding, uncollectible accounts for CFD crude oil sales as of December 31, 2006.

The CFD crude is a heavy, sweet crude oil, with an API gravity of approximately 19 degrees. The production from these first seven fields is from multiple productive reservoirs, which have variability in the quality of oil. Due to its quality and physical characteristics, refiners and other markets for the CFD crude oil typically expect to be able to purchase CFD crude at prices that are lower than light sweet crude oils like West Texas Intermediate or Brent. Oil produced and sold from the seven CFD fields is typically priced based upon the monthly official ICP for Duri field crude. The Duri crude, produced in Indonesia, is of similar quality to the CFD crude produced in the Bohai Bay area. The official ICP Duri price is a monthly weighted average of three, independent daily assessments of the price of Duri crude, reported by Platt's Asian Petroleum Price Index published by Seapac Services Limited, and RIM Intelligence Co. To the monthly official ICP Duri marker price, a premium or discount is added to reflect transportation and quality differentials for the CFD crude relative to the Duri marker crude. The premium or discount for the CFD crude (relative to the Duri price) is negotiated monthly between the Company and its partners, including CNOOC. During 2006, the premium or discount from the ICP Duri price ranged from a discount of approximately $10.00 USD to a premium of more than $1.00 USD.

Environmental Matters

In 1998, the U.S. Bureau of Land Management ("BLM") initiated a requirement for an Environmental Impact Statement ("EIS") for federal lands in the Pinedale Anticline area in the Green River Basin. The Company also co-owns leases on state and privately owned lands in the vicinity of the Pinedale Anticline that do not fall under the federal jurisdiction of the BLM and are not subject to the EIS requirement. An EIS evaluates the effects that an industry's activities will have on the environment in which the activity is proposed. This EIS encompasses the area north of the Jonah Field, including the Pinedale Anticline, which is where most of the Company's exploration and development is taking place. This environmental study includes an analysis of the geological and reservoir characteristics of the area plus the necessary environmental studies related to wildlife, surface use, socio-economic and air quality issues. On July 27, 2000, the BLM issued its Record of Decision ("ROD") with respect to the final EIS. The ROD/EIS allows for the drilling of 700 producing surface locations within the area covered by the EIS, but does not authorize the drilling of particular wells. Ultra must submit applications to the BLM's Pinedale field manager for permits to drill and other required authorizations, such as rights-of-way for pipelines, for the drilling of each specific well or particular pipeline location. Development activities in the Pinedale Anticline area, as on all federal leaseholds, remain subject to regulatory agency approval. In making its determination on whether to approve specific drilling or development activities, the BLM applies the requirements outlined in the ROD/EIS.

The ROD/EIS imposes limitations and restrictions on activities in the Pinedale Anticline area, including limits on winter drilling and completion activity, proposes mitigation guidelines, standard practices for industry activities and best management practices for sensitive areas. The ROD/EIS also provides for annual reviews to compare actual environmental impacts to the environmental impacts estimated in the EIS and provides for adjustments to mitigate such impacts, if necessary. The review team is comprised of operators, local residents and other affected persons. The Company cannot predict if or how these changes may affect permitting, development and compliance under the ROD/EIS. The BLM's field manager may also impose additional limitations and mitigation measures as are deemed reasonably necessary to mitigate the impact of drilling and production operations in the area.

As of December 31, 2006, the Company had approximately 130 well locations that both the BLM and the WOGCC have approved permits to drill on Company operated federal leases in the Pinedale Anticline and Jonah field areas.

To date, the Company has expended significant resources in order to satisfy applicable environmental laws and regulations in the Pinedale Anticline area and other areas of operation under the jurisdiction of the BLM. The Company's future costs of complying with these regulations may continue to be substantial. Further, any additional limitations and mitigation measures could further increase production costs, delay exploration, development and production activities or curtail exploration, development and production activities altogether.

In August 1999, the BLM required an Environmental Assessment ("EA") for the potential increased density drilling in the Jonah Field area. An EA is a more limited environmental study than that conducted under an EIS. The EA was required to address the potential environmental impacts of developing the field on a well density of two wells per 80-acre drilling and spacing unit as opposed to the one well per 80-acre drilling and spacing unit as was approved in the initial Jonah field EIS approved in 1998. The new EA was completed in June 2000. With the approval of this EA and the earlier approval by the WOGCC for drilling of two wells per 80-acre drilling and spacing unit, the Company was permitted to drill infill wells at this well density on the 2,160 gross (1,322 net) acres then owned by the Company in the Jonah field. Prior to these approvals, the Company had drilled 21 gross (7.7 net) wells in the field. Since the increased density approvals, the Company has drilled an additional 22 gross (14.0 net) wells in the field. All 43 wells drilled by Ultra in the Jonah field have been productive. Subsequently, various other operators have received approval for the drilling of increased density wells in pilot areas at well densities ranging from four wells per 80-acre drilling and spacing unit to sixteen wells per drilling and spacing unit. Results of all of these pilot projects were utilized in acquiring approval from the WOGCC in November 2004 to increase the overall density of development for the Jonah Field to eight wells per 80-acre drilling and spacing unit.

The BLM conducted a new EIS covering the Jonah field to assess the impact of increased density development and define the parameters under which this increased density development will be allowed to proceed. The draft EIS was made available in February 2005 and the final ROD was issued on March 14, 2006. Key components of the ROD approval require an annual operations plan that includes all previous year activity including the number of wells drilled, total new surface disturbance by well pads, roads, and pipelines, and current status of all reclamation activity. Also required is a plan of development for the upcoming year reflecting the planned number of wells to be drilled and an estimate of new surface disturbance and reclamation activity. Other components include a drilling rig forecast, emission reduction report, annual water well monitoring reports, a three-year operational forecast and the use of flareless-completion technology to reduce noise, visual impacts and air emissions, including greenhouse gases as well as other monitoring and mitigation measures described in the BLM ROD. As of December 31, 2006, Ultra had two rigs operating within the area of approval.

During 2003, 2004 and 2005, Ultra and other operators in the Pinedale field received approval from the WOGCC to drill increased density pilot project wells in several areas across the Pinedale field. These pilot projects are designed to test the feasibility of developing this field in well densities greater than the currently approved one well per 40-acres. The results of some of this work led to the WOGCC in July 2004 approving the development of the northern portion of the anticline on two wells per 40-acre density. The acreage is operated by Questar Exploration and Production Company ("Questar"), a working interest partner of the Company, and the Company owns a working interest in the majority of this acreage. This approval covers approximately 14,432 gross acres. Since this time, additional increased density pilot wells have been drilled by Ultra and others on the pilot areas within the Pinedale field. Based on the data gathered through these pilot projects, the WOGCC approved several additional Increased Density Applications during 2005. In August 2005, approval was granted for development of a significant portion of the northern portion of the Pinedale field for drilling on four wells per 40-acre density. This approval covers approximately 11,256 gross acres in which Ultra owns an interest and are operated by Questar. In November 2005, approval was granted for development of a significant portion of the central Pinedale field and surrounding area on a two wells per 40-acre density. This approval covers approximately 23,816 gross acres in which Ultra owns an interest. Ultra operates the majority of the acreage covered by this approval. During 2006, Ultra and other operators in the Pinedale field received approval from the WOGCC to drill increased density wells in two new areas of the Pinedale field. These two areas cover a total of 10,043 acres and will permit the development of the Lance Pool in these areas at the equivalent of one well per 10-acres. Of the 1,043 locations now available in these two areas, the Company owns an interest in 947 of them and will be the operator of 724 locations. With this approval nearly 50% of the productive area of the Pinedale field has now been approved by the WOGCC for drilling at the equivalent of 10-acre density. An additional 30% has been approved for drilling at equivalent 20-acre density with the balance still under the state wide 40-acre well density rules. Further drilling and testing within the areas approved for increased density continues and the results of these are being evaluated to determine the appropriate course of action as to the overall development strategy for the Pinedale field and the ultimate need for future increases in development density.

In April 2004, Questar asked the BLM to modify winter access restrictions to allow operations on three active pads with two drilling rigs per pad during the winter restriction period. This request required an EA to weigh the negative impacts of winter activity relative to the extensive mitigation measures proposed by Questar. On November 9, 2004, Questar received approval in the form of a “Finding of No Significant Impact” (“FONSI”) from the BLM to phase in over the next year the proposed year-round drilling program which allowed two drilling rigs on one pad during the winter of 2004-2005. Questar’s proposed mitigation measures included construction of a water and condensate gathering system during the summer of 2005. Questar’s proposal allows six rigs to operate from three active pads beginning in the winter of 2005-2006 through the winter of 2013-2014 once implementation of the proposed mitigation measures is complete.

The BLM approved Questar’s proposal after considering extensive input from the participating agencies received during a public comment process. Key components of the approval are: 1) one pad with two drilling rigs during the winter of 2004-2005; 2) three pads with two drilling rigs per pad in the winter of 2005-2006 and thereafter through the winter of 2013-2014; 3) activities during the May-November period will continue to be governed by the original Pinedale Anticline EIS; 4) directional drilling with up to 16 wells per pad resulting in only one-third of the drilling phase surface disturbance contemplated under the original EIS; 5) construction of a produced water and condensate gathering system in 2005; 6) funding for continued monitoring of mule deer and other critical wildlife for the duration of development activity; 7) use of flareless-completion technology to reduce noise, air and visual pollution during well-completion operations; 8) funding for air-quality monitoring; and 9) wildlife habitat enhancement as well as other monitoring and mitigation measures described in the BLM decision record.

Questar is proceeding with the winter drilling program as proposed. Currently there are six Questar operated drilling rigs operating within the area of approval, two rigs on each of three separate winter pads. These wells will be drilled to total depth, logged and cased during the winter restriction period with completion activity to commence in the spring with the lifting of the normal seasonal wildlife restrictions.

In early 2005, Ultra, along with Anschutz and Shell (“Proponents”) proposed a winter access demonstration project to the BLM for the Mesa area of the Pinedale field. This area is normally subject to the winter big game stipulation which prohibits drilling and completion activities in the area from November 15th until April 30th. Under the terms of the proposal, the Proponents would be able to operate a total of six rigs, two each on three different winter pads. During this winter demonstration project, the Proponents employed innovative technologies and practices for operations to provide a more beneficial alternative to the current wildlife restrictions. Upon successful completion of the winter demonstration project, the Proponents intend to apply the operations principles demonstrated to implement a long-term development plan that will result in substantially less impact to wildlife, habitat, and local communities than what is allowed under the current Pinedale Anticline Project Area (“PAPA”) ROD while providing assurance of year-round access from the BLM to permit the implementation of a comprehensive development scenario for the Pinedale field. An EA was conducted by the BLM to evaluate the winter demonstration project proposal and associated impacts and the Proponents received approval in the form of a FONSI ruling from the BLM in September 2005. The Proponents began activities in the winter demonstration project in November 2005. The FONSI ruling includes several conditions of approval requiring monitoring and mitigation of impacts on wildlife and monitoring and mitigation of rig engine emissions and noise levels associated with project drilling activities. Ultra operated four rigs during the 2005-2006 winter demonstration project and met its commitments under the terms of the approval. The wells were drilled to total depth, logged and cased during winter restriction period. Completion activity commenced in the spring of 2006 with the lifting of normal seasonal wildlife restrictions.

Subsequent to the FONSI ruling allowing implementation of the winter demonstration project, the Proponents submitted a development proposal for the Pinedale field which includes broad application of operations principles being evaluated in the demonstration project area. The Proponents entered into a memorandum of understanding with the BLM to commence the preparation of a Supplemental Environmental Impact Statement ("SEIS") for year-round access in the Pinedale field.

The SEIS process is proceeding and impacts the development proposal that will be analyzed to assess alternative considerations and mitigation requirements that should be considered as alternatives to those included in the proposal or in addition to those measures now proposed. The proposed action includes commitments to reduce surface disturbance by utilizing fewer overall pads and drilling more directional wells than called for in the PAPA ROD. Also, if approved, the Proponents' proposal commits to reduced air emissions. The Proponents have proposed to apply technology to drilling rig engines to reduce emissions, to reduce vehicle traffic by installing a liquids gathering system as appropriate in the field, and by expanding the use of telemetry to reduce production operations' traffic requirements. The Proponents have also proposed additional monitoring to assess benefits of mitigation activities on the impacts of development activities on the wildlife in the project area. The proposal commits to 3:1 offsite mitigation measures should the monitoring indicate it is warranted. If approved, the Proponents' proposal commits to reduced reserve pit use and to accelerated surface reclamation. The draft SEIS ("DSEIS") was sent out for public comment on December 15, 2006. The closing date for public comment is anticipated for March 15, 2007 and the final ROD is anticipated in the summer of 2007.

Development activities in the Pennsylvania area also remain subject to regulatory agency approval and compliance with performance standards. Ultra must submit applications to the Pennsylvania Department of Environmental Protection ("DEP") for permits to drill and for other required authorizations, such as rights-of-way for pipelines for each specific well or pipeline location. In February 2006, the Company submitted a general permit for construction to the Pennsylvania DEP for the Marshlands Pipeline PL-101 gathering line in Tioga County and the associated Preparedness, Prevention, Contingency Plan. As of December 31, 2006, there was one rig operating in the permit area and the Company had approximately one additional well location with respect to which Pennsylvania DEP has approved permits to drill on Company-operated leases in the Pennsylvania area.

In September 2002, the Company received the "Oil and Gas Wildlife Stewardship" award from the Wyoming Game and Fish Department in recognition of its contribution to wildlife management in the Pinedale area. During 2001, the Company received the "Agency/Corporation of the Year" award from the Wyoming Wildlife Federation and the "Regional Administrator's Award for Environmental Achievement" from the U.S. Environmental Protection Agency.

Regulation

Oil and Gas Regulation

The availability of a ready market for oil and natural gas production depends upon numerous factors beyond the Company's control. These factors may include, among other things, state and federal regulation of oil and natural gas production and transportation, as well as regulations governing environmental quality and pollution control, state limits on allowable rates of production by a well or proration unit, the amount of oil and natural gas available for sale, the availability of adequate pipeline and other transportation and processing facilities and the marketing of competitive fuels. For example, a productive natural gas well may be "shut-in" because of a lack of an available natural gas pipeline in the areas in which the Company may conduct operations. State and federal regulations are generally intended to prevent waste of oil and natural gas, protect rights to produce oil and natural gas between owners in a common reservoir, control the amount of oil and natural gas produced by assigning allowable rates of production and control contamination of the environment. Pipelines and natural gas plants are also subject to the jurisdiction of various federal, state and local agencies.

The Company's sales of natural gas are affected by the availability, terms and costs of transportation both in the gathering systems that transport the natural gas from the wellhead to the interstate pipelines and in the interstate pipelines themselves. The rates, terms and conditions applicable to the interstate transportation of natural gas by pipelines are regulated by the FERC under the Natural Gas Act, as well as under Section 311 of the Natural Gas Policy Act. Since 1985, the FERC has implemented regulations intended to increase competition within the natural gas industry by making natural gas transportation more accessible to natural gas buyers and sellers on an open-access, non-discriminatory basis. On February 25, 2000, the FERC issued a statement of policy and a final rule concerning alternatives to its traditional cost-of-service rate-making methodology to establish the rates interstate pipelines may charge for services. The final rule revises the FERC's pricing policy and current regulatory framework to improve the efficiency of the market and further enhance competition in natural gas markets. The FERC is also considering a number of regulatory initiatives that could affect the terms and costs of interstate transportation of natural gas by interstate pipelines on behalf of natural gas shippers, including policy inquiries about natural gas quality and interchangeability, selective discounting of transportation services by pipelines to shippers, and proposed rules governing pipeline creditworthiness and collateral standards. Because these regulatory initiatives have not been made final, the approach the FERC will take and the potential impact on natural gas suppliers remain unclear.

The Company's sales of oil are also affected by the availability, terms and costs of transportation. The rates, terms, and conditions applicable to the interstate transportation of oil by pipelines are regulated by the FERC under the Interstate Commerce Act. The FERC has implemented a simplified and generally applicable ratemaking methodology for interstate oil pipelines to fulfill the requirements of Title XVIII of the Energy Policy Act of 1992 comprised of an indexing system to establish ceilings on interstate oil pipeline rates.

If the Company conducts operations on federal, tribal or state lands, such operations must comply with numerous regulatory restrictions, including various operational requirements and restrictions, nondiscrimination statutes and royalty and related valuation requirements. In addition, some operations must be conducted pursuant to certain on-site security regulations, bonding requirements and applicable permits issued by the BLM or Minerals Management Service, Bureau of Indian Affairs, tribal or other applicable federal, state and/or Indian Tribal agencies.

The Mineral Leasing Act of 1920 ("Mineral Act") prohibits direct or indirect ownership of any interest in federal onshore oil and gas leases by a foreign citizen of a country that denies "similar or like privileges" to citizens of the United States. Such restrictions on citizens of a non-reciprocal country include ownership or holding or controlling stock in a corporation that holds a federal onshore oil and gas lease. If this restriction is violated, the corporation's lease can be canceled in a proceeding instituted by the United States Attorney General. Although the regulations of the BLM (which administers the Mineral Act) provide for agency designations of non-reciprocal countries, there are presently no such designations in effect. The Company owns interests in numerous federal onshore oil and gas leases. It is possible that holders of the Company's equity interests may be citizens of foreign countries, which could be determined to be citizens of a non-reciprocal country under the Mineral Act.

See *"Risk Factors"* for a discussion of the risks involved in our international operations.

Environmental Regulations

General. The Company's activities in the United States are subject to existing federal, state and local laws and regulations governing environmental quality, oil spills and pollution control. Activities in China are subject to the laws and regulations of China. It is anticipated that, absent the occurrence of an extraordinary event, compliance with existing federal, state and local laws, rules and regulations governing the release of materials in the environment or otherwise relating to the protection of the environment, will not have a material effect upon the Company's operations, capital expenditures, earnings or competitive position.

The Company's exploration, drilling and production activities from wells and natural gas facilities, including the operation and construction of pipelines, plants and other facilities for transporting, processing, treating or storing oil, natural gas and other products, are subject to stringent environmental regulation by state and federal authorities, including the Environmental Protection Agency ("EPA"). Such regulation can increase the cost of planning, designing, installing and operating such facilities. Usually, the EPA regulatory requirements relate to water and air pollution control measures.

Solid and Hazardous Waste. The Company has previously owned or leased and currently owns or leases, numerous properties that have been used for the exploration and production of oil and natural gas for many years. Although the Company utilized standard operating and disposal practices, hydrocarbons or other solid wastes may have been disposed of or released on or under such properties on or under locations where such wastes have been taken for disposal. In addition, many of these properties are or have been operated by third parties over whom the Company has no control, nor has ever had control as to such entities' treatment of hydrocarbons or other wastes or the manner in which such substances may have been disposed of or released. State and federal laws applicable to oil and natural gas wastes and properties have gradually become stricter over time. As the law evolves, the Company could be required to remediate property, including ground water, containing or impacted by previously disposed wastes (including wastes disposed of or released by prior owners or operators) or to perform remedial plugging operations to prevent future, or mitigate existing contamination.

The Company may generate wastes, including hazardous wastes that are subject to the federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. The EPA and various state agencies have limited the disposal options for certain wastes, including wastes designated as hazardous under the RCRA and state analogs ("Hazardous Wastes") and is considering adopting stricter disposal standards for non-hazardous wastes. Furthermore, certain wastes generated by the Company's oil and natural gas operations that are currently exempt from treatment as Hazardous Wastes may in the future be designated as Hazardous Wastes under the RCRA or other applicable statutes, and therefore be subject to more rigorous and costly operating and disposal requirements.

Superfund. The federal Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, generally imposes joint and several liability for costs of investigation and remediation and for natural resource damages, without regard to fault or the legality of the original conduct, on certain classes of persons with respect to the release into the environment of substances designated under CERCLA as hazardous substances ("Hazardous Substances"). These classes of persons, or so-called potentially responsible parties ("PRP"), include current and certain past owners and operators of a facility where there has been a release or threat of release of a Hazardous Substance and persons who disposed of or arranged for the disposal of the Hazardous Substances found at such a facility. CERCLA also authorizes the EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the PRP the costs of such action. Although CERCLA generally exempts "petroleum" from the definition of Hazardous Substance, in the course of its operations, the Company has generated and will generate wastes that fall within CERCLA's definition of Hazardous Substances. The Company may also be an owner or operator of facilities on which Hazardous Substances have been released. The Company may be responsible under CERCLA for all or part of the costs to clean up facilities at which such substances have been released and for natural resource damages. To its knowledge, the Company has not been named a PRP under CERCLA nor have any prior owners or operators of its properties been named as PRP's related to their ownership or operation of such property.

National Environmental Policy Act. The federal National Environmental Policy Act provides that, for those federal actions that are major federal actions significantly affecting the quality of the human environment, the federal agency taking such action must follow certain steps in evaluating the environmental impacts of the federal action. This evaluation generally takes the form of an EIS. In the EIS, the agency is required to evaluate alternatives to the proposed action and the environmental impacts of such alternatives. Actions such as drilling on federal lands, to the extent the drilling requires federal approval, likely trigger the requirements of the National Environmental Policy Act, with few exceptions. Certain of the Company's activities may trigger these requirements. The requirements of the National Environmental Policy Act may result in increased costs, significant delays and the imposition of restrictions or obligations, including but not limited to the restricting or prohibiting of drilling on a company's activities.

Oil Pollution Act. The Oil Pollution Act of 1990 ("OPA"), which amends and augments oil spill provisions of the Clean Water Act ("CWA"), imposes certain duties and liabilities on certain "responsible parties" related to the prevention of oil spills and damages resulting from such spills in or threatening United States waters or adjoining shorelines. A liable "responsible party" includes the owner or operator of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge or, in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. The OPA assigns joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses and limitations exist to the liability imposed by OPA, they are limited. In the event of an oil discharge or substantial threat of discharge, a company could be liable for costs and damages.

Air Emissions. The Company's operations are subject to local, state and federal regulations for the control of emissions from sources of air pollution. Federal and state laws require new and modified sources of air pollutants to obtain permits prior to commencing construction. Major sources of air pollutants are subject to stringent, federally imposed requirements such as obtaining permits. Other federal and state laws designed to control hazardous (toxic) air pollutants, might require installation of additional controls. Administrative enforcement agencies can bring actions for failure to strictly comply with air pollution regulations or permits and generally enforce compliance by imposing monetary fines and identified deficiencies. Alternatively, regulatory agencies can file lawsuits for civil penalties or the use of certain air emission sources for construction, modification or operations.

Clean Water Act. The CWA restricts the discharge of wastes, including produced waters and other oil and natural gas wastes, into waters of the United States, a term broadly defined. These controls have become more stringent over the years, and it is probable that additional restrictions will be imposed in the future. Permits must be obtained to discharge pollutants into federal waters. The CWA provides for civil, criminal and administrative penalties for unauthorized discharges of pollutants and of oil and hazardous substances. It imposes substantial potential liability for the costs of removal or remediation associated with discharges of oil or hazardous substances. State laws governing discharges to water also provide varying civil, criminal and administrative penalties and impose liabilities in the case of a discharge of petroleum or its derivatives, or other hazardous substances, into state waters. In addition, the EPA has promulgated regulations that may require permits to discharge storm water runoff, including discharges associated with construction activities. In the event of an unauthorized discharge of wastes, a company may be liable for penalties and costs.

Endangered Species Act and the Migratory Bird Treaty Act. The Endangered Species Act ("ESA") was established to provide a means to conserve the ecosystems upon which endangered and threatened species depend, to provide a program for conservation of these endangered and threatened species, and to take the appropriate steps that are necessary to bring any endangered or threatened species to the point where measures provided for in the ESA are no longer necessary. The Migratory Bird Treaty Act decreed that all migratory birds and their parts (including eggs, nests, and feathers) were fully protected. The Company conducts operations on federal oil and natural gas leases that have species, such as raptors that are listed as threatened or endangered and also sage grouse or other sensitive species, that potentially could be listed as threatened or endangered under the ESA. If a species is listed as threatened or endangered, the U.S. Fish and Wildlife Service must also designate the species' critical habitat and suitable habitat as part of the effort to ensure survival of the species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit land access for oil and natural gas development. If a company were to have a portion of its leases designated as critical or suitable habitat, it may adversely impact the value of the affected leases.

OSHA and other Regulations. The Company is subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes require a company to organize and/or disclose information about hazardous materials used or produced in its operations.

The Company believes that it is in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on the Company.

Employees

As of December 31, 2006, the Company had 68 full-time employees, including officers.

Item 1A. ***Risk Factors.***

There are inherent limitations in all control systems and failure of our controls and procedures to detect error or fraud could seriously harm our business and results of operations.

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our internal controls and disclosure controls will prevent all possible error and all fraud. 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. In addition, the design of a control system must reflect the fact that there are resource constraints and the benefit of controls must be relative to their costs. Because of the inherent limitations in all control systems, no evaluation of our controls can provide absolute assurance that all control issues and instances of fraud, if any, in our Company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Further, controls can be circumvented by the individual acts of some persons or by collusion of two or more persons. The design of any system of controls is based in part upon the likelihood of future events, and there can be no assurance that any design will succeed in achieving its intended goals under all potential future conditions. Over time, a control may become inadequate because of changes in conditions or the degree of compliance with its policies or procedures may deteriorate. Because of inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur without detection.

Our reserve estimates may turn out to be incorrect if the assumptions upon which these estimates are based are inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

There are numerous uncertainties inherent in estimating quantities of proved reserves and projected future rates of production and timing of development expenditures, including many factors beyond our control. The reserve data and standardized measures set forth herein represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers often vary. In addition, results of drilling, testing and production data acquired subsequent to the date of an estimate may justify revising such estimates. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. Further, the estimated future net revenues from proved reserves and the present value thereof are based upon certain assumptions, including geologic success, prices, future production levels and costs that may not prove correct over time. Predictions of future production levels are subject to great uncertainty, and the meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they are based. Historically, oil and natural gas prices have fluctuated widely.

Competitive industry conditions may negatively affect our ability to conduct operations.

We compete with numerous other companies in virtually all facets of our business. The competitors in development, exploration, acquisitions and production include major integrated oil and natural gas companies as well as numerous independents, including many that have significantly greater resources. Therefore, competitors may be able to pay more for desirable leases and evaluate, bid for and purchase a greater number of properties or prospects than the financial or personnel resources that our Company can permit. Our ability to increase reserves in the future will be dependent on our ability to select and acquire suitable prospects for future exploration and development.

Factors that affect our ability to compete in the marketplace include:

- our access to the capital necessary to drill wells and acquire properties;
- our ability to acquire and analyze seismic, geological and other information relating to a property;

- our ability to retain the personnel necessary to properly evaluate seismic and other information relating to a property; and
- our ability to access platforms and pipelines, and the locations of facilities used to produce and transport oil and natural gas production.

Factors beyond our control affect our ability to effectively market production and may ultimately affect our financial results.

The ability to market oil and natural gas depends on numerous factors beyond our control. These factors include:

- the extent of domestic production and imports of oil and natural gas;
- the availability of pipeline capacity;
- the proximity of natural gas production to those natural gas pipelines;
- the effects of inclement weather;
- the demand for oil and natural gas by utilities and other end users;
- the availability of alternative fuel sources;
- state and federal regulations of oil and natural gas marketing; and
- federal regulation of natural gas sold or transported in interstate commerce.

Because of these factors, we may be unable to market all of our oil and natural gas that we produce, including oil and natural gas that may be produced from the Bohai Bay properties in China. In addition, we may be unable to obtain favorable prices for the oil and natural gas we produce.

We may experience a temporary decline in revenues if we lose one of our significant customers.

A significant customer as used herein is one that individually accounts for 10% or more of our total natural gas or oil sales. In 2006, we had one significant customer for our CFD Chinese crude oil: — CNOOC, and three significant customers for our natural gas production — Southern California Gas Company, J. Aron (Goldman Sachs), and Sempra Energy Trading. To the extent these or any other significant customer reduces the volume of its oil or natural gas purchases from us, we could experience a temporary interruption in sales of, or a lower price for, our oil and natural gas.

A decrease in oil and natural gas prices may adversely affect our results of operations and financial condition.

Our revenues are determined, to a large degree, by prevailing natural gas prices for production situated in the Rocky Mountain Region of the United States, specifically, southwest Wyoming, as well as prevailing prices for crude oil produced in the Bohai Bay region of China. Energy commodity prices in general, and our regional prices in particular, have been historically highly volatile, and such high levels of volatility are expected to continue in the future. We cannot accurately predict the market prices that we will receive for the sale of our natural gas, condensate, or oil production.

Oil and natural gas prices are subject to a variety of additional factors beyond our control, such as large fluctuations in oil and natural gas prices in response to relatively minor changes in the supply of and demand for oil and natural gas and market uncertainty. These factors include but are not limited to weather conditions in the United States, the condition of the United States economy, the actions of the Organization of Petroleum Exporting Countries, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and natural gas, the price of foreign oil and natural gas imports and the availability of alternate fuel sources and transportation interruption. Any substantial and extended decline in the price of oil or natural gas could have an adverse effect on the carrying value of our proved reserves, borrowing capacity, our ability to obtain additional capital, and the Company’s revenues, profitability and cash flows from operations.

Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisition and divestiture and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

A price decrease may more adversely affect the price received for our Wyoming production than production in other U.S. regions.

Natural gas prices in the southwest Wyoming region are critical to our business. The market price for this natural gas differs from the market indices for natural gas in the Gulf Coast region of the United States due potentially to insufficient pipeline capacity and/or low demand during certain months of the year for natural gas in the Rocky Mountain region of the United States. Therefore, a price decrease may more adversely affect the price received for our Wyoming production than production in the other U.S. regions. There have been, from time to time, numerous proposed pipeline projects, including the Rockies Express Pipeline, that have been announced to transport Rockies' and Wyoming natural gas production to markets. There can be no assurance that such infrastructures will be built or that if built, they would prevent large basis differentials from occurring in the future.

Compliance with environmental and other government regulations could be costly and could negatively impact our production.

Our operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may:

- require that we acquire permits before commencing drilling;
- restrict the substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on protected areas such as wetlands or wilderness areas;
- require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells; and
- require governmental approval of the overall development plan prior to the start of development of fields in China.

Under these laws and regulations, we could be liable for personal injury and clean-up costs and other environmental and property damages, as well as administrative, civil and criminal penalties. We maintain limited insurance coverage for sudden and accidental environmental damages, but do not maintain insurance coverage for the full potential liability that could be caused by sudden and accidental environmental damages. Accordingly, we may be subject to liability or may be required to cease production from properties in the event of environmental damages.

A significant percentage of our United States operations are conducted on federal lands. These operations are subject to a variety of on-site security regulations as well as other permits and authorizations issued by the BLM, the Wyoming Department of Environmental Quality and other federal agencies. A portion of our acreage is affected by winter lease stipulations that prohibit exploration, drilling and completing activities generally from November 15th to April 30th, but allow production activities all year round. To drill wells in Wyoming, we are required to file an Application for Permit to Drill with the WOGCC. Drilling on acreage controlled by the federal government requires the filing of a similar application with the BLM. These permitting requirements may adversely affect our ability to complete our drilling program at the cost and in the time period anticipated. On large-scale projects, lessees may be required to perform an EIS to assess the environmental impact of potential development, which can delay project implementation and/or result in the imposition of environmental restrictions that could have a material impact on cost or scope.

We may not be able to replace our reserves or generate cash flows if we are unable to raise capital. We will be required to make substantial capital expenditures to develop our existing reserves and to discover new oil and gas reserves.

Our ability to continue exploration and development of our properties and to replace reserves may be dependent upon our ability to continue to raise significant additional financing, including debt financing or obtain other potential arrangements with industry partners in lieu of raising financing. Any arrangements that may be entered into could be expensive to us. There can be no assurance that we will be able to raise additional capital in light of factors such as the market demand for our securities, the state of financial markets for independent oil and gas companies (including the markets for debt), oil and natural gas prices and general market conditions. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources" for a discussion of our capital budget.

We expect to continue using our bank credit facility to borrow funds to supplement our available cash flow. The amount we may borrow under the credit facility may not exceed a borrowing base determined by the lenders based on their projections of our future production, future production costs and taxes, commodity prices and other factors. We cannot control the assumptions the lenders use to calculate the borrowing base. The lenders may, without our consent, adjust the borrowing base at any time. If our borrowings under the credit facility exceed the borrowing base, the lenders may require that we repay the excess borrowing. If this occurred, we may have to sell assets or seek financing from other sources. We can make no assurances that we would be successful in selling assets or arranging substitute financing. For a description of the bank credit facility and its principal terms and conditions, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources."

Our operations may be interrupted by severe weather or drilling restrictions, particularly in the Rocky Mountain region.

Our operations are conducted primarily in the Rocky Mountain region of the United States. The weather in this area can be extreme and can cause interruption in our exploration and production operations. Severe weather can result in damage to our facilities entailing longer operational interruptions and significant capital investment. Likewise, our Rocky Mountain operations are subject to disruption from winter storms and severe cold, which can limit operations involving fluids and impair access to our facilities. A portion of our acreage is affected by winter lease stipulations that prohibit drilling and completing activities from November 15th to April 30th, but allow production activities all year round.

Our focus on exploration projects increases the risks inherent in our oil and gas activities.

We have historically invested a significant portion of our capital budget in drilling exploratory wells in search of unproved oil and gas reserves. We cannot be certain that these exploratory wells will be productive or that we will recover all or any portion of our investments. To increase the chances for exploratory success, we often invest in seismic or other geoscience data to assist us in identifying potential drilling objectives. Additionally, the cost of drilling, completing and testing exploratory wells is often uncertain at the time of our initial investment. Depending on complications encountered while drilling, the final cost of the well may significantly exceed our original estimate. We use the full cost method of accounting for exploration and development activities as defined by the SEC. Under this method of accounting, the costs of unsuccessful, as well as successful, exploration and development activities are capitalized as properties and equipment and are then depleted using the unit of production method based on our proved reserves.

Unless we are able to replace reserves which we have produced, our cash flows and production will decrease over time.

Our future success depends on our ability to find, develop and acquire additional oil and gas reserves that are economically recoverable. Without successful exploration, development or acquisition activities, our reserves and production will decline. We can give no assurance that we will be able to find, develop or acquire additional reserves at acceptable costs.

We are exposed to operating hazards and uninsured risks that could adversely impact our results of operations and cash flow.

The oil and natural gas business involves a variety of operating risks, including fire, explosion, pipe failure, casing collapse, abnormally pressured formations, and environmental hazards such as oil spills, natural gas leaks, and discharges of toxic gases. The occurrence of any of these events with respect to any property we own or operate (in whole or in part) could have a material adverse impact on us. We and the operators of our properties maintain insurance in accordance with customary industry practices and in amounts that management believes to be reasonable. However, insurance coverage is not always economically feasible and is not obtained to cover all types of operational risks. The occurrence of a significant event that is not fully insured could have a material adverse effect on our financial condition.

There are risks associated with our drilling activity that could impact our results of operations.

Our oil and natural gas operations are subject to all of the risks and hazards typically associated with drilling for, and production and transportation of, oil and natural gas. These risks include the necessity of spending large amounts of money for identification and acquisition of properties and for drilling and completion of wells. In the drilling of exploratory or development wells, failures and losses may occur before any deposits of oil or natural gas are found. The presence of unanticipated pressure or irregularities in formations, blow-outs or accidents may cause such activity to be unsuccessful, resulting in a loss of our investment in such activity. If oil or natural gas is encountered, there can be no assurance that it can be produced in quantities sufficient to justify the cost of continuing such operations or that it can be marketed satisfactorily.

Our decision to drill a prospect is subject to a number of factors which may alter our drilling schedule or our plans to drill at all.

This report includes certain descriptions of our future drilling plans with respect to our prospects. A prospect is an area which our geoscientists have identified what they believe, based on available seismic and geological information, to be indications of hydrocarbons. Our prospects are in various stages of review. Whether or not we ultimately drill a prospect depends on the following factors:

- receipt of additional seismic data or reprocessing of existing data;
- material changes in oil or natural gas prices;
- the costs and availability of drilling equipment;
- success or failure of wells drilled in similar formations or which would use the same production facilities;
- availability and cost of capital;
- changes in the estimates of costs to drill or complete wells;
- the approval of partners to participate in the drilling or, in the case of CNOOC, approval of expenditures for budget purposes;
- our ability to attract other industry partners to acquire a portion of the working interest to reduce exposure to costs and drilling risks;
- decisions of our joint working interest owners; and
- the BLM’s interpretation of an EIS and the results of the permitting process.

We will continue to gather data about our prospects, and it is possible that additional information may cause us to alter our drilling schedule or determine that a prospect should not be pursued at all.

If oil and natural gas prices decrease, we may be required to take write-downs of the carrying value of our oil and gas properties.

We follow the full cost method of accounting for our oil and gas properties. A separate cost center is maintained for expenditures applicable to each country in which we conduct exploration and/or production activities. Under such method, the net book value of properties on a country-by-country basis, less related deferred income taxes, may not exceed a calculated "ceiling." The ceiling is the estimated after tax future net revenues from proved oil and gas properties, discounted at 10% per year. In calculating discounted future net revenues, oil and natural gas prices in effect at the time of the calculation are held constant, except for changes which are fixed and determinable by existing contracts. The net book value is compared to the ceiling on a quarterly basis. The excess, if any, of the net book value above the ceiling is required to be written off as an expense. Under SEC full cost accounting rules, any write-off recorded may not be reversed even if higher oil and natural gas prices increase the ceiling applicable to future periods. Future price decreases could result in reductions in the carrying value of such assets and an equivalent charge to earnings.

We are not the operator, and have limited influence over the operations, of our Bohai Bay properties.

Because we are not the operator and hold a minority interest, we cannot control the pace of exploration or development in the Bohai Bay properties or major decisions affecting the drilling of wells or the plan for development and production, although contract provisions give the Company certain consent rights in some matters. The operator's influence over these matters can affect the pace at which we spend money on this project. If the operator were to shift its focus from this project, the pace of development could slow down or stop altogether. On the other hand, if the operator were to decide to accelerate development of this project, we could be required to fund our share of costs at a faster pace than anticipated, which might exceed our ability to raise funds. If, because of this, we were unable to pay our share of costs, we could lose or be forced to sell our interest in the Bohai Bay properties or be forced to not participate in the exploration or development of specific prospects or fields, potentially diminishing the value of our Bohai Bay assets.

Political, economic or legal factors associated with our ownership of properties in China could impact our results of operations.

Ownership of property interests and production operations in areas outside the United States are subject to various risks inherent in foreign operations. These risks may include:

- loss of revenue, property and equipment as a result of expropriation, nationalization, war or insurrections;
- increases in taxes and governmental royalties;
- renegotiation of contracts with governmental entities and quasi-governmental agencies;
- change in laws and policies governing operations of foreign based companies;
- labor problems;
- other uncertainties arising out of foreign government sovereignty over its international operations; and
- currency restrictions and exchange rate fluctuations.

Tensions between China and its neighbors or various western countries, regional political or military disruption, changes in internal Chinese leadership, social or political disruptions within China, a downturn in the Chinese economy, or a change in Chinese laws or attitudes toward foreign investment could make China an unfavorable environment in which to invest. Although all the foreign interest owners in the Bohai Bay properties have the right to sell production in the world market, the regulation of the concession by China, and the likely participation by CNOOC as a large working interest owner, make Chinese internal and external affairs important to the investment in the Bohai Bay property. If any of these negative events were to occur, it could lead to a decision that there is an intolerable level of risk in continuing with the investment, or we may be unable to attract equity investors or lenders, or satisfy any then existing lenders.

In the event of a dispute arising from our foreign operations, we may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of courts in the United States or a potentially more favorable country.

In addition, our Chinese PSC terminates after 15-years of production, unless extended as provided for, which may be prior to the end of the productive life of the fields.

Our operations in China have special operational risks that may negatively affect the value of those assets.

Offshore operations, such as our Bohai Bay properties, are subject to a variety of operating risks specific to the marine environment, such as capsizing, collisions and/or loss from storms or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, we could incur substantial liabilities that could result in financial losses or failures. China has many regulations similar to those addressed in Item 1, Environmental Regulation, that may expose us to liability. Offshore projects, like the China field developments, are typically large, complex construction projects that are potentially subject to delays which may cause delays in achieving production and profitability.

Forward-Looking Statements

This report contains or incorporates by reference forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, Section 21E of the Securities Exchange Act of 1934 and the Private Securities Litigation Reform Act of 1995. All statements other than statements of historical facts included in this document, including without limitation, statements in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations regarding our financial position, estimated quantities and net present values of reserves, business strategy, plans and objectives of the Company's management for future operations, covenant compliance and those statements preceded by, followed by or that otherwise include the words "believe", "expects", "anticipates", "intends", "estimates", "projects", "target", "goal", "plans", "objective", "should", or similar expressions or variations on such expressions are forward-looking statements. The Company can give no assurances that the assumptions upon which such forward-looking statements are based will prove to be correct.

Forward-looking statements include statements regarding:

- our oil and natural gas reserve quantities, and the discounted present value of those reserves;
- the amount and nature of our capital expenditures;
- drilling of wells;
- the timing and amount of future production and operating costs;
- business strategies and plans of management; and
- prospect development and property acquisitions.

Some of the risks which could affect our future results and could cause results to differ materially from those expressed in our forward-looking statements include:

- general economic conditions;
- the volatility of oil and natural gas prices;
- the uncertainty of estimates of oil and natural gas reserves;
- the impact of competition;
- the availability and cost of seismic, drilling and other equipment;
- operating hazards inherent in the explorations for and production of oil and natural gas;
- difficulties encountered during the explorations for and production of oil and natural gas;

- difficulties encountered in delivering oil and natural gas to commercial markets;
- changes in customer demand and producers' supply;
- the uncertainty of our ability to attract capital;
- compliance with, or the effect of changes in, the extensive governmental regulations regarding the oil and natural gas business;
- actions of operators of our oil and natural gas properties; and
- weather conditions.

The information contained in this report, including the information set forth under the heading "Risk Factors," identifies additional factors that could affect our operating results and performance. We urge you to carefully consider these factors and the other cautionary statements in this report. Our forward-looking statements speak only as of the date made, and we have no obligation to update these forward-looking statements.

Item 1B. ***Unresolved Staff Comments.***

None.

Item 2. ***Properties.***

Location and Characteristics

The Company depends on oil and natural gas leases in Wyoming and Pennsylvania and two PSC's in China in order to explore for and produce oil and natural gas. The leases in Wyoming are primarily federal leases with 10-year lease terms until establishment of production. Production on a lease extends the lease terms until cessation of that production. There are 39 leases totaling approximately 65,345 gross (36,618 net) acres currently held by production ("HBP") in Wyoming. The HBP acreage includes all of the Company's leases held within the productive area of the Pinedale and Jonah fields. The leases in Pennsylvania are all from private individuals, typically with lease terms of five-years until establishment of production. Production on the Pennsylvania leases extends the lease terms until cessation of that production. There are approximately 320 gross (320 net) acres currently held by production in Pennsylvania. The China petroleum contracts extend for a maximum of 30-years and are divided into three periods; exploration, development and production. The exploration period is for approximately seven years and work is to be performed and expenditures are to be incurred to delineate the extent and amount of hydrocarbons, if any, for each block. The development period occurs when a field is discovered and commences on the date of approval of the Ministry of Energy. There is no limit on the time allowed to develop a field other than the combined maximum of 30-years. The production period of any oil and natural gas field in a block is a period of 15 consecutive years beginning on the date of commencement of commercial production from the field, unless extended. All of the Company's Chinese proved reserves are estimated to be recovered within the current license terms.

Green River Basin, Wyoming

As of December 31, 2006, the Company owned developed oil and natural gas leases totaling 15,067 gross (6,404 net) acres in the Green River Basin of Sublette County, Wyoming which represents 95% of the Company's total domestic developed net acreage. The Company owns undeveloped oil and natural gas leases totaling 132,850 gross (73,162 net) acres in the Green River Basin of Sublette County, Wyoming which represents 37% of the Company's total domestic undeveloped net acreage. The Company's acreage in the Green River Basin primarily covers the Pinedale field with several other undeveloped acreage blocks north and west of the Pinedale field as well as acreage in the Jonah field. Holding costs of leases in Wyoming not held by production were approximately $71,960 for the fiscal year ended December 31, 2006. The primary target on the Company's Wyoming acreage is the tight gas sands of the upper Cretaceous Lance Pool formation.

Exploratory Wells. During 2006, the Company participated in the drilling of a total of 44 gross (19.79 net) productive exploratory wells on the Green River Basin properties. At December 31, 2006, there were 29 gross (10.98 net) additional exploratory wells that commenced during the year that were either still drilling or had drilling operations suspended at a depth short of total depth and thus a determination of productive capability could not be made at year end.

Development Wells. During 2006, the Company participated in the drilling of 80 gross (38.44 net) productive development wells on the Green River Basin properties. At year-end 2006, there were 17 gross (6.66 net) additional development wells that commenced during 2006 and were either still drilling or had drilling operations suspended at a depth short of total depth. For purposes of this report, development wells are wells identified as proven, undeveloped locations by the Company's independent petroleum engineering firm, Netherland, Sewell & Associates, Inc., at the previous year end reserve evaluation. When drilled, these locations will be counted as development wells.

Bohai Bay, China

Block 04/36: The PSC covering this block became effective October 1, 1994. Negotiations with the Chinese government in 2005 resulted in an extension of the third exploration term to September 2007. Barring another extension, at that time, all acreage not under appraisal, development or production must be relinquished. The Company holds an 18.18% exploration interest in the exploration portion of the block and an 8.91% working interest in the CFD 11-1 and 11-2 and the CFD 11-3 and 11-5 fields. This block covers 413,623 gross (75,197 net) acres under the exploration phase and 40,377 gross (3,598 net) acres under development, or approximately 60% of the Company's total net international acreage.

Block 05/36: The PSC covering this block became effective March 1, 1996. Negotiations with CNOOC in early 2006 resulted in a two year extension of the third exploration term to February 28, 2008 when, barring an extension, all acreage not under appraisal, development or production must be relinquished. The Company holds a 23.03% exploration interest in this block which covers 218,079 gross (50,376 net) acres under the exploration phase and 15,221 gross (1,119) acres under development. This acreage constitutes approximately 40% of the Company's total net international acreage.

Block 04/36 and Block 05/36 Unitized Development: Three new fields, CFD 11-6 in the 04/36 Block and CFD 12-1 and 12-1S in the 05/36 Block came on production in 2006. Because the fields were located in close proximity, the Blocks were developed under a single development plan. Further, because two of the fields were located in the 05/36 Block and one was located in the 04/36 Block with different parties having different levels of interest in the two Blocks, the three fields were unitized and a Unitization Agreement was executed that assigned the Company a 7.82% working interest in the combined field unit.

Exploration/Appraisal Activity: In 2006, the Company participated in drilling 1 exploration well (0.23 net) which failed to find commercial quantities of oil. The primary target formations on the Blocks are the Upper and Lower Minghuazhen, Guantao and Dongying formations.

Development Activity: In July 2004, the Company began production at the CFD 11-1 and 11-2 fields on the 04/36 Block. Development drilling at these fields continued through mid-2006. As of December 31, 2006, the Company has participated in drilling a total of 58 production wells at the CFD 11-1 and 11-2 fields. In July 2005, the Company commenced production at the CFD 11-3 and 11-5 fields on the 04/36 Block. The Company has participated in drilling a total of 6 production wells at the CFD 11-3 and 11-5 fields. In late September 2006, the Company commenced production at the CFD 11-6, 12-1 and 12-1S fields. The Company has participated in drilling a total of 15 production wells at the CFD 11-6, 12-1 and 12-1S fields. The seven field production complex consists of 79 gross (6.89 net) production wells, six production platforms and an anchored FPSO vessel.

Upon declaration of commerciality of a field or area by CNOOC, the Company's share of all expenses within that area is decreased by 51%, with the participation of CNOOC. For example, the Company's 18.18% exploration interest is reduced to an 8.91% working interest in the fields on production in the 04/36 Block. Upon initiation of production, the sharing of production is determined by the language of the PSC which states that for each individual field: 1) a Chinese National Industrial Tax and Royalty are applied to 100% of the gross volumes of oil, 2) Lease Operating Expenses ("LOE") are then taken out of the remainder oil and 3) after these deductions, 62.5% of the remaining production stream is dedicated to Exploration and Development Cost Recovery for the participants. The Exploration Cost Recovery will be recovered without interest, while the Development Cost Recovery will be calculated with a fixed annual interest rate of 9% uplift, and 4) the remaining 37.5% of production goes to the "remainder oil" category which is divided into a "share oil" for CNOOC and an "allocable remainder oil" for the contractors determined by a sliding scale (determined by yearly production), "X" factor. Project profit is subject to a Chinese corporate tax. During 2006, the Chinese government levied the Petroleum Special Profits Tax which is dependent on the sales price of oil production.

On October 16, 2003, a 15-year contract, which provides for extension for up to an additional 10-years, was signed by the operator to lease an FPSO. The Company ratified the contract. The FPSO is a 110,000-150,000 dead weight ton, double hull FPSO with a 900,000-1,100,000 barrel storage capacity, a single point mooring and a processing plant capable of processing 60,000 barrels of oil per day (expandable to 80,000 barrels of oil per day). The FPSO service agreement calls for a day rate lease payment and a sliding scale per barrel payment that decreases based on cumulative barrels processed.

Pennsylvania

As of December 31, 2006, the Company owned developed oil and gas leases totaling 320 gross (320 net) acres in the Pennsylvania portion of the Appalachian Basin which represents 5% of the Company's total domestic developed net acreage. The Company owns undeveloped oil and gas leases totaling 232,691 gross (124,271 net) acres in this area which represents 63% of the Company's total domestic undeveloped net acreage. The Company's acreage in Pennsylvania covers the Marshlands prospect and several other prospects in the surrounding area. Holding costs of leases in Pennsylvania not held by production were approximately $248,017 for the fiscal year ended December 31, 2006.

Exploratory Wells. During the year ended December 31, 2005, the Company participated in the drilling and completion of a total of one gross (1.0 net) well which was completed as a field discovery from the Silurian Tuscarora formation. The well was placed into production during May of 2006. This well continues to produce at rates of approximately 5 MMcf of gas per day at flowing pressures over 1,100 psi casing pressure. During the year ended December 31, 2006, the Company also participated in the drilling of a total of 2 gross (1.125 net) exploratory wells on the Pennsylvania properties. One gross (.125 net) well was drilled to test the Oriskany sand and Marcellus shale sections and was being evaluated at December 31, 2006. One gross (1.0 net) well, to test the Trenton and Black River formations at the Marshlands prospect, was drilling at December 31, 2006. During 2006, on the newly acquired acreage position, the Company acquired a 3D seismic survey covering a large prospect area. Processing and interpretation of this data set is ongoing.

Oil and Gas Reserves

The following table sets forth the Company's quantities of domestic proved reserves, for the years ended December 31, 2006, 2005, and 2004 as estimated by independent petroleum engineers Netherland, Sewell & Associates, Inc. The table summarizes the Company's domestic proved reserves, the estimated future net revenues from these reserves and the standardized measure of discounted future net cash flows attributable thereto at December 31, 2006, 2005 and 2004. In accordance with Ultra's three-year planning and budgeting cycle, proved undeveloped reserves included in this table include only economic locations that are forecast to be on production before January 1, 2010. As of December 31, 2006, proved undeveloped reserves represent 62.7% of the Company's domestic total proved reserves.

	December 31, 2006	December 31, 2005 (In thousands)	December 31, 2004
Proved Undeveloped Reserves			
Natural gas (MMcf)	1,415,132	1,264,632	899,315
Oil (MBbl)	11,321	10,117	7,195
Proved Developed Reserves			
Natural gas (MMcf)	842,969	635,591	514,686
Oil (MBbl)	6,522	5,087	4,195
Total Proved Reserves (MMcfe)	2,365,159	1,991,447	1,482,341
Estimated future net cash flows, before income tax	$ 6,590,206	$ 12,067,267	$ 5,889,630
Standardized measure of discounted future net cash flows, before income taxes(1)	$ 2,690,464	$ 5,311,312	$ 2,438,837
Future income tax	$ 905,384	$ 1,809,228	$ 823,372
Standardized measure of discounted future net cash flows, after income tax	$ 1,785,080	$ 3,502,084	$ 1,615,465
Calculated weighted average price at December 31,			
Gas ($/Mcf) — WY	$ 4.50	$ 8.00	$ 5.46
Gas ($/Mcf) — PA	$ 5.51	—	—
Oil ($/Bbl)	$ 59.95	$ 60.81	$ 42.80

(1) Management believes that the presentation of the standardized measure of discounted future net cash flows, before income taxes, of estimated proved reserves, discounted at 10% per annum, may be considered a non-GAAP financial measure as defined in Item 10(e) of Regulation S-K, therefore the Company has included this reconciliation of the measure to the most directly comparable GAAP financial measure (Standardized measure of discounted future net cash flows, after income taxes). Management believes that the presentation of the standardized measure of future net cash flows before income taxes, provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and gas companies. Because many factors that are unique to each individual company may impact the amount of future income taxes to be paid, the use of the pre-tax measure provides greater comparability when evaluating companies. It is relevant and useful to investors for evaluating the relative monetary significance of the Company's oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of the Company's reserves to other companies. The standardized measure of discounted future net cash flows, before income taxes, is not a measure of financial or operating performance under GAAP, nor is it intended to represent the current market value of the estimated oil and natural gas reserves owned by the Company. Standardized measure of discounted future net cash flows, before income taxes, should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP.

The following table sets forth the Company's quantities of proved reserves in China, for the years ended December 31, 2006, 2005 and 2004 as estimated by independent petroleum engineers Ryder Scott Company. In accordance with the Company's "new field" reserve booking policy, proved reserves were booked after production has commenced. The table summarizes the Company's proved reserves in China, the estimated future net revenues from these reserves and the standardized measure of discounted future net cash flows attributable thereto at December 31, 2006, 2005 and 2004. In accordance with Ultra's three-year planning and budgeting cycle, proved undeveloped reserves included in this table include only economic locations that are forecast to be on production before January 1, 2010. At December 31, 2006, proved undeveloped reserves represent 32.6% of the Company's total proved reserves in China.

	December 31,		
	2006	2005	2004
		(In thousands)	
Proved Undeveloped Reserves			
Natural gas (MMcf)	—	—	—
Oil (MBbl)	1,301	2,577	3,231
Proved Developed Reserves			
Natural gas (MMcf)	—	—	—
Oil (MBbl)	2,686	2,484	4,356
Total Proved Reserves (MMcfe)	23,922	30,366	45,526
Estimated future net cash flows, before income tax	$111,994	$166,931	$137,762
Standardized measure of discounted future net cash flows, before income taxes(1)	$ 91,984	$134,271	$103,518
Future Income Tax	$ 5,511	$ 59,861	$ 49,647
Standardized measure of discounted future net cash flows, after income tax	$ 86,473	$ 74,410	$ 53,871
Calculated weighted average price at December 31, Oil ($/Bbl)	$ 46.57	$ 48.74	$ 29.46

(1) Management believes that the presentation of the standardized measure of discounted future net cash flows, before income taxes, of estimated proved reserves, discounted at 10% per annum, may be considered a non-GAAP financial measure as defined in Item 10(e) of Regulation S-K, therefore the Company has included this reconciliation of the measure to the most directly comparable GAAP financial measure (Standardized measure of discounted future net cash flows, after income taxes). Management believes that the presentation of the standardized measure of future net cash flows, before income taxes, provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and gas companies. Because many factors that are unique to each individual company may impact the amount of future income taxes to be paid, the use of the pre-tax measure provides greater comparability when evaluating companies. It is relevant and useful to investors for evaluating the relative monetary significance of the Company's oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of the Company's reserves to other companies. The standardized measure of discounted future net cash flows, before income taxes, is not a measure of financial or operating performance under GAAP, nor is it intended to represent the current market value of the estimated oil and natural gas reserves owned by the Company. Standardized measure of discounted future net cash flows, before income taxes, should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP.

The following table sets forth the Company's quantities of total proved reserves both domestically and in China, for the years-ended December 31, 2006, 2005 and 2004 as estimated by independent petroleum engineers Netherland, Sewell & Associates, Inc. and Ryder Scott Company. The table summarizes the Company's total proved reserves, the estimated future net revenues from these reserves and the standardized measure of discounted future net cash flows attributable thereto at December 31, 2006, 2005 and 2004. In accordance with Ultra's three-year planning and budgeting cycle, proved undeveloped reserves included in this table include only economic locations that are forecast to be on production before January 1, 2010. At December 31, 2006, proved undeveloped reserves represent 62.4% of the Company's total proved reserves.

	December 31,		
	2006	2005 (In thousands)	2004
Proved Undeveloped Reserves			
Natural gas (MMcf)	1,415,132	1,264,632	899,315
Oil (MBbl)	12,622	12,694	10,426
Proved Developed Reserves			
Natural gas (MMcf)	842,969	635,591	514,686
Oil (MBbl)	9,208	7,571	8,551
Total Proved Reserves (MMcfe)	2,389,081	2,021,813	1,527,867
Estimated future net cash flows, before income tax	$ 6,702,200	$ 12,234,198	$ 6,027,392
Standardized measure of discounted future net cash flows, before income taxes(1)	$ 2,782,448	$ 5,445,583	$ 2,542,355
Future income tax	$ 910,895	$ 1,869,089	$ 873,019
Standardized measure of discounted future net cash flows, after income tax	$ 1,871,553	$ 3,576,494	$ 1,669,336

(1) Management believes that the presentation of the standardized measure of discounted future net cash flows, before income taxes, of estimated proved reserves, discounted at 10% per annum, may be considered a non-GAAP financial measure as defined in Item 10(e) of Regulation S-K, therefore the Company has included this reconciliation of the measure to the most directly comparable GAAP financial measure (Standardized measure of discounted future net cash flows, after income taxes). Management believes that the presentation of the standardized measure of future net cash flows, before income taxes, provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and gas companies. Because many factors that are unique to each individual company may impact the amount of future income taxes to be paid, the use of the pre-tax measure provides greater comparability when evaluating companies. It is relevant and useful to investors for evaluating the relative monetary significance of the Company's oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of the Company's reserves to other companies. The standardized measure of discounted future net cash flows, before income taxes, is not a measure of financial or operating performance under GAAP, nor is it intended to represent the current market value of the estimated oil and natural gas reserves owned by the Company. Standardized measure of discounted future net cash flows, before income taxes, should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP.

Production Volumes, Average Sales Prices and Average Production Costs

The following table sets forth certain information regarding the production volumes and average sales prices received for and average production costs associated with the Company's sale of oil and natural gas for the periods indicated.

	Year Ended December 31, 2006	2005	2004
Production			
Natural gas (Mcf)	78,395,453	61,722,349	43,667,384
Oil (Bbl) — US	594,128	464,330	349,673
Oil (Bbl) — China	1,603,360	1,556,280	624,560
Total (Mcfe)	91,580,381	73,846,009	49,512,782
Revenues			
Natural Gas sales	$ 470,324,244	$ 422,091,034	$ 224,207,694
Oil sales — US	38,335,280	26,639,931	14,659,219
Oil sales — China	84,008,059	67,762,036	20,179,534
Total Revenues	$ 592,667,583	$ 516,493,001	$ 259,046,447
Lease Operating Expenses			
Production costs — US(a)	$ 15,067,413	$ 9,047,390	$ 6,286,715
Production costs — China(a)	8,922,400	7,352,000	2,286,000
Severance/production taxes — US	57,899,339	52,689,060	28,151,661
Severance/production taxes — China	8,398,473	3,388,089	1,009,098
Gathering	19,721,269	17,125,147	13,135,809
Total Lease Operating Expenses	$ 110,008,894	$ 89,601,686	$ 50,869,283
Realized Prices			
Natural Gas ($/Mcf, including hedges)	$ 6.00	$ 6.84	$ 5.13
Natural Gas ($/Mcf, excluding financial hedges)(b)	$ 6.00	$ 6.99	$ 5.32
Oil ($/Bbl) — US	$ 64.52	$ 57.37	$ 41.92
Oil ($/Bbl) — China	$ 52.40	$ 43.57	$ 32.31
Operating Costs per Mcfe			
Production costs	$ 0.26	$ 0.22	$ 0.17
Severance/production taxes	$ 0.72	$ 0.76	$ 0.59
Gathering	$ 0.22	$ 0.23	$ 0.27
DD&A	$ 1.02	$ 0.79	$ 0.61
Interest	$ 0.04	$ 0.04	$ 0.08
Total Operating Costs per Mcfe	$ 2.26	$ 2.04	$ 1.72

(a) Production costs include lifting costs and remedial workover expenses.

(b) In addition to our financial hedges and to a larger extent, we sell a portion of our production pursuant to fixed price forward natural gas sales contracts. During 2004, 2005 and 2006, we sold 12.1 MMBtu (24%), 22.2 MMBtu (30%) and 20.4 MMBtu (22%) pursuant to these contracts, respectively. The average price we received for production sold pursuant to term fixed price contracts was $4.40, $5.95 and $5.86 per MMBtu in 2004, 2005 and 2006, respectively. The average spot price (as measured by the Inside FERC First of Month Index for Northwest Pipeline — Rocky Mountains) was $5.24, $6.96 and $5.66 per MMBtu in 2004, 2005 and 2006, respectively. If we had sold the production we sold under the fixed price contracts at spot market prices during these periods, we may have received more or less than these prices, because the amount of production we sell could have influenced the spot market prices in the areas in which we produce and because we are able to select among several market indices when selling our production.

Productive Wells

As of December 31, 2006, the Company's total gross and net wells were as follows:

Productive Wells*	Gross Wells	Net Wells
Domestic		
Natural Gas and Condensate	488.00	209.70
China		
China Oil	79.00	6.89
TOTAL	567.00	216.59

* Productive wells are producing wells plus shut-in wells the Company deems capable of production. A gross well is a well in which a working interest is owned. The number of net wells represents the sum of fractional working interests the Company owns in gross wells.

Oil and Gas Acreage

As of December 31, 2006, the Company had total gross and net developed and undeveloped oil and natural gas leasehold acres in the United States and China as set forth below. The Company's material undeveloped properties are not subject to a material acreage expiry. The developed acreage is stated on the basis of spacing units designated by state regulatory authorities. The acreage and other additional information concerning the Company's oil and natural gas operations are presented in the following tables.

United States Acreage:

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
Wyoming	15,067	6,404	132,850	73,162
Pennsylvania	320	320	232,691	124,271
Texas	80	14	—	—
All States	15,467	6,738	365,541	197,433

As of December 31, 2006, the Company had total gross and net developed and undeveloped oil and natural gas leasehold acres in the Bohai Bay, China as set forth below.

Bohai Bay Acreage:

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
Block 04/36	40,377	3,598	413,623	75,197
Block 05/36	15,221	1,119	218,079	50,376
Total Bohai Acreage	55,598	4,717	631,702	125,573

Drilling Activities

For each of the three fiscal years ended December 31, 2006, 2005 and 2004, the number of gross and net wells drilled by the Company was as follows:

Wyoming — Green River Basin

	2006		2005		2004	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	80.00	38.44	60.00	23.68	34.00	14.48
Dry	0.00	0.00	0.00	0.00	0.00	0.00
Total	80.00	38.44	60.00	23.68	34.00	14.48

At year end, there were 17 gross (6.66 net) additional development wells that were either drilling or had drilling operations suspended. This includes wells in both the Pinedale and Jonah fields.

	2006		2005		2004	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive	44.00	19.79	18.00	8.62	32.00	14.00
Dry	0.00	0.00	0.00	0.00	0.00	0.00
Total	44.00	19.79	18.00	8.62	32.00	14.00

At year end there were 29 gross (10.98 net) additional exploratory wells that were either drilling or had drilling operations suspended.

Pennsylvania

	2006		2005		2004	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive	0.00	0.00	1.00	1.00	0.00	0.00
Dry	0.00	0.00	0.00	0.00	0.00	0.00
Total	0.00	0.00	1.00	1.00	0.00	0.00

At year end there were 2 gross (1.125 net) additional exploratory wells that were either drilling or had drilling operations suspended.

Texas

	2006		2005		2004	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive	0.00	0.00	0.00	0.00	0.00	0.00
Dry	0.00	0.00	0.00	0.00	1.00	0.73
Total	0.00	0.00	0.00	0.00	1.00	0.73

China — Bohai Bay

	2006		2005		2004	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	26.00	2.16	17.00	1.52	36.00	3.21
Dry	0.00	0.00	0.00	0.00	0.00	0.00
Total	26.00	2.16	17.00	1.52	36.00	3.21
Exploratory Wells						
Productive and Successful Appraisal*	0.00	0.00	0.00	0.00	0.00	0.00
Dry	1.00	0.23	1.00	0.18	1.00	0.18
Total	1.00	0.23	1.00	0.18	1.00	0.18

* A successful appraisal well is a well that is drilled into a formation shown to be productive of oil or natural gas by an earlier well for the purpose of obtaining more information about the reservoir.

Item 3. ***Legal Proceedings.***

The Company is currently involved in various routine disputes and allegations incidental to its business operations. While it is not possible to determine the ultimate disposition of these matters, the Company believes that the resolution of all such pending or threatened litigation is not likely to have a material adverse effect on the Company's financial position or results of operations.

Item 4. ***Submission of Matters to a Vote of Security Holders.***

No matters were submitted to a vote of the Company's security holders during the fourth quarter of the fiscal year ended December 31, 2006.

PART II

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

The common shares of the Company have been listed and posted for trading on the American Stock Exchange ("AMEX") since January 17, 2001 under the symbol "UPL". The following table sets forth the high and low intra-day sales prices on the AMEX for 2006 and 2005 as reported by the exchange. The prices are adjusted for a 2 for 1 stock split effective May 10, 2005.

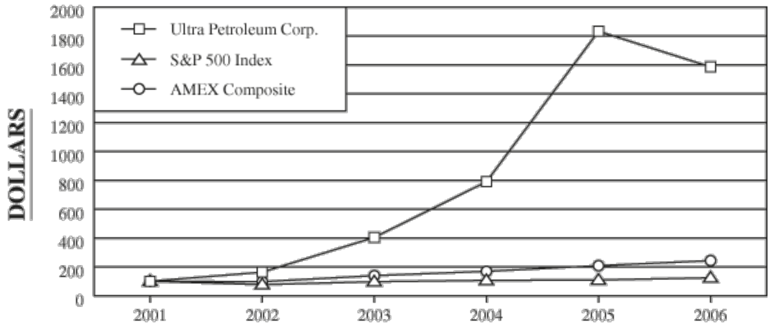
AMERICAN STOCK EXCHANGE (US$)

2006	High	Low
First Quarter	$70.00	$49.65
Second Quarter	$68.60	$44.40
Third Quarter	$61.84	$41.80
Fourth Quarter	$56.80	$44.60

AMERICAN STOCK EXCHANGE (US$)

2005	High	Low
First Quarter	$29.17	$22.20
Second Quarter	$30.50	$21.48
Third Quarter	$57.89	$30.36
Fourth Quarter	$60.32	$45.10

On February 15, 2007, the last reported sales price of the common stock on the AMEX was $51.55 per share. As of February 15, 2007 there were approximately 447 holders of record of the common stock.



The Company has not declared or paid and does not anticipate declaring or paying any dividends on its common stock in the near future. The Company intends to retain its cash flow from operations for the future operation and development of its business. In addition, the Company's current credit facility limits payment of dividends on its common stock.

On May 17, 2006, the Company announced that its Board of Directors authorized a share repurchase program for up to an aggregate $1 billion of the Company's outstanding common stock which has been and will be funded by cash on hand and the Company's senior credit facility. Pursuant to this authorization, the Company has commenced an initial program to purchase up to $250.0 million in shares of its common stock through open market transactions or privately negotiated transactions. At December 31, 2006, the Company had repurchased 3,969,532 shares of its common stock for an aggregate $197.6 million at a weighted average price of $49.77 per share.

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that may yet be Purchased Under the Plans or Programs
May 1 - May 31, 2006	283,417	$ 56.29	283,417	$ 984 million
June 1 - June 30, 2006	1,147,157	$ 50.03	1,147,157	$ 927 million
July 1 - July 31, 2006	572,858	$ 53.14	572,858	$ 896 million
Aug 1 - Aug 31, 2006	278,900	$ 53.02	278,900	$ 881 million
Sept 1 - Sept 30, 2006	1,198,700	$ 46.50	1,198,700	$ 826 million
Oct 1 - Oct 31, 2006	488,500	$ 47.56	488,500	$ 802 million
Nov 1 - Nov 30, 2006	—	—	—	$ 802 million
Dec 1 - Dec 31, 2006	—	—	—	$ 802 million
TOTAL	3,969,532	$ 49.77	3,969,532	$ 802 million

Item 6. ***Selected Financial Data.***

The selected consolidated financial information presented below for the years ended December 31, 2006, 2005, 2004, 2003, and 2002 is derived from the Consolidated Financial Statements of the Company. The earnings per share information (Basic income per common share and Diluted income per common share) have been updated to reflect the 2 for 1 stock split on May 10, 2005.

	Year Ended December 31,				
	2006	2005	2004	2003	2002
	(In thousands, except per share data)				
Statement of Operations Data					
Revenues:					
Natural gas sales	$ 470,324	$ 422,091	$ 224,208	$ 114,841	$ 38,503
Oil sales	122,343	94,402	34,839	6,740	3,839
Interest and other	1,943	612	91	37	23
Total revenues	$ 594,610	$ 517,105	$ 259,138	$ 121,618	$ 42,365
Expenses:					
Production expenses and taxes	110,009	89,602	50,869	25,224	11,411
Depreciation, depletion and amortization	93,499	58,103	30,249	16,216	9,712
General and administrative	13,378	11,484	6,152	5,733	4,199
Stock compensation	1,557	2,859	924	1,018	1,211
Interest	3,909	3,286	3,783	2,851	2,691
Total expenses	222,352	165,333	91,977	51,042	29,224
Income before income taxes	372,258	351,772	167,160	70,576	13,141
Income tax provision	141,063	123,472	58,010	25,254	5,059
Net income	$ 231,195	$ 228,300	$ 109,150	$ 45,323	$ 8,082
Basic income per common share	$ 1.50	$ 1.49	$ 0.73	$ 0.31	$ 0.05
Diluted income per common share	$ 1.43	$ 1.41	$ 0.68	$ 0.29	$ 0.05
Statement of Cash Flows Data					
Net cash provided by (used in):					
Operating activities	$ 435,857	$ 414,353	$ 175,343	$ 90,051	$ 21,490
Investing activities	(454,840)	(306,547)	(165,014)	(103,622)	(64,360)
Financing activities	(10,705)	(80,344)	4,770	13,988	42,908
Balance Sheet Data					
Cash and cash equivalents	$ 14,707	$ 44,395	$ 16,933	$ 1,834	$ 1,418
Working capital (deficit)	(41,429)	42,713	(9,969)	(22,057)	(4,415)
Oil and gas properties	1,119,368	702,663	474,634	307,864	207,362
Total assets	1,257,769	847,266	537,186	345,770	221,874
Total long-term debt	165,000	—	102,000	99,000	86,000
Other long-term obligations	26,573	20,577	9,735	5,120	3,859
Deferred income taxes, net	250,925	155,746	85,035	33,446	10,033
Total shareholders' equity	629,005	571,201	267,992	149,453	104,067

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

The following discussion of the financial condition and operating results of the Company should be read in conjunction with the consolidated financial statements and related notes of the Company. Except as otherwise indicated all amounts are expressed in U.S. dollars. We have one operating segment, natural gas and oil exploration and development with two geographical segments, the United States and China.

The Company currently generates the majority of its revenue, earnings and cash flow from the production and sales of natural gas and oil from its property in southwest Wyoming. The price of natural gas in the southwest Wyoming region is a critical factor to the Company's business. The price of natural gas in southwest Wyoming historically has been volatile. The average annual realizations for the period 2002-2006 have ranged from $2.33 to $8.64 per Mcf. This volatility could be detrimental to the Company's financial performance. The Company seeks to limit the impact of this volatility on its results by entering into forward sales and derivative contracts for natural gas in southwest Wyoming. The average realization for the Company's natural gas during calendar 2006 was $6.00 per Mcf, basis Opal, Wyoming, including the effect of hedges. For the quarter ended December 31, 2006, the average realization for the Company's natural gas was $5.62 per Mcf, basis Opal, Wyoming, including the effect of hedges.

On July 18, 2004 the Company initiated production at the first two fields of the nine fields discovered on its oil properties offshore Bohai Bay, China. Production from these fields is characterized as heavy, sweet crude. The Company sold its first cargo of oil in September 2004. During the twelve-month period ended December 31, 2006, the Company sold 1,603,360 barrels of its Chinese oil production at a price based on the official ICP posting for Duri field crude, less a discount for location and quality differences. The majority of these sales were made to an affiliate of CNOOC at an average price of $52.40 USD per barrel for the year ended December 31, 2006. For the quarter ended December 31, 2006, the Company sold 396,430 barrels of its Chinese crude for an average price of $39.53 USD per barrel. There can and will be differences in timing between the sale of the Company's crude oil cargos and the Company's pro-rata share of production. As a result of these timing differences, the Company may, from time to time, carry inventories or imbalances of crude oil. As of February 16, 2007, the Duri price was approximately $47.56 USD (before discount) per barrel.

The Company expects to sell at least one cargo of its Chinese crude oil production approximately every two months during 2007. The Company has the right to export and sell its crude at market prices into the international markets. Other markets for the Company's Chinese oil may potentially be developed in South Korea, Japan, Singapore or other countries.

The Company has grown its natural gas and oil production significantly over the past five years and management believes it has the ability to continue growing production by drilling already identified locations on its leases in Wyoming and by bringing into production the already discovered oil fields in China. The Company delivered 30% production growth on an Mcfe basis during the quarter ended December 31, 2006 as compared to the same quarter in 2005 and 24% production growth for the year-ended December 31, 2006 compared to the same period in 2005. Management expects to deliver additional production growth during 2007 by drilling and bringing into production additional wells in Wyoming and bringing into production additional fields in China.

	2006	2005	2004	2003
Production — Bcfe	91.6	73.8	49.5	28.9

The Company conducts operations in both the United States and China. Separate cost centers are maintained for each country in which the Company has operations. Substantially all of the oil and natural gas activities are conducted jointly with others and, accordingly, amounts presented reflect only the Company's proportionate interest in such activities. Inflation has not had a material impact on the Company's results of operations and is not expected to have a material impact on the Company's results of operations in the future.

Critical Accounting Policies

The discussion and analysis of the Company's financial condition and results of operations is based upon consolidated financial statements, which have been prepared in accordance with U.S. Generally Accepted Accounting Principles ("GAAP"). In addition, application of GAAP requires the use of estimates, judgments and assumptions that affect the reported amounts of assets and liabilities as of the date of the financial statements as well as the revenues and expenses reported during the period. Changes in these estimates, judgments and assumptions will occur as a result of future events, and, accordingly, actual results could differ from amounts estimated. Set forth below is a discussion of the critical accounting policies used in the preparation of our financial statements which we believe involve the most complex or subjective decisions or assessments. These policies relate to estimates of volumes of oil and natural gas reserves used in calculating depletion, the amount of standardized measure used in computing the ceiling test limitations and the amount of abandonment obligations used in such calculations. Assumptions, judgments and estimates are also required in determining impairments of undeveloped properties and the valuation of deferred tax assets.

Oil and Gas Reserves. The term proved reserves is defined by the SEC in Rule 4-10(a) of Regulation S-X under the Securities Act of 1933. In general, proved reserves are the estimated quantities of natural gas, crude oil, condensate and natural gas liquids that geological and engineering data demonstrate with reasonable certainty can be recovered in future years from known reservoirs under existing economic and operating conditions, i.e. prices and costs at the date of the estimate. Prices include consideration of changes in existing prices provided by contractual arrangements, but not escalated based on future economic conditions.

Estimates of proved crude oil and natural gas reserves significantly affect the Company's depreciation, depletion and amortization ("DD&A") expense. For example, if estimates of proved reserves decline, the Company's DD&A rate will increase, resulting in a decrease in net income. A decline in estimates of proved reserves may result from lower prices, evaluation of additional operating history, mechanical problems on our wells and catastrophic events such as explosions, hurricanes and floods. Lower prices also make it uneconomical to drill wells or produce from fields with high operating costs.

Our proved reserves are a function of many assumptions, all of which could deviate materially from actual results. As a result, our estimates of proved reserves could vary over time, and could vary from actual results.

Full Cost Method of Accounting. The accounting for and disclosure of oil and gas producing activities requires that we choose between GAAP alternatives. The Company uses the full cost method of accounting for its oil and natural gas operations. Under this method, separate cost centers are maintained for each country in which the Company incurs costs. All costs incurred in the acquisition, exploration and development of properties (including costs of surrendered and abandoned leaseholds, delay lease rentals, dry holes and overhead related to exploration and development activities) are capitalized. The sum of net capitalized costs and estimated future development costs of oil and natural gas properties for each full cost center are depleted using the units-of-production method. Changes in estimates of proved reserves, future development costs or asset retirement obligations are accounted for prospectively in our depletion calculation.

Investments in unproved properties are not depleted pending the determination of the existence of proved reserves. Unproved properties are assessed periodically to ascertain whether impairment has occurred. Unproved properties whose costs are individually significant are assessed individually by considering the primary lease terms of the properties, the holding period of the properties, and geographic and geologic data obtained relating to the properties. Where it is not practicable to individually assess the amount of impairment of properties for which costs are not individually significant, such properties are grouped for purposes of assessing impairment. The amount of impairment assessed is added to the costs to be amortized in the appropriate full cost pool.

Companies that use the full cost method of accounting for oil and natural gas exploration and development activities are required to perform a ceiling test calculation each quarter on a country-by-country basis. The ceiling limits such pooled costs to the aggregate of the after-tax, present value, discounted at 10%, of future net revenues attributable to proved reserves, known as the standardized measure, plus the lower of cost or market value of unproved properties less any associated tax effects. If such capitalized costs exceed the ceiling, the Company will record a write-down to the extent of such excess as a non-cash charge to earnings. Any such write-down will reduce earnings in the period of occurrence and result in lower DD&A expense in future periods. A write-down may not be reversed in future periods, even though higher oil and natural gas prices may subsequently increase the ceiling.

The Company did not have any write-downs related to the full cost ceiling limitation in 2006, 2005, or 2004. As of December 31, 2006, the ceiling limitation exceeded the carrying value of the Company's oil and natural gas properties. Estimates of standardized measure at December 31, 2006 were based on realized natural gas prices which averaged $4.50 per Mcf in Wyoming and $5.51 per Mcf in Pennsylvania and on realized liquids prices which averaged $59.95 per barrel in the U.S. In China, estimates of discounted future net cash flows on crude oil were based on a net realized price of $46.57 per barrel. A reduction in oil and natural gas prices and/or estimated quantities of oil and natural gas reserves would reduce the ceiling limitation and could result in a ceiling test write-down.

Asset Retirement Obligation. The Company's asset retirement obligations ("ARO") consist primarily of estimated costs of dismantlement, removal, site reclamation and similar activities associated with its oil and natural gas properties. Statement of Financial Accounting Standard No. 143, "Accounting for Asset Retirement Obligations" ("SFAS No. 143") requires that the discounted fair value of a liability for an ARO be recognized in the period in which it is incurred with the associated asset retirement cost capitalized as part of the carrying cost of the oil and natural gas asset. The recognition of an ARO requires that management make numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an ARO, estimated probabilities, amounts and timing of settlements; the credit-adjusted, risk-free rate to be used; inflation rates, and future advances in technology. In periods subsequent to initial measurement of the ARO, the Company must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to passage of time impact net income as accretion expense. The related capitalized cost, including revisions thereto, is charged to expense through DD&A.

Entitlements Method of Accounting for Oil and Natural Gas Sales. The Company generally sells natural gas, condensate and crude oil under both long-term and short-term agreements at prevailing market prices and under multi-year contracts that provide for a fixed price of oil and natural gas. The Company recognizes revenues when the oil and natural gas is delivered, which occurs when the customer has taken title and has assumed the risks and rewards of ownership, prices are fixed or determinable and collectibility is reasonably assured. The Company accounts for oil and natural gas sales using the "entitlements method." Under the entitlements method, revenue is recorded based upon the Company's ownership share of volumes sold, regardless of whether it has taken its ownership share of such volumes. The Company records a receivable or a liability to the extent it receives less or more than its share of the volumes and related revenue.

Make-up provisions and ultimate settlements of volume imbalances are generally governed by agreements between the Company and its partners with respect to specific properties or, in the absence of such agreements, through negotiation. The value of volumes over- or under-produced can change based on changes in commodity prices. The Company prefers the entitlements method of accounting for oil and natural gas sales because it allows for recognition of revenue based on its actual share of jointly owned production, results in better matching of revenue with related operating expenses, and provides balance sheet recognition of the estimated value of product imbalances.

Valuation of Deferred Tax Assets. The Company uses the asset and liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are determined based on differences between the financial statement carrying values and their respective income tax basis (temporary differences).

To assess the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. As of December 31, 2006, the Company had net deferred tax assets totaling $8.3 million which management considers is more likely than not to be realized.

Commodity Derivative Instruments and Hedging Activities. The Company may, from time to time, enter into commodity derivative contracts and/or fixed-price physical contracts to manage its exposure to oil and natural gas price volatility. The Company has, in the past, primarily utilized fixed price forward sales of physical gas when it hedges some portion of its Wyoming natural gas production. These transactions are generally placed with major financial institutions or with counterparties of high credit quality that present minimal credit risks to the Company. The Company may also secure payments under these types of transactions by requiring the counterparty to provide letter(s) of credit. On a less frequent basis, the Company may enter into commodity derivative contracts to manage price volatility. To the extent that it does enter into such derivative transactions, the Company expects that the oil and natural gas reference prices of these commodity derivatives contracts will be based upon crude oil and/or natural gas futures contracts which, when adjusted for location basis differentials, will have a high degree of historical correlation with actual prices the Company receives. Under Statement of Financial Accounting Standard No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS No. 133"), all derivative instruments are recorded on the balance sheet at fair value. Changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. For qualifying cash flow hedges, the gain or loss on the derivative is deferred in Accumulated Other Comprehensive Income (Loss) to the extent the hedge is effective. For qualifying fair value hedges, the gain or loss on the derivative is offset by the related results of the hedged item in the income statement. Gains and losses on hedging instruments included in Accumulated Other Comprehensive Income (Loss) on the balance sheet are reclassified to Oil and Natural Gas Sales Revenue in the period that the related production is delivered. Derivative contracts that do not qualify for hedge accounting treatment are recorded as derivative assets and liabilities at market value in the consolidated balance sheet, and the associated unrealized gains and losses are recorded as current expense or income in the consolidated statement of operations. The Company currently does not have any derivative contracts related to the marketing of its natural gas or oil production in effect, the last one having expired on December 31, 2005.

Legal, Environmental and Other Contingencies. A provision for legal, environmental and other contingencies is charged to expense when the loss is probable and the cost can be reasonably estimated. Determining when expenses should be recorded for these contingencies and the appropriate amounts for accrual is a complex estimation process that includes the subjective judgment of management. In many cases, management's judgment is based on interpretation of laws and regulations, which can be interpreted differently by regulators and/or courts of law. The Company's management closely monitors known and potential legal, environmental and other contingencies and periodically determines when the Company should record losses for these items based on information available to the Company.

Share-Based Payment Arrangements. On January 1, 2006, the Company adopted Statement of Financial Accounting Standards No. 123 (revised 2004), "Share-Based Payment" ("SFAS No. 123R") which requires the measurement and recognition of compensation expense for all share-based payment awards made to employees and directors including employee stock options based on estimated fair values. SFAS No. 123R supersedes the Company's previous accounting under Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" ("APB No. 25") for periods beginning in fiscal year 2006. In March 2005, the SEC issued Staff Accounting Bulletin No. 107 ("SAB 107") relating to SFAS No. 123R. The Company has applied the provisions of SAB 107 in its adoption of SFAS No. 123R.

The Company adopted SFAS No. 123R using the modified prospective transition method, which requires the application of the accounting standard as of January 1, 2006, the first day of the Company's fiscal year 2006. The Company's Consolidated Financial Statements as of and for the year-ended December 31, 2006 reflect the impact of SFAS No. 123R. In accordance with the modified prospective transition method, the Company's Consolidated Financial Statements for prior periods have not been restated to reflect, and do not include, the impact of SFAS No. 123R. Share-based compensation expense recognized under SFAS No. 123R for the year-ended December 31, 2006 was $1,156,767, which consisted of stock-based compensation expense related to employee stock options. There was no stock-based compensation expense related to employee stock options recognized during the year-ended December 31, 2005. (See Note 1(l) for additional information.)

SFAS No. 123R requires companies to estimate the fair value of share-based payment awards on the date of grant using an option-pricing model. The value of the portion of the award that is ultimately expected to vest is recognized as expense over the requisite service periods in the Company's Consolidated Statement of Operations. Prior to the adoption of SFAS No. 123R, the Company accounted for stock-based awards to employees and directors using the intrinsic value method in accordance with APB No. 25 as allowed under Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation" ("SFAS No. 123"). Under the intrinsic value method, no stock-based compensation expense had been recognized in the Company's Consolidated Statement of Operations because the exercise price of the Company's stock options granted to employees and directors equaled the fair market value of the underlying stock at the date of grant.

Under SFAS No. 123R, share-based compensation expense recognized during the period is based on the value of the portion of share-based payment awards that is ultimately expected to vest during the period. Share-based compensation expense recognized in the Company's Consolidated Statement of Operations for the year-ended

December 31, 2006 includes compensation expense for share-based payment awards granted subsequent to January 1, 2006 based on the grant date fair value estimated in accordance with the provisions of SFAS No. 123R. As of December 31, 2005, all stock options granted to date had fully vested. Compensation expense attributable to awards granted subsequent to January 1, 2006 is recognized using the straight-line method. As share-based compensation expense recognized in the Consolidated Statements of Operations for the year-ended December 31, 2006 is based on awards ultimately expected to vest, it has been reduced for estimated forfeitures. SFAS No. 123R requires forfeitures to be estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates. In the Company's pro forma information required under SFAS No. 123 for the periods prior to January 1, 2006, the Company accounted for forfeitures as they occurred.

Under SFAS No. 123 (and APB No. 25), the Company utilized a Black-Scholes option pricing model to measure the fair value of stock options granted to employees. For additional information, see Note 6. The Company's determination of fair value of share-based payment awards on the date of grant using an option-pricing model is affected by the Company's stock price as well as assumptions regarding a number of highly complex and subjective variables. These variables include, but are not limited to, the Company's expected stock price volatility over the term of the awards, and actual and projected employee stock option exercise behaviors.

Option-pricing models were developed for use in estimating the value of traded options that have no vesting or hedging restrictions and are fully transferable. Because (1) the Company's employee stock options have certain characteristics that are significantly different from traded options, and (2) changes in the subjective assumptions can materially affect the estimated value, in management's opinion, the existing valuation models may not provide an accurate measure of the fair value of the Company's employee stock options. Although the fair value of employee stock options is determined in accordance with SFAS No. 123R and SAB 107 using a Black-Scholes option-pricing model, that value may not be indicative of the fair value observed in a willing buyer/willing seller market transaction. The Company is responsible for determining the assumptions used in estimating the fair value of its share-based payment awards.

Recently issued accounting pronouncements. As of January 1, 2006, the Company adopted SFAS No. 154, "Accounting for Changes and Error Corrections, a replacement of APB Opinion No. 20 and SFAS No. 3" ("SFAS No. 154"). SFAS No. 154 requires retrospective application of voluntary changes in accounting principles, unless it is impracticable. The adoption of this standard did not have a material impact on consolidated results of operations, financial position or liquidity.

In July 2006, the Financial Accounting Standards Board ("FASB") issued Interpretation No. 48 ("FIN No. 48"), "Accounting for Uncertainty in Income Taxes, an Interpretation of SFAS No. 109," which clarifies the accounting for uncertainty in income taxes in accordance with SFAS No. 109, "Accounting for Income Taxes." FIN No. 48 prescribes a recognition threshold and measurement attribute for the measurement and financial statement recognition of a tax position taken or expected to be taken in a tax return. The interpretation also provides guidance on de-recognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. Upon adoption, FIN No. 48 will be applied to all tax positions in those tax years for which the tax return statute of limitations is open. The cumulative effect of the initial application will be reported as an increase or decrease to retained earnings as of the beginning of the period in which it is adopted. For the Company, the provisions of FIN No. 48 are effective January 1, 2007. The Company has not completed its evaluation of the impact FIN No. 48 will have when adopted. However, the Company currently believes that its implementation will not have a material impact on consolidated results of operations, financial position or liquidity.

In September 2006, the SEC staff issued Staff Accounting Bulletin 108, "Financial Statements — Considering the Effects of Prior Year Misstatements When Quantifying Misstatements in Current Year Financial Statements" ("SAB 108"). SAB 108 addresses how a registrant should quantify the effect of an error on the financial statements and concludes that a dual approach should be used to compute the amount of a misstatement. Specifically, the amount should be computed using both the "rollover" (current year income statement perspective) and "iron curtain" (year-end balance sheet perspective) methods. For the Company, the provisions of SAB 108 were effective January 1, 2006. The implementation of SAB 108 did not have a material impact on the Company's consolidated results of operations, financial position or liquidity.

Results of Operations — Year Ended December 31, 2006 Compared to Year Ended December 31, 2005

Oil and natural gas revenues increased 15% to $592.7 million for the year ended December 31, 2006 from $516.5 million for the same period in 2005. This increase was attributable to an increase in the Company's production volumes and partially offset by lower prices received. During 2006, the Company's production increased to 78.4 Bcf of natural gas and 594.1 thousand barrels of condensate in Wyoming and 1.6 million barrels of crude oil in China, up from 2005 levels of 61.7 Bcf of natural gas and 464.3 thousand barrels of condensate in Wyoming and 1.6 million barrels of crude oil in China. This 24% increase on an Mcfe basis was attributable to the Company's successful drilling activities during 2006 and 2005 in Wyoming and in China. During the year ended December 31, 2006, the average product prices received were $6.00 per Mcf including the effects of hedging and $64.52 per barrel of condensate in Wyoming and $52.40 per barrel for crude oil in China, compared to $6.84 per Mcf and $57.37 per barrel of condensate in Wyoming and $43.57 per barrel of crude oil in China for the same period in 2005.

In Wyoming, direct lease operating costs increased to $15.1 million in 2006 from $9.0 million in 2005 due to higher production volumes along with increased water disposal costs. On a unit of production basis, LOE costs increased to $0.18 per Mcfe for the year-ended December 31, 2006 as compared to $0.14 per Mcfe during the same period in 2005. Production taxes in Wyoming during the year-ended December 31, 2006 were $57.9 million compared to $52.7 million in 2005, or $0.71 per Mcfe in 2006, compared to $0.82 per Mcfe in 2005. Production taxes in Wyoming are calculated based on a percentage of revenue from production. Therefore, lower prices received decreased production taxes on a per unit basis. Gathering fees in Wyoming for the year ended December 31, 2006 increased to $19.7 million in 2006 from $17.1 million in 2005 largely as a result of increased production volumes partially offset by revised gathering and processing agreements. The per unit gathering fees decreased to $0.24 per Mcfe in 2006 as compared to $0.27 per Mcfe in 2005 as a result of increased production volumes during 2006 as well as reduced fees as a result of revised gathering and processing agreements during 2006.

In the United States, DD&A expenses increased to $79.7 million during the year ended December 31, 2006 from $48.5 million for the same period in 2005. This increase was attributable to increased production volumes and a higher depletion rate due to forecasted increased future development costs. On a unit basis, DD&A expense in the United States increased to $0.97 per Mcfe in 2006 from $0.75 per Mcfe in 2005.

In China, production costs were $8.9 million in 2006, or $0.93 per Mcfe or $5.58 per BOE, compared with $7.4 million in 2005, or $0.79 per Mcfe or $4.74 per BOE. The increase in production costs was attributable to increased production during 2006 along with one-time costs associated with new fields coming on production. Severance taxes in China during the year ended December 31, 2006 were $8.4 million compared to $3.4 million in 2005, or $0.87 per Mcfe ($5.22 per BOE) in 2006 compared to $0.36 per Mcfe ($2.18 per BOE) in 2005. The increase in severance taxes was largely attributable to $3.6 million related to the Petroleum Special Profits Tax levied by the Chinese government beginning in March 2006. In addition, in November 2006, the Chinese government introduced an export levy on produced volumes exported out of the country. The Company incurred $0.5 million during the year ended December 31, 2006 relating to the export levy.

In China, DD&A expense was $13.8 million or $1.44 per Mcfe ($8.64 per BOE) in 2006 compared to $9.6 million, or $1.03 per Mcfe ($6.20 per BOE) in 2005. The increase in DD&A was primarily attributable to higher DD&A rates as a result of costs being allocated from unevaluated properties to the full cost pool as well as increased production volumes.

General and administrative expenses increased slightly to $14.9 million during the twelve months ended December 31, 2006 as compared to $14.3 million during the same period in 2005. On a per unit basis, general and administrative expenses decreased to $0.16 per Mcfe during the year-ended December 31, 2006 as compared to $0.19 per Mcfe for the same period in 2005.

Interest expense increased to $3.9 million in 2006 from $3.3 million in 2005. This increase was largely attributable to the increase in borrowings under the senior credit facility during 2006.

The income tax provision increased to $141.1 million in 2006 from $123.5 million in 2005. This increase was primarily attributable to increased earnings as well as the withholding tax paid in association with our share repurchase program (see Note 8). The Company recognized $35.4 million in current tax expense during 2006, of which, $18.9 million was payable to the Chinese taxing authorities. The Company incurred a liability for current payment of income taxes of $3.6 million for the period ending December 31, 2005. During the year-ended December 31, 2006, the Company incurred $10.4 million in withholding tax attributable to the Company's share repurchase program. In conjunction with the share repurchase program, a stock distribution to Ultra Petroleum from Ultra Resources is treated as a dividend for U.S. tax purposes to the extent of earnings and profits of UP Energy and Ultra Resources. U.S. tax rules, including rules under the U.S.-Canada Income Tax Treaty, require a 5% withholding tax when a U.S. corporation distributes a dividend to its sole corporate Canadian shareholder.

The following table provides a detail of the income tax provision for the years ended December 31, 2006 and 2005.

	For the Year-Ended December 31,			
	2006		2005	
	$	Rate	$	Rate
Current:				
China	$ 18,941,127	5.1%	$ 3,564,990	1.0%
United States	16,543,461	4.4%	$ 50,636,118	14.4%
Withholding taxes — stock distribution	10,400,543	2.8%	—	0.0%
Deferred tax expense	95,178,288	25.6%	69,270,977	19.7%
Total Income Tax Provision	$ 141,063,419	37.9%	$ 123,472,085	35.1%
Deferred taxes payable	$ (95,178,288)	(25.6)%	$ (69,270,977)	(19.7)%
Stock option benefits	(10,502,522)	(2.8)%	(50,636,118)	(14.4)%
Current net cash tax liability	$ 35,382,609	9.5%	$ 3,564,990	1.0%

Results of Operations — Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

Oil and natural gas revenues increased to $516.5 million for the year ended December 31, 2005 from $259.0 million for the same period in 2004. This increase was attributable to an increase in both the Company's production volumes and prices received for that production coupled with a full year's production from the China asset. During 2005, the Company's production increased to 61.7 Bcf of natural gas and 464.3 thousand barrels of condensate in Wyoming and 1.6 million barrels of crude oil in China, up from 2004 levels of 43.7 Bcf of natural gas and 349.7 thousand barrels of condensate in Wyoming and 624.6 thousand barrels of crude oil in China. This 49% increase on an Mcfe basis was attributable to the Company's successful drilling activities during 2005 and 2004 in Wyoming and initiation of production in China during July 2004. During the year ended December 31, 2005, the average product prices received were $6.84 per Mcf and $57.37 per barrel of condensate in Wyoming and $43.54 per barrel for crude oil in China, compared to $5.13 per Mcf and $41.92 per barrel of condensate in Wyoming and $32.31 per barrel of crude oil in China for the same period in 2004.

In Wyoming, direct lease operating costs increased to $9.0 million in 2005 from $6.3 million in 2004 due largely to higher production volumes. On a unit of production basis, LOE costs were flat at $0.14 per Mcfe in 2005 when compared to 2004. Production taxes in Wyoming during the year ended December 31, 2005 were $52.7 million compared to $28.2 million in 2004, or $0.82 per Mcfe in 2005, compared to $0.62 per Mcfe in 2004. Production taxes in Wyoming are calculated based on a percentage of revenue from production. Therefore, higher prices received increased production taxes on a per unit basis. Gathering fees in Wyoming for the year ended December 31, 2005 increased to $17.1 million, or $0.27 per Mcfe in 2005 from $13.1 million, or $0.29 per Mcfe, in 2004 as a result of higher production volumes.

In Wyoming, DD&A expenses increased to $48.5 million during the year ended December 31, 2005 from $27.3 million for the same period in 2004, attributable to increased production volumes and a higher depletion rate due to forecasted increased future development costs. On a unit basis, DD&A expense in Wyoming increased to $0.75 per Mcfe in 2005 from $0.60 per Mcfe in 2004.

In China, production costs were $7.4 million in 2005, or $0.79 per Mcfe or $4.72 per BOE, compared with $2.3 million in 2004, or $0.61 per Mcfe or $3.66 per BOE. Severance taxes in China during the year ended December 31, 2005 were $3.4 million compared to $1.0 million in 2004, or $0.36 per Mcfe ($2.18 per BOE) in 2005 compared to $0.27 per Mcfe ($1.62 per BOE) in 2004. The increase in severance taxes relates to a full year of production during 2005 compared to half year in 2004. In China, DD&A expense was $9.6 million or $1.03 per Mcfe or $6.20 per BOE, in 2005 compared to $2.9 million, or $0.77 per Mcfe or $4.65 per BOE in 2004. Production commenced in China during July 2004.

Interest expense decreased to $3.3 million in 2005 from $3.8 million in 2004. This decrease was largely attributable to the decrease in borrowings under the senior credit facility and was partially offset by increased interest rates during 2005.

Income tax expense increased to $123.5 million in 2005 from $58.0 million in 2004. This increase was primarily attributable to an increase in net income from continuing operations combined with an increase in the tax rate. Income taxes were booked at the rate of 35.1% for the year ended December 31, 2005 as compared to a rate of 34.7% in 2004. The Company was not liable for current payment of any material amount of income taxes for the period ending December 31, 2005.

Liquidity and Capital Resources

During the year-ended December 31, 2006, the Company relied on cash provided by operations and borrowings under its senior credit facility to finance its capital expenditures. The Company participated in the drilling of 170 wells in Wyoming and continued to participate in the development process in the China Blocks, including the ongoing drilling of development wells. For the year-ended December 31, 2006 net capital expenditures were $503.9 million. At December 31, 2006, the Company reported a cash position of $14.7 million compared to $44.4 million at December 31, 2005. Working capital at December 31, 2006 was ($41.4) million as compared to $42.7 million at December 31, 2005. As of December 31, 2006, the Company had $165.0 million in outstanding bank indebtedness and other long-term obligations of $26.6 million comprised of items payable in more than one year, primarily related to production taxes.

The Company's cash provided by operating activities, along with availability under its senior credit facility, are projected to be sufficient to fund the Company's budgeted capital expenditures for 2007, which are currently projected to be $600.0 million. Of the $600.0 million budget, the Company plans to allocate approximately 93% to Wyoming, 4% to Pennsylvania and 3% to China. With the budget allocated for Wyoming, the Company plans to drill or participate in an estimated 185 gross wells in 2007, of which approximately 25% will be for exploration wells and the remaining will be for development wells. Of the allocation for China, approximately 33% will be for exploratory/appraisal activity and the balance will be for development activity. The Company currently has no budget for acquisitions in 2007.

The Company (through its subsidiary) participates in a revolving credit facility with a group of banks led by JP Morgan Chase Bank, N.A. The agreement specifies a maximum loan amount of $500 million, an aggregate borrowing base of $1.1 billion and a commitment amount of $200 million at December 31, 2006. The commitment amount may be increased up to the lesser of the borrowing base amount or $500 million at any time at the request of the Company. Each bank shall have the right, but not the obligation, to increase the amount of their commitment as requested by the Company. In the event that the existing banks increase their commitment to an amount less than the requested commitment amount, then it would be necessary to bring additional banks into the facility. At December 31, 2006, the Company had $165.0 million outstanding and $35.0 million unused and available under the current committed amount.

The credit facility matures on May 1, 2010. The note bears interest at either (A) the bank's prime rate plus a variable margin ranging from zero percent (0.00%) to three-quarters of one percent (0.75%) based on the percentage of available credit drawn or at (B) LIBOR plus a variable margin ranging from one percent (1.00%) to one and three-quarters of one percent (1.75%) based on the percentage of available credit drawn. For purposes of calculating interest, the available credit is equal to the borrowing base. An average annual commitment fee of 0.25% to 0.375%, depending on the percentage of available credit drawn, is charged quarterly for any unused portion of the commitment amount. The Company's total commitment fees were $377,173, $354,017 and $374,096 for the years ended December 31, 2006, 2005 and 2004, respectively.

The borrowing base is subject to periodic (at least semi-annual) review and re-determination by the banks and may be decreased or increased depending on a number of factors, including the Company's proved reserves and the bank's forecast of future oil and natural gas prices. If the borrowing base is reduced to an amount less than the balance outstanding, the Company has sixty days from the date of written notice of the reduction in the borrowing base to pay the difference. Additionally, the Company is subject to quarterly reviews of compliance with the covenants under the bank facility including minimum coverage ratios relating to interest, working capital and advances to Sino-American Energy Corporation. In the event of a default under the covenants, the Company may not be able to access funds otherwise available under the facility. As of December 31, 2006, the Company was in compliance with required covenants of the bank facility.

Any debt outstanding under the credit facility is secured by a majority of the Company's proved domestic oil and natural gas properties.

During the year-ended December 31, 2006, net cash provided by operating activities was $435.9 million, a 5% increase over the $414.4 million for the same period in 2005. The increase in net cash provided by operating activities was largely attributable to the increase in production during the year-ended December 31, 2006.

During the year-ended December 31, 2006, net cash used in investing activities was $454.8 million as compared to $306.5 million for the same period in 2005. The increase in net cash used in investing activities is largely due to increased capital expenditures associated with the Company's drilling activities.

During the year-ended December 31, 2006, net cash used in financing activities was $10.7 million as compared to $80.3 million for the same period in 2005. The change in net financing activities is primarily attributable to borrowings under the Company's senior credit facility during 2006 offset by the repurchase of shares under the Company's share repurchase program during the year-ended December 31, 2006 (See Note 8).

Off-Balance Sheet Arrangements

The company did not have any off-balance sheet arrangements as of December 31, 2006.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2006:

	Payments Due by Period:				
	Total	Less Than One Year	1-3 Years	3-5 Years	More Than 5 Years
Long-term debt	$ 165,000,000	$ —	$ —	$ 165,000,000	$ —
Drilling contracts	136,990,625	74,848,535	62,142,090	—	—
Operating leases	799,026	799,026	—	—	—
Office space lease	636,157	408,347	227,810	—	—
Total contractual obligations	$ 303,425,808	$ 76,055,908	$ 62,369,900	$ 165,000,000	$ —

As of December 31, 2006, the Company had committed to drilling obligations with certain rig contractors that will continue into 2009. The mentioned drilling rigs were contracted to fulfill the 2006-2009 drilling program initiatives in Wyoming.

On October 16, 2003 the operator of the Company's properties in China, Kerr-McGee (now Anadarko Petroleum), signed a 15 year contract, which provides for up to an additional 10 years, to lease the FPSO. The Company ratified the contract for its net share which is 8.91%. The FPSO service agreement calls for a day rate lease payment and a sliding scale per barrel processing fee that decreases based on cumulative barrels processed. The lease contains a cancellation fee for the Company based on a sliding time-scale (cancellation fee decreases with time) which as of December 31, 2006 was $2.7 million, net to the Company's interest. The Company considers it very unlikely that a lease cancellation situation will occur. Due to the terms of the lease, the Company cannot estimate with any degree of accuracy the costs it may incur during the life of the lease. The Company's net share for the costs of the FPSO in 2006 was approximately $3.2 million.

In May 2003, the Company amended its prior office lease in Englewood, Colorado, which it has committed to through June 2008. The Company's total remaining commitment for this lease is $504,769 at December 31, 2006 ($333,359 in 2007 and $171,410 in 2008). In December 2003, the Company signed a lease for office space in Houston, Texas, which it has committed to through April 2007 for a total remaining commitment at December 31, 2006 of $33,948. At December 31, 2006, the remaining commitment on the Company's Pinedale office is $97,440 ($41,040 in 2007, $33,840 in 2008 and $22,560 in 2009). The total remaining commitment for all offices is $636,157.

On December 19, 2005, the Company signed two Precedent Agreements ("Precedent Agreements") with Rockies Express Pipeline, LLC ("REX") and Entrega Gas Pipeline, LLC governing how the parties will proceed through the design, regulatory process and construction of the pipeline facilities and, subject to certain conditions precedent, the Company will take firm transportation service if and when the pipeline facilities are constructed. Commencing upon completion of the pipeline facilities, the Company's commitment involves capacity of 200,000 MMBtu per day of natural gas for a term of 10 years, and the Company will be obligated to pay to REX certain demand charges related to its rights to hold this firm transportation capacity as an anchor shipper. Based on current assumptions, current projections regarding the cost of the expansion and the participation of other shippers in the expansion (noting specifically that these assumptions are likely to change materially), the Company currently projects that annual demand charges due may be approximately $70.0 million per year for the term of the contract, exclusive of fuel and surcharges. The Company's Board of Directors approved the Precedent Agreements on February 6, 2006 and Kinder Morgan, as the managing member of REX advised the Company of their final approval of the Precedent Agreements, and their intent to proceed with the construction of the Rockies Express Pipeline on February 28, 2006.

The pipeline facilities are currently anticipated to be completed in stages between 2008 and 2009. REX filed its application for a Certificate of Public Convenience and Necessity for the Rockies Express West Project ("REX-West") with the FERC on May 31, 2006. The REX-West portion of the project is 713 miles of pipeline commencing at Cheyenne Hub (Weld County, CO) and terminating in Audrain County, Missouri. FERC issued a Preliminary Determination on Non-Environmental Issues related to the REX-West application on September 21, 2006, stating that, subject to certain conditions, the REX's proposals are in the public interest. This order did not consider or evaluate any environmental issues, which will be addressed in a subsequent FERC order, which is expected during 2007. FERC also issued a Draft Environmental Impact Statement on REX-West, on November 3, 2006. REX has indicated to the Company that, upon receipt of the final FERC order on environmental issues, construction of the REX-West portion of the project will commence. This is expected to occur early in the second quarter of 2007. The REX partners have indicated that they will file the application for a Certificate of Public Convenience and Necessity for the Rockies Express East segment (Missouri to Ohio) of the proposed project following receipt of the order approving the REX-West Certificate of Public Convenience and Necessity.

Additionally, in maintaining its acreage base that is not held by production, the Company incurs certain expenses, including delay rental costs. From year to year, the Company's acreage base varies, sometimes dramatically, rendering it impossible to forecast with any accuracy what the amount of these delay rental costs will be. In 2006, delay rental costs for all of the Company's leases not held by production were $319,977.

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk.***

The Company's major market risk exposure is in the pricing applicable to its natural gas and oil production. Realized pricing is currently driven primarily by the prevailing price for the Company's Wyoming natural gas production. Historically, prices received for natural gas production have been volatile and unpredictable. Pricing volatility is expected to continue. Natural gas price realizations ranged from a monthly low of $4.50 per Mcf to a monthly high of $8.26 per Mcf during 2006. Realized natural gas prices are derived from the financial statements which include the effects of hedging and natural gas balancing.

The Company primarily relies on fixed price forward natural gas sales to manage its commodity price exposure. See Management's Discussion and Analysis of Financial Condition and Results of Operations — Commodity Derivative Instruments and Hedging.

The Company had the following fixed price physical delivery contracts in place on behalf of its interest and those of other parties at December 31, 2006. (The Company's approximate average net interest in physical gas sales is 80%.)

Contract Period	Volume MMbtu/Day	Average Price/MMbtu
April 2007 - October 2007	40,000	$ 6.20

Subsequent to December 31, 2006 and through February 26, 2007, the Company has entered into the following fixed price physical delivery contracts on behalf of its interest and those of other parties:

Contract Period	Volume MMbtu/Day	Average Price/MMbtu
Calendar 2008	60,000	$ 6.63

Item 8. ***Financial Statements and Supplementary Data.***

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of the Company is responsible for the preparation and integrity of all information contained in this Annual Report. The accompanying financial statements have been prepared in conformity with accounting principles generally accepted in the United States of America. The financial statements include amounts that are management's best estimates and judgments.

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Under the supervision and with the participation of our management, including our chief executive officer and chief financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in Internal Control — Integrated Framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2006.

Management's assessment of the effectiveness of the Company's internal controls over financial reporting as of December 31, 2006 has been fully audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report which is included herein.

/s/ Michael D. Watford
Michael D. Watford
Chief Executive Officer

February 26, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of Ultra Petroleum Corp.

We have audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that Ultra Petroleum Corp. maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Ultra Petroleum Corp.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, management's assessment that Ultra Petroleum Corp. maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, Ultra Petroleum Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Ultra Petroleum Corp. as of December 31, 2006 and the related consolidated statements of operations and retained earnings, shareholders' equity, and cash flow for the year ended December 31, 2006 of Ultra Petroleum Corp. and our report dated February 26, 2007 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 26, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
Ultra Petroleum Corp.:

We have audited the accompanying consolidated balance sheet of Ultra Petroleum Corp. and subsidiaries as of December 31, 2005 and the related consolidated statements of operations and retained earnings, shareholders' equity, and cash flow for each of the years in the two-year period ended December 31, 2005. These consolidated 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 Ultra Petroleum Corp. and subsidiaries as of December 31, 2005, and the results of their operations and their cash flows for each of the years in the two-year period ended December 31, 2005, in accordance with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Denver, Colorado
March 30, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of Ultra Petroleum Corp.

We have audited the accompanying consolidated balance sheet of Ultra Petroleum Corp. as of December 31, 2006 and the related consolidated statement of operations and retained earnings, shareholders' equity, and cash flow for the year ended December 31, 2006. 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 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 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 audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Ultra Petroleum Corp. at December 31, 2006 and the consolidated results of their operations and their cash flows for year ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

As discussed in Notes 1 and 6 to the consolidated financial statements, Ultra Petroleum Corp. changed its method of accounting for Share-Based Payments in accordance with Statement of Financial Accounting Standards No. 123 (revised 2004) on January 1, 2006.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Ultra Petroleum Corp.'s internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2007 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 26, 2007

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ULTRA PETROLEUM CORP.

CONSOLIDATED BALANCE SHEETS

	December 31, 2006	December 31, 2005
	(Expressed in U.S. dollars)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 14,706,855	$ 44,394,775
Restricted cash	667,332	213,899
Accounts receivable	90,098,871	75,656,031
Deferred tax asset	8,266,499	—
Inventory	19,337,214	22,062,585
Prepaid drilling costs and other current assets	3,493,731	128,044
Total current assets	136,570,502	142,455,334
Oil and gas properties, using the full cost method of accounting		
Proved	1,048,307,743	612,960,790
Unproved	71,060,353	89,702,465
Capital assets	1,830,039	2,147,528
TOTAL ASSETS	$ 1,257,768,637	$ 847,266,117
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	$ 76,290,552	$ 49,297,861
Current taxes payable	6,842,057	3,564,990
Capital cost accrual	94,866,741	46,879,289
Total current liabilities	177,999,350	99,742,140
Long-term debt	165,000,000	—
Deferred income tax liability	259,191,252	155,746,465
Other long-term obligations	26,573,220	20,576,574
Shareholders' equity:		
Common stock — no par value; authorized — unlimited; issued and outstanding — 151,795,633 and 155,075,864 at December 31, 2006 and 2005, respectively	5,414,421	178,806,030
Treasury stock	(1,193,650)	(1,193,650)
Retained earnings	624,784,044	393,588,558
Total shareholders' equity	629,004,815	571,200,938
Commitments and contingencies (Note 12)		
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 1,257,768,637	$ 847,266,117

See accompanying notes to consolidated financial statements.

Approved on behalf of the Board:

/s/ Michael D. Watford, Chairman of the Board, Chief Executive Officer and President

/s/ Stephen J. McDaniel, Director

ULTRA PETROLEUM CORP.

CONSOLIDATED STATEMENTS OF OPERATIONS AND RETAINED EARNINGS

	Year Ended December 31, 2006	2005	2004
		(Expressed in U.S. Dollars)	
REVENUES:			
Natural gas sales	$ 470,324,244	$ 422,091,034	$ 224,207,694
Oil sales	122,343,339	94,401,967	34,838,753
	592,667,583	516,493,001	259,046,447
EXPENSES:			
Production expenses and taxes, excluding depreciation and amortization	110,008,894	89,601,686	50,869,283
Depletion, depreciation and amortization	93,498,556	58,102,871	30,249,061
General and administrative, excluding depreciation and amortization	14,935,103	14,342,178	7,075,720
	218,442,553	162,046,735	88,194,064
OPERATING INCOME	374,225,030	354,446,266	170,852,383
OTHER INCOME (EXPENSE):			
Interest income	1,943,121	612,153	90,760
Interest expense	(3,909,246)	(3,286,087)	(3,783,070)
	(1,966,125)	(2,673,934)	(3,692,310)
INCOME BEFORE INCOME TAXES	372,258,905	351,772,332	167,160,073
Income tax provision	141,063,419	123,472,085	58,010,278
NET INCOME	231,195,486	228,300,247	109,149,795
RETAINED EARNINGS, beginning of year	393,588,558	165,288,311	56,138,516
RETAINED EARNINGS, end of year	$ 624,784,044	$ 393,588,558	$ 165,288,311
NET INCOME PER COMMON SHARE — BASIC	$ 1.50	$ 1.49	$ 0.73
NET INCOME PER COMMON SHARE — DILUTED	$ 1.43	$ 1.41	$ 0.68
Weighted average common shares outstanding — basic	153,878,715	153,100,067	149,735,666
Weighted average common shares outstanding — diluted	161,614,570	161,943,400	161,205,534

See accompanying notes to consolidated financial statements.

ULTRA PETROLEUM CORP.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Shares Issued	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock	Total Shareholders' Equity
Balances at December 31, 2003	149,095,336	97,448,221	56,138,516	(2,940,357)	(1,193,650)	149,452,730
Stock options exercised	1,106,600	1,770,099	—	—	—	1,770,099
Employee stock plan grants	33,000	560,175	—	—	—	560,175
Fair value of non-employee stock option grants	—	100,550	—	—	—	100,550
Tax benefit of stock options exercised	—	6,634,807	—	—	—	6,634,807
Comprehensive earnings:						
Net earnings	—	—	109,149,795	—	—	109,149,795
Change in derivative instruments fair value	—	—	—	323,590	—	323,590
Total comprehensive earnings						109,473,385
Balances at December 31, 2004	150,234,936	106,513,852	165,288,311	(2,616,767)	(1,193,650)	267,991,746
Stock options exercised	4,793,700	20,266,680	—	—	—	20,266,680
Employee stock plan grants	47,228	1,389,380	—	—	—	1,389,380
Tax benefit of stock options exercised	—	50,636,118	—	—	—	50,636,118
Comprehensive earnings:						
Net earnings	—	—	228,300,247	—	—	228,300,247
Change in derivative instruments fair value	—	—	—	2,616,767	—	2,616,767
Total comprehensive earnings						230,917,014
Balances at December 31, 2005	155,075,864	178,806,030	393,588,558	—	(1,193,650)	571,200,938
Stock options exercised	655,900	9,202,730	—	—	—	9,202,730
Employee stock plan grants	33,401	2,141,003	—	—	—	2,141,003
Shares repurchased and retired	(3,969,532)	(197,551,398)	—	—	—	(197,551,398)
Fair value of employee stock option grants	—	2,313,534	—	—	—	2,313,534
Tax benefit of stock options exercised	—	10,502,522	—	—	—	10,502,522
Comprehensive earnings:						
Net earnings	—	—	231,195,486	—	—	231,195,486
Total comprehensive earnings						231,195,486
Balances at December 31, 2006	151,795,633	$ 5,414,421	$624,784,044	$ —	$(1,193,650)	$ 629,004,815

See accompanying notes to consolidated financial statements.

ULTRA PETROLEUM CORP.

CONSOLIDATED STATEMENTS OF CASH FLOW

	Year Ended December 31,		
	2006	2005	2004
Cash flows from operating activities:			
Net income	$ 231,195,486	$ 228,300,247	$ 109,149,795
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation and amortization	93,498,556	58,102,871	30,249,061
Deferred and current non-cash income taxes	105,680,810	69,270,977	57,748,452
Tax benefit of stock options exercised	—	50,636,118	—
Stock compensation	1,556,767	2,858,515	923,623
Excess tax benefit from stock based compensation	(10,502,522)	—	—
Net changes in working capital:			
Restricted cash	(453,433)	(1,938)	(1,292)
Accounts receivable	(14,442,840)	(39,906,744)	(16,400,426)
Inventory	664,409	(518,576)	(275,424)
Prepaid expenses and other current assets	(3,365,687)	1,597,799	(14,106)
Accounts payable and accrued liabilities	26,592,691	32,518,107	(10,169,082)
Other long-term obligations	2,155,923	7,931,130	3,870,179
Taxation payable	3,277,067	3,564,990	261,826
Net cash provided by operating activities	435,857,227	414,353,496	175,342,606
Cash flows from investing activities:			
Oil and gas property expenditures	(503,881,901)	(282,668,055)	(195,598,484)
Change in capital costs accrual	47,987,452	(6,239,096)	22,501,473
Inventory	1,677,260	(16,054,472)	9,037,557
Purchase of capital assets	(622,815)	(1,585,819)	(954,702)
Net cash (used in) investing activities	(454,840,004)	(306,547,442)	(165,014,156)
Cash flows from financing activities:			
Borrowings of long-term debt, gross	165,000,000	22,000,000	44,000,000
Payments on long-term debt, gross	—	(124,000,000)	(41,000,000)
Repurchased shares	(197,551,398)	—	—
Proceeds from issuance of common stock	9,202,730	20,266,680	1,770,099
Excess tax benefit from stock based compensation	10,502,522	—	—
Stock issued for compensation	2,141,003	1,389,380	—
Net cash (used in) provided by financing activities	(10,705,143)	(80,343,940)	4,770,099
Net (decrease)/increase in cash and cash equivalents	(29,687,920)	27,462,114	15,098,549
Cash and cash equivalents, beginning of year	44,394,775	16,932,661	1,834,112
Cash and cash equivalents, end of year	$ 14,706,855	$ 44,394,775	$ 16,932,661
SUPPLEMENTAL INFORMATION			
Cash paid for:			
Interest	$ 1,912,949	$ 3,393,279	$ 3,783,070
Income taxes	$ 21,379,990	$ 326,502	$ 153,905
Non-cash tax benefit of stock options exercised	—	$ 50,636,118	$ 6,634,807

See accompanying notes to consolidated financial statements.

ULTRA PETROLEUM CORP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Expressed in U.S. dollars unless otherwise noted)
Years ended December 31, 2006, 2005 and 2004

DESCRIPTION OF THE BUSINESS

Ultra Petroleum Corp. (the "Company") is an independent oil and natural gas company engaged in the acquisition, exploration, development, and production of oil and natural gas properties. The Company is incorporated under the laws of the Yukon Territory, Canada. The Company's principal business activities are in the Green River Basin of southwest Wyoming and Bohai Bay, China.

1. SIGNIFICANT ACCOUNTING POLICIES:

(a) *Basis of presentation and principles of consolidation:* The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries UP Energy Corporation, Ultra Resources, Inc. and Sino-American Energy Corporation. The Company presents its financial statements in accordance with U.S. Generally Accepted Accounting Principles ("GAAP"). All material inter-company transactions and balances have been eliminated upon consolidation.

(b) *Accounting principles:* The consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States.

(c) *Cash and cash equivalents:* We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents.

(d) *Restricted cash:* Restricted cash represents cash received by the Company from production sold where the final division of ownership of the production is unknown or in dispute. Wyoming law requires that these funds be held in a federally insured bank in Wyoming.

(e) *Capital assets:* Capital assets are recorded at cost and depreciated using the declining-balance method based on a seven-year useful life.

(f) *Oil and natural gas properties:* The Company uses the full cost method of accounting for exploration and development activities as defined by the Securities and Exchange Commission ("SEC"). Separate cost centers are maintained for each country in which the Company incurs costs. Under this method of accounting, the costs of unsuccessful, as well as successful, exploration and development activities are capitalized as properties and equipment. This includes any internal costs that are directly related to exploration and development activities but does not include any costs related to production, general corporate overhead or similar activities. Effective with the adoption of Statement of Financial Accounting Standard ("SFAS") No. 143, "Accounting for Asset Retirement Obligations" ("SFAS No. 143") in 2003, the carrying amount of oil and natural gas properties also includes estimated asset retirement costs recorded based on the fair value of the asset retirement obligation when incurred. Gain or loss on the sale or other disposition of oil and natural gas properties is not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas attributable to a country.

The sum of net capitalized costs and estimated future development costs of oil and natural gas properties are amortized using the units-of-production method based on the proven reserves as determined by independent petroleum engineers. Oil and natural gas reserves and production are converted into equivalent units based on relative energy content. Operating fees received related to the properties in which the Company owns an interest are netted against expenses. Fees received in excess of costs incurred are recorded as a reduction to the full cost pool. Effective with the adoption of SFAS No. 143, asset retirement obligations are included in the base costs for calculating depletion.

Oil and natural gas properties include costs that are excluded from capitalized costs being amortized. These amounts represent investments in unproved properties and major development projects. The Company excludes these costs on a country-by-country basis until proved reserves are found or until it is determined that the costs are impaired. All costs excluded are reviewed, at least quarterly, to determine if impairment has occurred. The amount of any impairment is transferred to the capitalized costs being amortized (the depreciation, depletion and amortization ("DD&A") pool) or a charge is made against earnings for those international operations where a reserve base has not yet been established. For international operations where a reserve base has not yet been established, an impairment requiring a charge to earnings may be indicated through evaluation of drilling results, relinquishing drilling rights or other information.

Companies that use the full cost method of accounting for oil and natural gas exploration and development activities are required to perform a ceiling test calculation each quarter. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X Rule 4-10. The ceiling test is performed quarterly on a country-by-country basis. The ceiling limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved crude oil and natural gas reserves discounted at 10% plus the lower of cost or market value of unproved properties less any associated tax effects. If such capitalized costs exceed the ceiling, the Company will record a write-down to the extent of such excess as a non-cash charge to earnings. Any such write-down will reduce earnings in the period of occurrence and result in lower DD&A expense in future periods. A write-down may not be reversed in future periods, even though higher oil and natural gas prices may subsequently increase the ceiling. The effect of implementing SFAS No. 143 had no effect on the ceiling test calculation as the future cash outflows associated with settling asset retirement obligations are excluded from this calculation.

(g) *Inventories:* Crude oil products and materials and supplies inventories are carried at the lower of current market value or cost. Inventory costs include expenditures and other charges directly and indirectly incurred in bringing the inventory to its existing condition and location and the Company uses the weighted average method of recording its inventory. Selling expenses and general and administrative expenses are reported as period costs and excluded from inventory cost. Inventories of materials and supplies are valued at cost or less. Crude oil product inventory at December 31, 2006 and 2005 includes depletion and lease operating expenses ("LOE") of $408,300 and $1,456,400, respectively, associated with the Company's crude oil production in China. At December 31, 2006, drilling and completion supplies inventory of $18.9 million primarily includes the cost of pipe that will be utilized during the 2007 drilling program.

(h) *Derivative transactions:* From time to time, the Company has entered into commodity price risk management transactions to manage its exposure to natural gas price volatility. These transactions are in the form of fixed price forward natural gas sales contracts with financial institutions and other creditworthy counterparties. These transactions have been designated by the Company as cash flow hedges. As such, unrealized gains and losses related to the change in fair market value of the derivative contracts are recorded in other comprehensive income in the balance sheet to the extent the hedges are effective.

(i) *Income taxes:* Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

(j) *Earnings per share:* Basic earnings per share is computed by dividing net earnings attributable to common stock by the weighted average number of common shares outstanding during each period. Diluted earnings per share is computed by adjusting the average number of common shares outstanding for the dilutive effect, if any, of common stock equivalents. The Company uses the treasury stock method to determine the dilutive effect.

ULTRA PETROLEUM CORP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table provides a reconciliation of the components of basic and diluted net income per common share for the years ended December 31, 2006, 2005 and 2004: (The earnings per share information (Basic income per common share and Diluted income per common share) have been updated to reflect the 2 for 1 stock split on May 10, 2005).

	Year Ended December 31, 2006	2005	2004
Net income	$ 231,195,486	$ 228,300,247	$ 109,149,795
Weighted average common shares outstanding during the period	153,878,715	153,100,067	149,735,666
Effect of dilutive instruments	7,735,855	8,843,333	11,469,868
Weighted average common shares outstanding during the period including the effects of dilutive instruments	161,614,570	161,943,400	161,205,534
Basic earnings per share	$ 1.50	$ 1.49	$ 0.73
Diluted earnings per share	$ 1.43	$ 1.41	$ 0.68
Number of shares not included in dilutive earnings per share that would have been anti-dilutive because the exercise price was greater than the average market price of the common shares	239,966	540,000	—

(k) *Use of estimates:* Preparation of consolidated financial statements in accordance with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the 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.

(l) *Accounting for share-based compensation:* On January 1, 2006, the Company adopted Statement of Financial Accounting Standards No. 123 (revised 2004), “Share-Based Payment” (“SFAS No. 123R”) which requires the measurement and recognition of compensation expense for all share-based payment awards made to employees and directors including employee stock options based on estimated fair values. SFAS No. 123R supersedes the Company’s previous accounting under Accounting Principles Board Opinion No. 25, “Accounting for Stock Issued to Employees” (“APB No. 25”) for periods beginning in fiscal year 2006. In March 2005, the SEC issued Staff Accounting Bulletin No. 107 (“SAB 107”) relating to SFAS No. 123R. The Company has applied the provisions of SAB 107 in its adoption of SFAS No. 123R.

The Company adopted SFAS No. 123R using the modified prospective transition method, which requires the application of the accounting standard as of January 1, 2006, the first day of the Company’s fiscal year 2006. The Company’s Consolidated Financial Statements as of and for the year-ended December 31, 2006 reflect the impact of SFAS No. 123R. In accordance with the modified prospective transition method, the Company’s Consolidated Financial Statements for prior periods have not been restated to reflect, and do not include, the impact of SFAS No. 123R. Share-based compensation expense recognized under SFAS No. 123R for the year- ended December 31, 2006 was $1,156,767, which consisted of stock-based compensation expense related to employee stock options. There was no stock-based compensation expense related to employee stock options recognized during the year-ended December 31, 2005.

SFAS No. 123R requires companies to estimate the fair value of share-based payment awards on the date of grant using an option-pricing model. The value of the portion of the award that is ultimately expected to vest is recognized as expense over the requisite service periods in the Company’s Consolidated Statement of Operations.

Under SFAS No. 123R, share-based compensation expense recognized during the period is based on the value of the portion of share-based payment awards that is ultimately expected to vest during the period. Share-based compensation expense recognized in the Company's Consolidated Statement of Operations for the year-ended December 31, 2006 includes compensation expense for share-based payment awards granted subsequent to January 1, 2006 based on the grant date fair value estimated in accordance with the provisions of SFAS No. 123R. As of December 31, 2005, all stock options granted to date had fully vested. Compensation expense attributable to awards granted subsequent to January 1, 2006 is recognized using the straight-line method. As share-based compensation expense recognized in the Consolidated Statement of Operations for the year-ended December 31, 2006 is based on awards ultimately expected to vest, it has been reduced for estimated forfeitures. SFAS No. 123R requires forfeitures to be estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates. In the Company's pro forma information required under SFAS No. 123 for the periods prior to January 1, 2006, the Company accounted for forfeitures as they occurred.

Under SFAS No. 123 (and APB No. 25), the Company utilized a Black-Scholes option pricing model to measure the fair value of stock options granted to employees. For additional information, see Note 6. The Company's determination of fair value of share-based payment awards on the date of grant using an option-pricing model is affected by the Company's stock price as well as assumptions regarding a number of highly complex and subjective variables. These variables include, but are not limited to, the Company's expected stock price volatility over the term of the awards, and actual and projected employee stock option exercise behaviors.

Option-pricing models were developed for use in estimating the value of traded options that have no vesting or hedging restrictions and are fully transferable. Because (1) the Company's employee stock options have certain characteristics that are significantly different from traded options, and (2) changes in the subjective assumptions can materially affect the estimated value, in management's opinion, the existing valuation models may not provide an accurate measure of the fair value of the Company's employee stock options. Although the fair value of employee stock options is determined in accordance with SFAS No. 123R and SAB 107 using a Black-Scholes option-pricing model, that value may not be indicative of the fair value observed in a willing buyer/willing seller market transaction. The Company is responsible for determining the assumptions used in estimating the fair value of its share-based payment awards.

Prior to adopting of SFAS No. 123R on January 1, 2006, the Company followed Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation" ("SFAS No. 123") which allowed for the continued measurement of compensation cost for such plans using the intrinsic value based method prescribed by APB Opinion No. 25 provided that pro forma results of operations were disclosed for those options granted. Accordingly, the Company accounted for stock options granted to employees and directors of the Company under the intrinsic value method. Had the Company reported compensation costs as determined by the fair value method of accounting for option grants to employees and directors, net income and net income per common share would approximate the following pro forma amounts: (The earnings per share amounts have been adjusted to reflect the 2 for 1 stock split on May 10, 2005).

ULTRA PETROLEUM CORP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	For the Year Ended December 31,	
	2005	2004
Net income:		
As reported	$ 228,300,247	$ 109,149,795
Deduct: Fair value of stock options issued, net of tax	(13,511,140)	(17,714,486)
Pro forma	$ 214,789,107	$ 91,435,309
Net income per common share:		
Basic earnings per share:		
As reported	$ 1.49	$ 0.73
Pro forma	$ 1.40	$ 0.61
Diluted earnings per share:		
As reported	$ 1.41	$ 0.68
Pro forma	$ 1.33	$ 0.57

For purposes of pro forma disclosures, the estimated fair value of options is amortized to expense over the options' vesting period. The weighted-average fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with the following assumptions:

	For the Year Ended	
	2005	2004
Expected volatility	34.8 - 44.9%	38.4%
Expected dividends	0.0%	0.0%
Expected term (in years)	1.9	6.50
Risk free rate	4.18% - 4.41%	3.71%
Expected forfeiture rate	Actual forfeitures	Actual forfeitures

(m) *Revenue Recognition.* Within the Company's United States segment, natural gas revenues are recorded on the entitlement method. Under the entitlement method, revenue is recorded when title passes based on the Company's net interest. The Company records its entitled share of revenues based on estimated production volumes. Subsequently, these estimated volumes are adjusted to reflect actual volumes that are supported by third party pipeline statements or cash receipts. Since there is a ready market for natural gas, the Company sells the majority of its products soon after production at various locations at which time title and risk of loss pass to the buyer. Natural gas imbalances occur when the Company sells more or less than its entitled ownership percentage of total natural gas production. Any amount received in excess of the Company's share is treated as a liability. If the Company receives less than its entitled share, the underproduction is recorded as a receivable. At December 31, 2006 the Company had a net natural gas imbalance liability of $1.7 million and at December 31, 2005, the Company had a net natural gas imbalance liability of $0.5 million.

In China, revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title is transferred.

(n) *Accumulated Other Comprehensive Earnings (Loss):* Other comprehensive earnings (loss) is a term used to define revenues, expenses, gains and losses that under generally accepted accounting principles are reported as separate components of Shareholders' Equity instead of net earnings (loss).

ULTRA PETROLEUM CORP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Year Ended December 31, 2006	2005	2004
Net income	$ 231,195,486	$ 228,300,247	$ 109,149,795
Unrealized loss on derivative instruments, net of tax	—	—	(2,616,767)
Pro Forma , including the effect of dilutive instruments	$ 231,195,486	$ 228,300,247	$ 106,533,028

(o) *Impact of recently issued accounting pronouncements:* As of January 1, 2006, the Company adopted SFAS No. 154, "Accounting for Changes and Error Corrections, a replacement of APB Opinion No. 20 and SFAS No. 3" ("SFAS No. 154"). SFAS No. 154 requires retrospective application of voluntary changes in accounting principles, unless it is impracticable. The adoption of this standard did not have a material impact on consolidated results of operations, financial position or liquidity.

In July 2006, the Financial Accounting Standards Board ("FASB") issued Interpretation No. 48 ("FIN No. 48"), "Accounting for Uncertainty in Income Taxes, an Interpretation of SFAS No. 109," which clarifies the accounting for uncertainty in income taxes in accordance with SFAS No. 109, "Accounting for Income Taxes." FIN No. 48 prescribes a recognition threshold and measurement attribute for the measurement and financial statement recognition of a tax position taken or expected to be taken in a tax return. The interpretation also provides guidance on de-recognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. Upon adoption, FIN No. 48 will be applied to all tax positions in those tax years for which the tax return statute of limitations is open. The cumulative effect of the initial application will be reported as an increase or decrease to retained earnings as of the beginning of the period in which it is adopted. For the Company, the provisions of FIN No. 48 are effective January 1, 2007. The Company has not completed its evaluation of the impact FIN No. 48 will have when adopted. However, the Company currently believes that its implementation will not have a material impact on consolidated results of operations, financial position or liquidity.

In September 2006, the SEC staff issued Staff Accounting Bulletin 108, "Financial Statements — Considering the Effects of Prior Year Misstatements When Quantifying Misstatements in Current Year Financial Statements" ("SAB 108"). SAB 108 addresses how a registrant should quantify the effect of an error on the financial statements and concludes that a dual approach should be used to compute the amount of a misstatement. Specifically, the amount should be computed using both the "rollover" (current year income statement perspective) and "iron curtain" (year-end balance sheet perspective) methods. For the Company, the provisions of SAB 108 were effective January 1, 2006. The implementation of SAB 108 did not have a material impact on the Company's consolidated results of operations, financial position or liquidity.

2. ASSET RETIREMENT OBLIGATIONS:

In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations" ("SFAS No. 143"). SFAS No. 143 requires the Company to record the fair value of an asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development and/or normal use of the assets. As of December 31, 2006, the Company has recorded a liability of $7,442,071 ($6,130,672 U.S. and $1,311,399 China) to account for future obligations associated with its assets in both the United States and China. As of December 31, 2005, the liability was $3,601,348 ($2,845,724 U.S. and $755,624 China).

ULTRA PETROLEUM CORP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table summarizes the activities for the Company's asset retirement obligations for the year ended December 31, 2006:

	December 31, 2006
Asset retirement obligations at beginning of period	$ 3,601,348
Accretion expense	280,725
Liabilities incurred	1,681,865
Liabilities settled	—
Revisions of estimated liabilities	1,878,133
Asset retirement obligations at end of period	7,442,071
Less: current asset retirement obligations	—
Long-term asset retirement obligations	$ 7,442,071

3. OIL AND GAS PROPERTIES:

	December 31, 2006	December 31, 2005
Developed Properties:		
Acquisition, equipment, exploration, drilling and environmental costs — Domestic	$ 1,174,683,088	$ 700,425,880
Acquisition, equipment, exploration, drilling and environmental costs — China	96,873,985	43,890,413
Less accumulated depletion, depreciation and amortization — Domestic	(196,683,521)	(118,172,467)
Less accumulated depletion, depreciation and amortization — China	(26,565,809)	(13,183,036)
	1,048,307,743	612,960,790
Unproven Properties:		
Acquisition and exploration costs — Domestic	28,997,935	17,647,300
Acquisition and exploration costs — China	42,062,418	72,055,165
	$ 1,119,368,096	$ 702,663,255

The Company holds interests in projects located in both the United States and in China. Costs related to these interests of $71.1 million ($29.0 million in the U.S. and $42.1 million in China) are not being depleted pending determination of existence of estimated proved reserves. The Company's share of exploration on its China properties accounts for the majority of this balance. The properties in China began producing in July 2004 and development of additional fields continues along with exploration of future fields. The Company will continue to assess and allocate the unproven properties over the next several years as proved reserves are established and as exploration dictates whether or not future areas will be developed.

	Total	2006	2005	2004	Prior
United States:					
Acquisition costs	$ 31,386,056	$ 12,779,651	$ 1,818,954	$ 222,685	$ 16,564,766
Exploration costs	7,629,315	151,428	545,602	1,082,804	5,849,481
Less transfers to proved	(10,017,436)	(1,580,444)	(1,627,266)	—	(6,809,726)
	28,997,935	11,350,635	737,290	1,305,489	15,604,521
China:					
Acquisition costs	44,857,346	—	—	—	44,857,346
Exploration costs	74,826,615	6,915,587	19,167,259	29,390,964	19,352,805
Less transfers to proved	(77,621,543)	(36,908,334)	(19,041,544)	(21,671,665)	—
	42,062,418	(29,992,747)	125,715	7,719,299	64,210,151
Total	$ 71,060,353	$ (18,642,112)	$ 863,005	$ 9,024,788	$ 79,814,672

4. CAPITAL ASSETS:

	December 31, 2006 Cost	December 31, 2006 Accumulated Depreciation	December 31, 2006 Net Book Value	December 31, 2005 Net Book Value
Computer equipment	$ 1,293,655	$ (826,760)	$ 466,895	$ 311,884
Office equipment	329,266	(206,086)	123,180	88,385
Field equipment	1,782,387	(841,318)	941,069	1,025,915
Other	2,482,916	(2,184,021)	298,895	721,344
	$ 5,888,224	$ (4,058,185)	$ 1,830,039	$ 2,147,528

5. LONG-TERM LIABILITIES:

	December 31, 2006	December 31, 2005
Bank indebtedness	$ 165,000,000	$ —
Other long-term obligations	26,573,220	20,576,574
	$ 191,573,220	$ 20,576,574

Bank indebtedness: The Company (through its subsidiary) participates in a revolving credit facility with a group of banks led by JP Morgan Chase Bank, N.A. The agreement specifies a maximum loan amount of $500.0 million, an aggregate borrowing base of $1.1 billion and a commitment amount of $200.0 million at December 31, 2006. The commitment amount may be increased up to the lesser of the borrowing base amount or $500.0 million at any time at the request of the Company. Each bank shall have the right, but not the obligation, to increase the amount of their commitment as requested by the Company. In the event that the existing banks increase their commitment to an amount less than the requested commitment amount, then it would be necessary to bring additional banks into the facility. At December 31, 2006, the Company had $165.0 million outstanding and $35.0 million unused and available under the current committed amount.

The credit facility matures on May 1, 2010. The note bears interest at either (A) the bank's prime rate plus a variable margin ranging from zero percent (0.00%) to three-quarters of one percent (0.75%) based on the percentage of available credit drawn or at (B) LIBOR plus a variable margin ranging from one percent (1.00%) to one and three-quarters of one percent (1.75%) based on the percentage of available credit drawn. For purposes of calculating interest, the available credit is equal to the borrowing base. An average annual commitment fee of 0.25% to 0.375%, depending on the percentage of available credit drawn, is charged quarterly for any unused portion of the commitment amount. The Company's total commitment fees were $377,173, $354,017 and $374,096 for the years ended December 31, 2006, 2005 and 2004, respectively.

The borrowing base is subject to periodic (at least semi-annual) review and re-determination by the banks and may be decreased or increased depending on a number of factors, including the Company's proved reserves and the bank's forecast of future oil and natural gas prices. If the borrowing base is reduced to an amount less than the balance outstanding, the Company has sixty days from the date of written notice of the reduction in the borrowing base to pay the difference. Additionally, the Company is subject to quarterly reviews of compliance with the covenants under the bank facility including minimum coverage ratios relating to interest, working capital and advances to Sino-American Energy Corporation. In the event of a default under the covenants, the Company may not be able to access funds otherwise available under the facility. As of December 31, 2006, the Company was in compliance with required covenants of the bank facility.

Any debt outstanding under the credit facility is secured by a majority of the Company's proved domestic oil and natural gas properties.

Other long-term obligations: These costs relate to the long-term portion of production taxes payable, a liability associated with imbalanced production, our asset retirement obligations mentioned in Note 2 and the long-term portion of the Company's incentive compensation plan.

6. SHARE BASED COMPENSATION:

The Company's Stock Incentive Plans are administered by the Compensation Committee of the Board of Directors (the "Plan Administrator"). The Plan Administrator may make awards of stock options to employees, directors, officers and consultants of the Company as long as the aggregate number of common shares issuable to any one person pursuant to incentives does not exceed 5% of the number of common shares outstanding at the time of the award. In addition, no participant may receive during any fiscal year of the Company's awards of incentives covering an aggregate of more than 500,000 common shares. The Plan Administrator determines the vesting requirements and any vesting restrictions or forfeitures that occur in certain circumstances. Incentives may not have an exercise period longer than 10 years. The exercise price of the stock may not be less than the fair market value of the common shares at the time of award, where "fair market value" means the average high and low trading price of the common shares on the date of the award.

On April 29, 2005, the shareholders approved the adoption of the 2005 Stock Incentive Plan (the "2005 Stock Incentive Plan"). The 2005 Stock Incentive Plan authorizes the Plan Administrator to award incentives from the effective date of the 2005 Stock Incentive Plan. The 2005 Stock Incentive Plan is in addition to the Company's existing stock option plans (the "2000 Option Plan" and the "1998 Stock Plan"). The 2000 Option Plan and the 1998 Stock Plan remain effective and the Company will make grants under each of the existing plans.

The purpose of the 2005 Stock Incentive Plan is to foster and promote the long-term financial success of the Company and to increase shareholder value by attracting, motivating and retaining key employees, consultants and directors and providing such participants in the 2005 Stock Incentive Plan with a program for obtaining an ownership interest in the Company that links and aligns their personal interests with those of the Company's shareholders, thus enabling such participants to share in the long-term growth and success of the Company. To accomplish these goals, the 2005 Stock Incentive Plan permits the granting of incentive stock options, non-statutory stock options, stock appreciation rights, restricted stock, and other stock-based awards, some of which may require the satisfaction of performance-based criteria in order to be payable to participants. The 2005 Stock Incentive Plan is an important component of the total compensation package offered to employees and directors, reflecting the importance that the Company places on motivating and rewarding superior results with long-term, performance-based incentives.

The purposes of the 2000 Option Plan and the 1998 Stock Plan are: (i) to associate the interests of management of the Company and its subsidiaries and affiliates closely with the stockholders to generate an increased incentive to contribute to the Company's future success and prosperity, thus enhancing the value of the Company for the benefit of its stockholders; (ii) to maintain competitive compensation levels thereby attracting and retaining highly competent and talented directors, employees and consultants; and (iii) to provide an incentive to such management for continuous employment with the Company.

Accounting for share-based compensation

In December 2004, the FASB issued SFAS No. 123R. SFAS No. 123R is a revision of SFAS No. 123 and supersedes APB No. 25. Among other items, SFAS No. 123R eliminates the use of APB No. 25 and the intrinsic value method of accounting, and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments, based on the grant date fair value of those awards, in the financial statements. Pro forma disclosure is no longer an alternative under the new standard. Accordingly, the Company adopted SFAS No. 123R as of January 1, 2006.

SFAS No. 123R provides specific guidance on income tax accounting and clarifies how SFAS No. 109, "Accounting for Income Taxes," should be applied to stock-based compensation. For example, the expense for certain types of option grants is only deductible for tax purposes at the time that the taxable event takes place, which could cause variability in the Company's effective tax rates recorded throughout the year. SFAS No. 123R does not allow companies to "predict" when these taxable events will take place. Furthermore, it requires that the benefits associated with the tax deductions in excess of recognized compensation cost be reported as a financing cash flow, rather than as an operating cash flow as required under SFAS No. 123. These future amounts cannot be estimated, because they depend on, among other things, when employees exercise stock options.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Valuation and Expense Information under SFAS 123R

The following table summarizes share-based compensation expense related to employee stock options under SFAS 123R for the year ended December 31, 2006 which was allocated as follows:

	Year-Ended December 31, 2006
Total cost of share-based payment plans	$ 2,313,534
Amounts capitalized in inventory and oil and gas properties	1,156,767
Amounts recognized in income for amounts previously capitalized in inventory and fixed assets	—
Amounts charged against income, before income tax benefit	$ 1,156,767
Amount of related income tax benefit recognized in income	$ 406,025
Impact from adoption of SFAS No. 123R on:	
Income from continuing operations	$ 1,156,767
Income before income taxes	$ 1,156,767
Net income	$ 750,742
Cash flow from operations	$ (10,502,522)
Cash flow from financing activities	$ 10,502,522
Basic earnings per share	—
Diluted earnings per share	—

The fair value of each share option award is estimated on the date of grant using a Black-Scholes pricing model based on assumptions noted in the following table. The Company's employee stock options have various restrictions including vesting provisions and restrictions on transfers and hedging, among others, and are often exercised prior to their contractual maturity. Expected volatilities used in the fair value estimate are based on historical volatility of the Company's stock. The Company uses historical data to estimate share option exercises, expected term and employee departure behavior used in the Black-Scholes pricing model. Groups of employees (executives and non-executives) that have similar historical behavior are considered separately for purposes of determining the expected term used to estimate fair value. The assumptions utilized result from differing pre- and post-vesting behaviors among executive and non-executive groups. The risk-free rate for periods within the contractual term of the share option is based on the U.S. Treasury yield curve in effect at the time of grant.

	Non-Executives	Executives
Expected volatility	43.7-45.8%	43.5-47.4%
Expected dividends	0%	0%
Expected term (in years)	2.75-4.71	3.58-5.55
Risk free rate	4.51-5.03%	4.76-4.84%
Expected forfeiture rate	20.0%	20.0%

Securities Authorized for Issuance Under Equity Compensation Plans

As of December 31, 2006, the Company had the following securities issuable pursuant to outstanding award agreements or reserved for issuance under the Company's previously approved stock incentive plans. (Upon exercise, shares issued will be newly issued shares).

Plan Category	Number of Securities to Be Issued Upon Exercise of Outstanding Options	Weighted-Average Exercise Price of Outstanding Options	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in the First Column)
Equity compensation plans approved by security holders	9,082,756	$ 10.62	10,739,034
Equity compensation plans not approved by security holders	n/a	n/a	n/a
Total	9,082,756	$ 10.62	10,739,034

Changes in Stock Options and Stock Options Outstanding

The following table summarizes the changes in stock options for the three-year period ended December 31, 2006:

	Number of Options	Weighted Average Exercise Price (US$)
Balance, December 31, 2003	11,805,000	$ 0.26 to $7.10
Granted	2,005,000	$ 11.69 to $24.31
Exercised	(1,106,600)	$ 0.38 to $7.10
Balance, December 31, 2004	12,703,400	$ 0.26 to $24.31
Granted	1,529,000	$ 23.90 to $58.71
Exercised	(4,793,700)	$ 0.32 to $25.68
Cancelled	(50,000)	$ 25.68 to $25.68
Balance, December 31, 2005	9,388,700	$ 0.26 to $58.71
Granted	379,966	$ 46.05 to $67.73
Exercised	(655,900)	$ 0.46 to $40.00
Cancelled	(30,010)	$ 16.97 to $63.05
Balance, December 31, 2006	9,082,756	$ 0.26 to $67.73

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following tables summarize information about the stock options outstanding at December 31, 2006:

Range of Exercise Price ($US)	Options Outstanding: Number Outstanding	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price ($US)	Aggregate Intrinsic Value ($US)
$0.38 - 0.46	2,577,500	2.08	$ 0.46	$ 121,864,398
$0.25 - 0.57	760,000	3.29	$ 0.34	$ 36,025,200
$1.49 - 2.61	1,355,000	4.21	$ 1.90	$ 62,109,550
$3.91 - 4.43	657,500	5.36	$ 4.40	$ 28,498,425
$4.83 - 7.10	856,600	6.36	$ 5.05	$ 36,569,320
$11.68 - 24.21	1,298,500	7.31	$ 15.89	$ 41,361,355
$23.90 - 58.71	1,199,700	8.49	$ 35.93	$ 15,181,956
$46.05 - 67.73	377,956	9.53	$ 56.76	$ 44,800

Range of Exercise Price ($US)	Options Exercisable: Number Exercisable	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price ($US)	Aggregate Intrinsic Value ($US)
$0.38 - 0.46	2,577,500	2.08	$ 0.46	$ 121,864,398
$0.25 - 0.57	760,000	3.29	$ 0.34	$ 36,025,200
$1.49 - 2.61	1,355,000	4.21	$ 1.90	$ 62,109,550
$3.91 - 4.43	657,500	5.36	$ 4.40	$ 28,498,425
$4.83 - 7.10	856,600	6.36	$ 5.05	$ 36,569,320
$11.68 - 24.21	1,298,500	7.31	$ 15.89	$ 41,361,355
$23.90 - 58.71	1,199,700	8.49	$ 35.93	$ 15,181,956
$46.05 - 67.73	—	—	—	—

The aggregate intrinsic value in the preceding tables represents the total pre-tax intrinsic value, based on the Company's closing stock price of $47.74 on December 31, 2006, which would have been received by the option holders had all option holders exercised their options as of that date. The total number of in-the-money options exercisable as of December 31, 2006 was 8,494,800.

The weighted-average grant-date fair value of share options granted during the year ended December 31, 2006 was $23.65 per share. The total intrinsic value of share options exercised during the year ended December 31, 2006 was $28.7 million.

At December 31, 2006, there was $4,875,767 of total unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the Stock Incentive Plans. That cost is expected to be recognized over a weighted average period of 2.4 years.

PERFORMANCE SHARE PLANS:

Long-Term Incentive Plan

In 2005, the Company adopted a Long-Term Incentive Plan ("LTIP") in order to further align the interests of key employees with shareholders and give key employees the opportunity to share in the long-term performance of the Company by achieving specific corporate financial and operational goals. Under the LTIP, the Compensation Committee establishes certain performance measures at the beginning of each three-year overlapping performance period. Performance measures may vary for performance periods. In the event of a change of control of the

Company all outstanding awards are paid at maximum levels in cash. The event of a change of control is not currently probable.

Each participant in the LTIP is assigned threshold, target and maximum award levels that are expressed as a percentage of his or her base salary. Selected officers, managers and other key employees are eligible to participate in the LTIP. Participants are recommended by the CEO and approved by the Compensation Committee and are assigned to a specific eligibility level. The participation levels are as follows (the respective percentage award is calculated based upon the participant's base salary at the beginning of the award period), (i) if threshold performance objectives are attained, the incentive award opportunities range from 6% to 38%; (ii) if target performance objectives are attained, the incentive award opportunities range from 20% to 125%; and (iii) if maximum performance objectives are attained, the incentive award opportunities range from 30% to 188%. The threshold award level is not the minimum award, but is the award at the threshold performance level. Awards are expressed as dollar targets and become payable in common shares issued under the Company's stock incentive plans at the end of each three-year performance period based on the overall performance of the Company during such period. A new three-year period begins each January, beginning January 1, 2005. Participants must be employed by the Company at payment date in order to receive an award. Employees joining the Company after January 1, 2005 will participate on a pro rata basis based on their length of employment during the performance period.

The Compensation Committee has established the following performance measures for the 2005 LTIP and 2006 LTIP: return on equity, reserve replacement ratio, and production growth. At the discretion of the Compensation Committee, additional metrics may be added to individual participants.

For the twelve months ended December 31, 2006, the Company recognized $736,486 and $747,908 associated with the 2005 LTIP and 2006 LTIP, respectively. Of the total, $405,068 and $373,951 was recognized in pre-tax compensation expense related to the 2005 LTIP and 2006 LTIP, respectively. The remaining $331,418 and $373,957 associated with the 2005 LTIP and 2006 LTIP, respectively, was capitalized in Oil and Gas Properties. The amounts recognized during 2006 assume that maximum performance objectives are attained. If the Company ultimately attains maximum performance objectives, the associated total compensation expense, estimated at December 31, 2006, for the three year performance periods would be approximately $2.1 million and $2.2 million (before taxes) related to the 2005 LTIP and 2006 LTIP, respectively.

Best in Class

In 2005, the Company also established a Best in Class program for all full-time employees of the Company, including executive officers. The purpose of the program is to recognize and financially reward the collective efforts of all the Company's employees in achieving sustained industry leading performance and the enhancement of shareholder value. In the event of a change of control of the Company all outstanding awards become 150% vested. The event of a change of control is not currently probable.

Under the Best in Class program, on January 1, 2005 or the employment date if subsequent to January 1, 2005, all employees of the Company received a contingent award of stock units equal to $50,000 worth of the Company's common stock based on the average of the high and low share price on the date of grant. Employees joining the Company after January 1, 2005 will participate on a pro rata basis based on their length of employment during the performance period. The number of units that will vest and become payable is based on the Company's performance relative to the industry during a three-year performance period beginning January 1, 2005 and ending December 31, 2007 and are set at threshold (50%), target (100%) and maximum (150%) levels. For each vested unit, the participant will receive one share of common stock.

The emphasis of this plan is to recognize and reward the Company's employees for performance that is recognized in the industry as clearly outstanding. Performance metrics will be developed and measured by an accepted third party research organization. The total vested award will be the sum of the vesting percentage for each metric. The maximum units that may be vested is 150% of the original award. Performance results will be determined after the end of the performance period and publication of the applicable industry reports. A participant must be employed when payments are made in order to receive an award.

For the year ended December 31, 2006, the Company recognized $544,168 associated with the Best in Class Incentive Compensation Program. Of the total, $290,489 was recognized as pre-tax compensation expense while the remaining $253,679 was capitalized in Oil and Gas Properties. The amount recognized during 2006 assumes that target performance levels are achieved. If the Company ultimately attains the target performance level, the associated total compensation expense, estimated at December 31, 2006, for the entire three year performance period would be approximately $2.1 million before income taxes.

7. DERIVATIVE FINANCIAL INSTRUMENTS:

The Company's major market risk exposure is in the pricing applicable to its natural gas and oil production. Realized pricing is currently driven primarily by the prevailing price for the Company's Wyoming natural gas production. Historically, prices received for natural gas production have been volatile and unpredictable. Pricing volatility is expected to continue. Natural gas price realizations ranged from a monthly low of $4.50 per Mcf to a monthly high of $8.26 per Mcf during 2006. Realized natural gas prices are derived from the financial statements which include the effects of hedging and natural gas balancing.

The Company primarily relies on fixed price forward natural gas sales to manage its commodity price exposure. These fixed price forward natural gas sales are considered normal sales. The Company may, from time to time and to a lesser extent, use derivative instruments as one way to manage its exposure to commodity prices. The Company has periodically entered into fixed price to index price swap agreements in order to hedge a portion of its production. The oil and natural gas reference prices of these commodity derivatives contracts are based upon crude oil and natural gas futures, which have a high degree of historical correlation with actual prices the Company receives. Under Statement of Financial Accounting Standard No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS No. 133"), all derivative instruments are recorded on the balance sheet at fair value. Changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. For qualifying cash flow hedges, the gain or loss on the derivative is deferred in accumulated other comprehensive income (loss) to the extent the hedge is effective. For qualifying fair value hedges, the gain or loss on the derivative is offset by related results of the hedged item in the income statement. Gains and losses on hedging instruments included in accumulated other comprehensive income (loss) are reclassified to oil and natural gas sales revenue in the period that the related production is delivered. Derivative contracts that do not qualify for hedge accounting treatment are recorded as derivative assets and liabilities at market value in the consolidated balance sheet, and the associated unrealized gains and losses are recorded as current expense or income in the consolidated statement of operations. The Company currently does not have any derivative contracts in place that do not qualify as a cash flow hedge.

The Company to a larger extent utilizes fixed price forward natural gas sales contracts at southwest Wyoming delivery points to manage its commodity exposure. At December 31, 2006, the Company had no open derivative contracts to manage price risk on its natural gas production. The Company had the following fixed price physical delivery contracts in place on behalf of its interest and those of other parties at December 31, 2006. (The Company's approximate average net interest in physical gas sales is 80%.)

Contract Period	Volume MMbtu/Day	Average Price/MMbtu
April 2007 — October 2007	40,000	$ 6.20

Subsequent to December 31, 2006 and through February 26, 2007, the Company has entered into the following fixed price physical delivery contracts on behalf of its interest and those of other parties:

Contract Period	Volume MMbtu/Day	Average Price/MMbtu
Calendar 2008	60,000	$ 6.63

8. SHARE REPURCHASE PROGRAM:

On May 17, 2006, the Company announced that its Board of Directors authorized a share repurchase program for up to an aggregate $1 billion of the Company's outstanding common stock which has been and will be funded by cash on hand and the Company's senior credit facility. Pursuant to this authorization, the Company has commenced an initial program to purchase up to $250.0 million of the Company's outstanding shares through open market transactions or privately negotiated transactions.

Ultra Petroleum Corp. (Ultra Petroleum) owns 100% of UP Energy Corporation (UP Energy), which in turn owns 100% of Ultra Resources, Inc. (Ultra Resources). Ultra Resources may, from time to time, repurchase Ultra Petroleum publicly traded stock. On settlement, the repurchased stock will be transferred to Ultra Resources. The stock repurchase will be funded with cash held in an Ultra Resources bank account or the Company's senior credit facility.

At December 31, 2006, the Company had repurchased 3,969,532 shares of its common stock for an aggregate $197.6 million at a weighted average price of $49.77 per share.

9. INCOME TAXES:

Income before income taxes is as follows:

	Year Ended December 31, 2006	2005	2004
United States	$ 320,034,244	$ 304,943,491	$ 153,553,816
Foreign	52,224,661	46,828,841	13,606,257
Total	$ 372,258,905	$ 351,772,332	$ 167,160,073

The consolidated income tax provision is comprised of the following:

	Year Ended December 31, 2006	2005	2004
Current:			
U.S. federal & state	$ 26,944,004	$ 50,636,118	$ 261,826
Foreign	18,941,127	3,564,990	—
Deferred:			
U.S. federal & state	95,178,288	57,228,294	53,144,257
Foreign	—	12,042,683	4,604,195
Total income tax provision	$ 141,063,419	$ 123,472,085	$ 58,010,278

During 2006 and 2005, the Company realized tax benefits of $10.5 million and $50.6 million, respectively, attributable to tax deductions associated with the exercise of stock options. These benefits reduce the amount of the Company's U.S. federal and state cash tax payments and are recorded as a reduction of current taxes payable and as an increase in shareholders' equity.

The income tax provision differs from the amount that would be computed by applying the U.S. federal income tax rate of 35% to pretax income as a result of the following:

	Year Ended December 31, 2006	2005	2004
Income tax provision computed at the U.S. statutory rate	$ 130,290,617	$ 123,120,316	$ 58,506,026
State income tax provision net of federal benefit	150,248	297,319	159,628
Withholding tax on share repurchase transactions	10,400,543	—	—
Other, net	222,011	54,450	(655,376)
	$ 141,063,419	$ 123,472,085	$ 58,010,278

During 2006, the Company incurred U.S. withholding taxes totaling $10.4 million in connection with the repurchase of 3,969,532 shares of its common stock. (See Note 8).

The tax effects of temporary differences that give rise to significant components of the Company's deferred tax assets and liabilities are as follows:

	Year Ended December 31, 2006	2005
Deferred tax assets:		
U.S. federal tax credit carryforwards	$ 7,101,181	$ —
Canadian net operating loss carryforwards	1,474,648	1,976,930
Other, net	1,165,318	4,469
	9,741,147	1,981,399
Valuation allowance	(1,474,648)	(1,976,930)
Net deferred tax assets	8,266,499	4,469
Deferred tax liabilities:		
Property and equipment	(259,191,252)	(155,750,934)
Net deferred tax asset (liability)	$ (250,924,753)	$ (155,746,465)

In assessing the realizability of the deferred tax assets, management considers whether it is more likely than not that some or all of the deferred tax assets will not be realized. The ultimate realization of the deferred tax assets is dependent upon the generation of future taxable income during the periods in which the temporary differences become deductible. Among other items, management considers the scheduled reversal of deferred tax liabilities, projected future taxable income and available tax planning strategies.

As of December 31, 2006, the Company had approximately $6.0 million and $1.1 million of U.S. federal alternative minimum tax credit and foreign tax carryforwards, respectively ("Tax Credits"). The Tax Credits are available to offset future U.S. income taxes. None of the Tax Credits expire prior to 2017. The Company has not recorded any valuation allowance attributable to its Tax Credits as management estimates that it is more likely than not that the Tax Credits will be fully utilized before they expire.

As of December 31, 2004, the Company had U.S. federal regular tax net operating loss carryforwards ("NOL's") of approximately $16.7 million which were available to offset future U.S. taxable income. The Company did not record any valuation allowance attributable to its U.S. NOL's as management estimated that it was more likely than not that the U.S. NOL's would be fully utilized before they expired. These U.S. NOL's were fully utilized to offset U.S. taxable income in 2005.

The Company has Canadian non-capital tax loss carryforwards of approximately $4.2 million and $5.6 million as of December 31, 2006 and December 31, 2005, respectively. The benefit of the Canadian loss carryforwards can only be utilized to the extent the Company generates future taxable income in Canada. If not utilized, the Canadian loss carryforward will expire between 2007 and 2016.

The undistributed earnings of the Company's U.S. subsidiaries are considered to be indefinitely invested outside of Canada. Accordingly, no provision for Canadian income taxes and/or withholding taxes has been provided thereon.

Since the Company currently has no income producing operations in Canada, management estimates that it is more likely than not that the Canadian loss carryforwards will not be utilized. A valuation allowance has been recorded at December 31, 2006 and December 31, 2005 attributable to this deferred tax asset.

The Company periodically uses derivative instruments designated as cash flow hedges as a method of managing its exposure to commodity price fluctuations. To the extent these hedges are effective, changes in the fair value of these derivative instruments are recorded in Other Comprehensive Income, net of income tax. As of December 31, 2006 and December 31, 2005, the Company had no open derivative contracts; and, therefore, no recorded tax benefit attributable to unrecognized loss on derivative instruments. A tax benefit attributable to unrecognized loss on derivative instruments of $1,440,236 was allocated directly to Other Comprehensive Income as of December 31, 2004.

10. EMPLOYEE BENEFITS:

The Company sponsors a qualified, tax-deferred savings plan in accordance with provisions of Section 401(k) of the Internal Revenue Code for its employees. Employees may defer up to 15% of their compensation, subject to certain limitations. The Company matches the employee contributions up to 5% of employee compensation along with a profit sharing contribution of 8%. The plan operates on a calendar year basis and began in February 1998. The expense associated with the Company's contribution was $709,570, $507,306 and $396,684 for the years ended December 31, 2006, 2005 and 2004, respectively.

ULTRA PETROLEUM CORP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

11. SEGMENT INFORMATION:

The Company has two reportable operating segments, one domestic and one foreign, which are in the business of natural gas and crude oil exploration and production. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. The Company evaluates performance based on profit or loss from oil and natural gas operations before price-risk management and other, general and administrative expenses and interest expense. The Company's reportable operating segments are managed separately based on their geographic locations. Financial information by operating segment is presented below:

	United States	China	Total
Year-ended December 31, 2006			
Oil and gas sales	$ 508,659,524	$ 84,008,059	$ 592,667,583
Costs and Expenses:			
Depletion, depreciation and amortization	79,676,165	13,822,391	93,498,556
Lease operating expenses	15,067,413	8,922,400	23,989,813
Production taxes	57,899,339	8,398,473	66,297,812
Gathering	19,721,269	—	19,721,269
Operating income	$ 336,295,338	$ 52,864,795	$ 389,160,133
General and administrative			14,935,103
Other expense, net			1,966,125
Income before income taxes			$ 372,258,905
Capital expenditures	$ 481,390,936	$ 22,490,965	$ 503,881,901
Net oil and gas properties	$ 1,006,997,502	$ 112,370,594	$ 1,119,368,096

	United States	China	Total
Year-ended December 31, 2005			
Oil and gas sales	$ 448,730,965	$ 67,762,036	$ 516,493,001
Costs and Expenses:			
Depletion, depreciation and amortization	48,455,070	9,647,801	58,102,871
Lease operating expenses	9,047,390	7,352,000	16,399,390
Production taxes	52,689,060	3,388,089	56,077,149
Gathering	17,125,147	—	17,125,147
Operating income	$ 321,414,298	$ 47,374,146	$ 368,788,444
General and administrative			14,342,178
Other expense, net			2,673,934
Income before income taxes			$ 351,772,332
Capital expenditures	$ 263,486,693	$ 19,181,362	$ 282,668,055
Net oil and gas properties	$ 599,900,713	$ 102,762,542	$ 702,663,255

ULTRA PETROLEUM CORP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	United States	China	Total
Year-ended December 31, 2004			
Oil and gas sales	$ 238,866,913	$ 20,179,534	$ 259,046,447
Costs and Expenses:			
Depletion, depreciation and amortization	27,346,061	2,903,000	30,249,061
Lease operating expenses	6,286,715	2,286,000	8,572,715
Production taxes	28,151,661	1,009,098	29,160,759
Gathering	13,135,809	—	13,135,809
Operating income	$ 163,946,667	$ 13,981,436	$ 177,928,103
General and administrative			7,075,720
Other expense, net			3,692,310
Income before income taxes			$ 167,160,073
Capital expenditures	$ 179,592,969	$ 16,005,515	$ 195,598,484
Net oil and gas properties	$ 381,408,507	$ 93,225,879	$ 474,634,386

12. COMMITMENTS AND CONTINGENCIES:

On October 16, 2003 the operator of the Company's properties in China, Kerr-McGee, signed a 15 year contract, which provides for up to an additional 10 years, to lease a floating production storage offloading unit ("FPSO"). The Company ratified the contract for its net share which is 8.91%. The FPSO service agreement calls for a day rate lease payment and a sliding scale per barrel processing fee that decreases based on cumulative barrels processed. The lease contains a cancellation fee based on a sliding time-scale (cancellation fee decreases with time), which as of December 31, 2006 was $2.7 million, net to the Company's interest. The Company considers it very unlikely that a lease cancellation situation will occur. Due to the terms of the lease, the Company cannot estimate with any degree of accuracy the costs it may incur during the life of the lease. The Company's net share for the costs of the FPSO in 2006 was approximately $3.2 million.

In May 2003, the Company amended its prior office lease in Englewood, Colorado, which it has committed to through June 2008. The Company's total remaining commitment of this lease is $504,769 at December 31, 2006 ($333,359 in 2007 and $171,410 in 2008). In December 2003, the Company signed a lease for office space in Houston, Texas, which it has committed to through April 2007 for a total remaining commitment at December 31, 2006 of $33,948. At December 31, 2006, the remaining commitment on the Company's Pinedale office is $97,440 ($41,040 in 2007, $33,840 in 2008 and $22,560 in 2009). The total remaining commitment for all offices is $636,157.

As of December 31, 2006, the Company had committed to drilling obligations with certain rig contractors totaling $136,990,625 ($74,848,535 due in 2007 and the remaining $62,142,090 due in one to three years). The commitments expire in 2009 and were entered into to fulfill the Company's 2006-2009 drilling program initiatives in Wyoming.

During 2006, the Company took a major step toward assuring that the pipeline infrastructure to move its natural gas supplies away from southwest Wyoming will be expanded to provide sufficient capacity to transport its natural gas production and to provide for reasonable basis differentials for its natural gas in the future. The Company agreed to become an anchor shipper on the proposed Rockies Express Pipeline project, sponsored by subsidiaries of Kinder Morgan, Conoco Phillips, and Sempra Energy. The Rockies Express Pipeline, if built as proposed, would be the largest natural gas transmission pipeline project of its type built in the United States in more than 20 years, beginning at the Opal Processing Plant in southwest Wyoming and traversing Wyoming and several other states to an ultimate terminus in eastern Ohio. This pipeline is projected to cover more than 1,800 miles and is contemplated to be a large-diameter (42”), high-pressure natural gas pipeline. The Rockies Express Pipeline, if built, will be an interstate pipeline and would therefore be subject to the jurisdiction of the United States Federal Energy Regulatory Commission (“FERC”).

On December 19, 2005, the Company entered into two Precedent Agreements (“Precedent Agreements”) with Rockies Express Pipeline, LLC (“REX”) and Entrega Gas Pipeline, LLC. The Precedent Agreements govern the parties through the design, regulatory process and construction of the pipeline facilities and, subject to certain conditions precedent, the Company will take firm transportation service, if and when the pipeline facilities are constructed. Commencing upon completion of the pipeline facilities, the Company’s commitment involves capacity of 200,000 MMBtu per day of natural gas for a term of 10 years, and the Company will be obligated to pay to REX certain demand charges related to its rights to hold this firm transportation capacity as an anchor shipper. Based on current assumptions, current projections regarding the cost of the expansion and the participation of other shippers in the expansion (noting specifically that these assumptions are likely to change materially), the Company currently projects that annual demand charges due may be approximately $70.0 million per year for the term of the contract, exclusive of fuel and surcharges. The Company’s Board of Directors approved the Precedent Agreements on February 6, 2006 and Kinder Morgan, as the managing member of REX advised the Company of their final approval of the Precedent Agreements, and their intent to proceed with the construction of the Rockies Express Pipeline on February 28, 2006.

The Company is currently involved in various routine disputes and allegations incidental to its business operations. While it is not possible to determine the ultimate disposition of these matters, management, after consultation with legal counsel, is of the opinion that the final resolution of all such currently pending or threatened litigation is not likely to have a material adverse effect on the consolidated financial position, results of operations or cash flows of the Company.

13. FAIR VALUE OF FINANCIAL INSTRUMENTS:

For certain of the Company’s financial instruments, including accounts receivable, notes receivable, accounts payable and accrued liabilities, the carrying amounts approximate fair value due to the immediate or short-term maturity of these financial instruments. The Company’s long term debt is comprised of senior bank debt which bears interest at floating rates. Accordingly, the carrying value of the Company’s senior bank debt approximated fair value at December 31, 2006.

14. SIGNIFICANT CUSTOMERS:

The Company’s revenues are derived principally from uncollateralized sales to customers in the natural gas and oil industry. The concentration of credit risk in a single industry affects the Company’s overall exposure to credit risk because customers may be similarly affected by changes in economic and other conditions. In 2006, the Company had one significant customer for its CFD Chinese crude oil — CNOOC, and three significant customers for its natural gas production — Southern California Gas Company, J. Aron (Goldman Sachs), and Sempra Energy Trading. A significant customer is defined as one that individually accounts for 10% or more of the Company’s total natural gas or oil sales during 2006.

ULTRA PETROLEUM CORP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

15. SUMMARIZED QUARTERLY FINANCIAL INFORMATION (UNAUDITED):

	Revenues	Expenses	Income Before Income Tax Provision	Income Tax Provision	Net Income	Basic Earnings per Share	Diluted Earnings per Share
	(In thousands, except for per share data)						
2006							
First Quarter	$151,250	$ 47,284	$ 103,966	$ 36,492	$ 67,474	$ 0.43	$ 0.41
Second Quarter	$129,892	$ 45,959	$ 83,933	$ 33,258	$ 50,675	$ 0.33	$ 0.31
Third Quarter	$145,366	$ 56,561	$ 88,805	$ 36,330	$ 52,475	$ 0.34	$ 0.33
Fourth Quarter	$166,160	$ 70,605	$ 95,555	$ 34,983	$ 60,571	$ 0.40	$ 0.38
	$592,668	$220,409	$ 372,259	$141,063	$231,195		
2005							
First Quarter	$ 89,364	$ 31,857	$ 57,507	$ 20,185	$ 37,322	$ 0.25	$ 0.23
Second Quarter	$110,635	$ 36,848	$ 73,787	$ 25,899	$ 47,888	$ 0.31	$ 0.30
Third Quarter	$134,378	$ 40,618	$ 93,760	$ 32,910	$ 60,850	$ 0.40	$ 0.38
Fourth Quarter	$182,116	$ 55,398	$ 126,718	$ 44,478	$ 82,240	$ 0.53	$ 0.50
	$516,493	$164,721	$ 351,772	$123,472	$228,300		

16. DISCLOSURE ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED):

The following information about the Company’s oil and natural gas producing activities is presented in accordance with Financial Accounting Standards Board Statement No. 69, Disclosure About Oil and Gas Producing Activities:

A. *OIL AND GAS RESERVES:*

The determination of oil and natural gas reserves is complex and highly interpretive. Assumptions used to estimate reserve information may significantly increase or decrease such reserves in future periods. The estimates of reserves are subject to continuing changes and, therefore, an accurate determination of reserves may not be possible for many years because of the time needed for development, drilling, testing, and studies of reservoirs. The following unaudited tables as of December 31, 2006, 2005 and 2004 are based upon estimates prepared by Netherland, Sewell & Associates, Inc. and Ryder Scott Company. The estimates for properties in the United States were prepared by Netherland, Sewell & Associates, Inc. in reports dated January 30, 2007, January 27, 2006 and January 24, 2005, respectively. The estimates for properties in China were prepared by Ryder Scott Company in reports dated January 30, 2007, January 31, 2006, and February 11, 2005. These are estimated quantities of proved oil and natural gas reserves for the Company and the changes in total proved reserves as of December 31, 2006, 2005 and 2004. All such reserves are located in the Green River Basin, Wyoming, Pennsylvania and Bohai Bay, China.

ULTRA PETROLEUM CORP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

B. ***ANALYSES OF CHANGES IN PROVEN RESERVES:***

	United States		China		Total	
	Oil (Bbls)	Natural Gas (Mcf)	Oil (Bbls)	Natural Gas (Mcf)	Oil (Bbls)	Natural Gas (Mcf)
Reserves, December 31, 2003	8,342,500	1,023,367,300	—	—	8,342,500	1,023,367,300
Extensions, discoveries and additions	4,520,000	562,548,000	8,180,900	—	12,700,900	562,548,000
Production	(349,700)	(43,667,400)	(624,560)	—	(943,000)	(43,667,400)
Revisions	(1,123,700)(1)	(128,247,300)(2)	31,228	—	(1,123,700)	(128,247,300)
Reserves, December 31, 2004	11,389,100	1,414,000,600	7,587,600	—	18,976,700	1,414,000,600
Extensions, discoveries and additions	5,516,300	680,671,500	370,600	—	5,886,900	680,671,500
Production	(464,300)	(61,722,300)	(1,556,300)	—	(2,020,600)	(61,722,300)
Revisions	(1,236,400)(3)	(132,727,000)(4)	(1,341,000)	—	(2,577,400)	(132,727,000)
Reserves, December 31, 2005	15,204,700	1,900,222,800	5,060,900	—	20,265,600	1,900,222,800
Extensions, discoveries and additions	3,962,000	505,773,000	—	—	3,962,000	505,773,000
Production	(594,100)	(78,395,500)	(1,603,400)	—	(2,197,500)	(78,395,500)
Revisions	(730,000)(5)	(69,499,600)(6)	529,200	—	(200,800)	(69,499,600)
Reserves, December 31, 2006	17,842,600	2,258,100,700	3,986,700	—	21,829,300	2,258,100,700
Proved developed reserves:						
December 31, 2003	3,028,000	359,072,000	—	—	—	359,072,000
December 31, 2004	4,195,000	514,686,000	4,356,000	—	8,551,000	514,686,000
December 31, 2005	5,087,000	635,591,000	2,484,000	—	7,571,000	635,591,000
December 31, 2006	6,522,000	842,969,000	2,686,000	—	9,208,000	842,969,000

(1) Revision amount of 936,500 attributable to 40 wells dropped from PUD category replaced by more attractive wells.

(2) Revision amount of 117,064,000 associated with above 40 mentioned wells.

(3) Revision amount of 412,500 attributable to 26 wells dropped from PUD category replaced by more attractive wells.

(4) Revision amount of 51,560,000 associated with above mentioned 26 wells.

(5) Revision amount of 460,000 attributable to 28 wells dropped from PUD category replaced by more attractive wells.

(6) Revision amount of 57,489,000 associated with above mentioned 28 wells.

ULTRA PETROLEUM CORP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

C. ***STANDARDIZED MEASURE (US$000):***

The following table sets forth a standardized measure of the estimated discounted future net cash flows attributable to the Company's proved natural gas reserves. Natural gas prices have fluctuated widely in recent years. The calculated weighted average sales prices utilized for the purposes of estimating the Company's proved reserves and future net revenues were $4.50, $8.00, and $5.46 per Mcf of natural gas at December 31, 2006, 2005 and 2004, respectively. The calculated weighted average oil price at December 31, 2006, 2005, and 2004 for Wyoming was $59.95, $60.81 and $42.80, respectively and $5.51 per Mcf at December 31, 2006 in Pennsylvania. The calculated weighted average crude oil price at December 31, 2006, 2005 and 2004 for China was a Duri price of $46.57, $48.74 and $29.46, respectively. The future production and development costs represent the estimated future expenditures to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. Future income tax expense was computed by applying statutory income tax rates to the difference between pretax net cash flows relating to the Company's proved reserves and the tax basis of proved properties and available operating loss carryovers.

	United States	China	Total
As of December 31, 2004			
Future cash inflows	$ 8,213,061	$223,531	$ 8,436,592
Future production costs	(1,699,891)	(67,387)	(1,767,278)
Future development costs	(623,539)	(18,382)	(641,921)
Future income taxes	(1,988,387)	(21,436)	(2,009,823)
Future net cash flows	3,901,244	116,326	4,017,570
Discounted at 10%	(2,285,779)	(62,455)	(2,348,234)
Standardized measure of discounted future net cash flows	$ 1,615,465	$ 53,871	$ 1,669,336
As of December 31, 2005			
Future cash inflows	$ 16,124,248	$246,666	$ 16,370,914
Future production costs	(2,943,364)	(72,920)	(3,016,284)
Future development costs	(1,113,618)	(6,815)	(1,120,433)
Future income taxes	(4,110,554)	(30,235)	(4,140,789)
Future net cash flows	7,956,712	136,696	8,093,408
Discounted at 10%	(4,454,628)	(62,286)	(4,516,914)
Standardized measure of discounted future net cash flows	$ 3,502,084	$ 74,410	$ 3,576,494
As of December 31, 2006			
Future cash inflows	$ 11,239,526	$185,659	$ 11,425,185
Future production costs	(2,974,427)	(67,750)	(3,042,177)
Future development costs	(1,674,893)	(5,915)	(1,680,808)
Future income taxes	(2,217,709)	(6,710)	(2,224,419)
Future net cash flows	4,372,497	105,284	4,477,781
Discounted at 10%	(2,587,417)	(18,811)	(2,606,228)
Standardized measure of discounted future net cash flows	$ 1,785,080	$ 86,473	$ 1,871,553

The estimate of future income taxes is based on the future net cash flows from proved reserves adjusted for the tax basis of the oil and gas properties but without consideration of general and administrative and interest expenses.

D. *SUMMARY OF CHANGES IN THE STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS (US$000):*

	December 31, 2006	December 31, 2005	December 31, 2004
Standardized measure, beginning	$ 3,576,494	$ 1,669,336	$ 1,135,513
Net revisions	(185,419)	(436,425)	(245,950)
Extensions, discoveries and other changes	755,149	2,306,982	1,062,236
Changes in future development costs	(193,004)	(130,727)	(123,051)
Sales of oil and gas, net of production costs	(482,659)	(426,891)	(216,670)
Net change in prices and production costs	(2,915,081)	1,992,707	2,645
Development costs incurred during the period that reduce future development costs	243,933	172,962	96,220
Accretion of discount	544,558	254,236	178,431
Net changes in production rates and other	(395,071)	—	—
Net change in income taxes	922,653	(1,825,686)	(220,038)
Standardized measure, ending	$ 1,871,553	$ 3,576,494	$ 1,669,336

There are numerous uncertainties inherent in estimating quantities of proved reserves and projected future rates of production and timing of development expenditures, including many factors beyond the control of the Company. The reserve data and standardized measures set forth herein represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers often vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of such estimates. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. Further, the estimated future net revenues from proved reserves and the present value thereof are based upon certain assumptions, including geologic success, prices, future production levels and costs that may not prove correct over time. Predictions of future production levels are subject to great uncertainty, and the meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they are based. Historically, oil and natural gas prices have fluctuated widely.

E. *COSTS INCURRED IN OIL AND GAS EXPLORATION AND DEVELOPMENT ACTIVITIES (US$000):*

UNITED STATES

	Years Ended		
	December 31, 2006	December 31, 2005	December 31, 2004
Acquisition costs — unproved properties	$ 11,351	$ 775	$ 1,268
Exploration	152,922	56,894	97,068
Development	317,118	208,173	82,646
Total	$ 481,391	$ 265,842	$ 180,982

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CHINA

	Years Ended December 31, 2006	December 31, 2005	December 31, 2004
Acquisition costs — unproved properties	$ 7,152	$ 2,876	$ 2,351
Exploration	—	—	—
Development	15,339	16,465	12,657
Total	$ 22,491	$ 19,341	$ 15,008

TOTAL

	Years Ended December 31, 2006	December 31, 2005	December 31, 2004
Acquisition costs — unproved properties	$ 18,503	$ 3,651	$ 3,619
Exploration	152,922	56,894	97,068
Development	332,457	224,638	95,303
Total	$ 503,882	$ 285,183	$ 195,990

F. *RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES (US$000):*

UNITED STATES

	Years Ended December 31, 2006	December 31, 2005	December 31, 2004
Oil and gas revenue	$ 508,660	$ 448,731	$ 238,867
Production expenses and taxes	(92,688)	(78,861)	(47,574)
Depletion and depreciation	(79,676)	(48,456)	(27,346)
Income taxes	(111,722)	(107,916)	(53,406)
Total	$ 224,574	$ 213,498	$ 110,541

CHINA

	Years Ended December 31, 2006	December 31, 2005	December 31, 2004
Oil and gas revenue	$ 84,008	$ 67,762	$ 20,180
Production expenses and taxes	(17,321)	(10,740)	(3,295)
Depletion and depreciation	(13,822)	(9,648)	(2,903)
Income taxes	(18,941)	(15,556)	(4,604)
Total	$ 33,924	$ 31,818	$ 9,378

ULTRA PETROLEUM CORP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

TOTAL

	Years Ended December 31, 2006	December 31, 2005	December 31, 2004
Oil and gas revenue	$ 592,668	$ 516,493	$ 259,047
Production expenses and taxes	(110,009)	(89,601)	(50,869)
Depletion and depreciation	(93,498)	(58,104)	(30,249)
Income taxes	(130,663)	(123,472)	(58,010)
Total	$ 258,498	$ 245,316	$ 119,919

G. *CAPITALIZED COSTS RELATING TO OIL AND GAS PRODUCING ACTIVITIES:*

	December 31, 2006	December 31, 2005
Developed Properties:		
Acquisition, equipment, exploration, drilling and environmental costs — Domestic	$ 1,174,683,088	$ 700,425,880
Acquisition, equipment, exploration, drilling and environmental costs — China	96,873,985	43,890,413
Less accumulated depletion, depreciation and amortization — Domestic	(196,683,521)	(118,172,467)
Less accumulated depletion, depreciation and amortization — China	(26,565,809)	(13,183,036)
	1,048,307,743	612,960,790
Unproven Properties:		
Acquisition and exploration costs — Domestic	28,997,935	17,647,300
Acquisition and exploration costs — China	42,062,418	72,055,165
	$ 1,119,368,096	$ 702,663,255

Item 9. ***Change in and Disagreements with Accountants on Accounting and Financial Disclosures.***

None.

Item 9A. ***Controls and Procedures.***

Management's Report on Assessment of Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company as such term is defined in Rules 13a-15(f) and 15d-15(f) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act"). In order to evaluate the effectiveness of internal control over financial reporting, as required by Section 404 of the Sarbanes-Oxley Act, management has conducted an assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, using the criteria in Internal Control — Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). 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.

Based on the results of this assessment, management (including our chief executive officer and our chief financial officer) has concluded that, as of December 31, 2006, our internal control over financial reporting was effective. Management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2006 has been audited by Ernst & Young, an independent registered public accounting firm, as stated in their report which appears herein.

Remediation of Material Weakness

In connection with the preparation of the Company's Annual Report on Form 10-K for the year ended December 31, 2005 ("2005 10-K"), an evaluation was performed under the supervision and with the participation of the Company's management, including the chief executive officer and the chief financial officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures. The Company concluded that control deficiencies in its internal control over financial reporting as of December 31, 2005, constituted material weaknesses within the meaning of the Public Company Accounting Oversight Board's Auditing Standard No. 2 as follows:

- The Company did not maintain effective company level controls. Specifically, (i) certain of its accounting personnel in key roles did not possess an appropriate level of technical expertise, and (ii) the Company's monitoring of the internal audit function was not sufficient to provide management a basis to assess the quality of the Company's internal control performance over time. These deficiencies resulted in more than a remote likelihood that a material misstatement of the Company's annual or interim financial statements would not be prevented or detected.
- The Company did not have adequate policies and procedures regarding supervisory review of account reconciliations and account and transaction analyses. This deficiency resulted in material errors (as reported in the 2005 10-K) which were corrected prior to the issuance of the Company's 2005 consolidated financial statements.
- The Company did not have adequate policies and procedures to ensure that accurate and reliable interim and annual consolidated financial statements were prepared and reviewed on a timely basis. Specifically, the Company did not have sufficient personnel with the skills and experience in the application of U.S. generally accepted accounting principles and policies and procedures regarding the preparation and management review of footnote disclosures accompanying the Company's financial statements. As a result of these deficiencies, material errors were identified in the footnotes to the Company's preliminary 2005 consolidated financial statements. These errors were corrected by management prior to the issuance of the Company's 2005 consolidated financial statements.

For additional information relating to the control deficiencies that resulted in the material weakness described above, please see the discussion under “Item 9A. Controls and Procedures — Management’s Report on Internal Control Over Financial Reporting” contained in the 2005 10-K and “Item 4. Controls and Procedures” contained in our reports on Form 10-Q for the periods ended March 30, June 30, and September 30, 2006, respectively.

During 2006, we implemented a number of remediation measures to address the material weakness described above. As described in our 2005 10-K, the Company’s remediation plans included:

- increasing training for the Company’s current accounting personnel, hiring additional accounting personnel and engaging outside consultants with technical accounting expertise, as needed, and reorganizing the accounting department to ensure that accounting personnel have adequate experience, skills and knowledge relating to the accounting and internal audit functions assigned to them; and
- establishing additional and refining current policies and procedures to more effectively reconcile the Company’s accounting entries along with better documentation procedures to meet the standards established by COSO.

In order to remediate the material weaknesses described in the 2005 10-K, during 2006 the Company:

- implemented an internal review and assessment process regarding its financial reporting and internal audit functions;
- engaged Protiviti to (1) review and assess current Sarbanes-Oxley processes and control documentation and compliance plans, (2) recommend remediation and project plans for 2006, and (3) assist management with Sarbanes-Oxley compliance requirements during 2006;
- engaged Grant Thornton LLP to assist in identifying and recommending any necessary organization and procedural changes for improving the Company’s controls for the purposes of complying with Sarbanes-Oxley;
- increased training and hired additional accounting personnel;
- acted on the recommendations of Protiviti and Grant Thornton LLP;
- effected a reorganization and alignment of the Company’s financial reporting and internal audit functions;
- established additional policies and procedures for monitoring and reconciling the Company’s accounting entries; and
- established better documentation procedures to more fully comply with the standards established by COSO.

Changes in Internal Control Over Financial Reporting

While the planned remediation steps were designed and in place by the end of the 3rd quarter of 2006, management continued to evaluate the operating effectiveness through the end of fiscal year 2006 when it was concluded that the Company’s internal control over financial reporting was sufficiently mature to support an assessment that the controls were effective. There were no changes in our internal control over financial reporting during the quarter ended December 31, 2006 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Evaluation of Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our chief executive officer and our chief financial officer, we evaluated the effectiveness of our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) and Rule 15d-15(e) promulgated under the Exchange Act. Based on that evaluation, our chief executive officer and our chief financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2006. The evaluation considered the procedures designed to ensure that information required to be disclosed by us in the reports filed or submitted by us under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms and communicated to our management as appropriate to allow timely decisions regarding required disclosure.

Item 9B. ***Other Information.***

None.

Part III

Item 10. ***Directors, Executive Officers and Corporate Governance***

The information required by this item is incorporated herein by reference to the Company's definitive proxy statement, which will be filed not later than 120 days after December 31, 2006.

The Company has adopted a code of ethics that applies to the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer. The full text of such code of ethics is posted on the Company's website at www.ultrapetroleum.com, and is available free of charge in print to any shareholder who requests it. Requests for copies should be addressed to the Secretary at 363 North Sam Houston Parkway East, Suite 1200, Houston, Texas 77060.

Item 11. ***Executive Compensation.***

The information required by this item is incorporated herein by reference to the Company's definitive proxy statement, which will be filed not later than 120 days after December 31, 2006.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.***

The information required by Item 403 of Regulation S-K will be included in the Company's definitive proxy statement, which will be filed not later than 120 days after December 31, 2006 and is incorporated herein by reference.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence.***

The information required by this item is incorporated herein by reference to the Company's definitive proxy statement, which will be filed not later than 120 days after December 31, 2006.

Item 14. ***Principal Accounting Fees and Services.***

The information required by this item is incorporated herein by reference to the Company's definitive proxy statement, which will be filed not later than 120 days after December 31, 2006.

Part IV

Item 15. ***Exhibits, Financial Statement Schedules.***

The following documents are filed as part of this report:

1. *Financial Statements:* See Item 8.

2. *Financial Statement Schedules:* None.

3. *Exhibits.* The following Exhibits are filed herewith pursuant to Rule 601 of the Regulation S-K or are incorporated by reference to previous filings.

Exhibit Number	Description
3.1	Articles of Incorporation of Ultra Petroleum Corp. (incorporated by reference to Exhibit 3.1 of the Company's Quarterly Report on Form 10-Q for the period ended June 30, 2001).
3.2	By-Laws of Ultra Petroleum Corp. (incorporated by reference to Exhibit 3.2 of the Company's Quarterly Report on Form 10-Q for the period ended June 30, 2001).

Exhibit Number	Description
4.1	Specimen Common Share Certificate (incorporated by reference to Exhibit 4.1 of the Company's Quarterly Report on Form 10-Q for the period ended June 30, 2001).
10.1	Fourth Amendment to Second Amended and Restated Credit Agreement, dated as of November 14, 2005 and effective as of November 18, 2005, by and among Ultra Resources, Inc., JPMorgan Chase Bank N.A., Union Bank of California N.A., Hibernia National Bank, Guaranty Bank FSB, Compass Bank, Bank of Scotland and Bank of America, N.A. (incorporated by reference to Exhibit 10.1 of the Company's Report on Form 8-K filed on November 23, 2005).
10.2	Third Amendment to Second Amended and Restated Credit Agreement dated May 5, 2005 among Ultra Resources, Inc., JPMorgan Chase Bank N.A., Union Bank of California N.A., Hibernia National Bank, Guaranty Bank FSB, Compass Bank, Bank of Scotland and Bank of America, N.A. (incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the period ended June 30, 2005).
10.3	Second Amendment to Second Amended and Restated Credit Agreement dated November 1, 2004 among Ultra Resources, Inc., Bank One, NA, Union Bank of California, N.A., Hibernia National Bank, Guaranty Bank, FSB, Compass Bank, Bank of Scotland and Fleet National Bank. (incorporated by reference to Exhibit 10.1 of the Company's Report on Form 10-K for the year ended December 31, 2004).
10.4	First Amendment to Second Amended and Restated Credit Agreement dated August 10, 2004 among Ultra Resources, Inc., Bank One, NA, Union Bank of California, N.A., Hibernia National Bank, Guaranty Bank, FSB, Compass Bank, Bank of Scotland and Fleet National Bank. (incorporated by reference to Exhibit 10.2 of the Company's Report on Form 10-K for the year ended December 31, 2004).
10.5	Second Amended and Restated Credit Agreement dated June 9, 2004 among Ultra Resources, Inc., Bank One, NA, Union Bank of California, N.A., Hibernia National Bank, Guaranty Bank, FSB, Compass Bank, Bank of Scotland and Fleet National Bank (incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the period ended June 30, 2004).
10.6	Precedent Agreement between Rockies Express Pipeline LLC and Ultra Resources, Inc. dated December 19, 2005 (incorporated by reference to Exhibit 10.1 of the Company's Report of Form 8-K filed on February 9, 2006).
10.7	Precedent Agreement between Rockies Express Pipeline LLC, Entrega Gas Pipeline LLC and Ultra Resources, Inc. dated December 19, 2005 (incorporated by reference to Exhibit 10.2 of the Company's Report on Form 8-K filed on February 9, 2006).
10.8	Ultra Petroleum Corp. 2005 Stock Incentive Plan (incorporated by reference to Exhibit 99.1 of the Company's Registration Statement on Form S-8 (Reg. No. 333-132443), filed with the SEC on March 15, 2006).
10.9	Ultra Petroleum Corp. 2000 Stock Incentive Plan (incorporated by reference to Exhibit 99.1 of the Company's Registration Statement on Form S-8 (Reg. No. 333-13278), filed with the SEC on March 15, 2001).
10.10	Ultra Petroleum Corp. 1998 Stock Option Plan (incorporated by reference to Exhibit 99.1 of the Company's Registration Statement on Form S-8 (Reg. No. 333-13342) filed with the SEC on April 2, 2001).
10.11	Employment Agreement between Ultra Petroleum Corp. and Michael D. Watford dated February 1, 2004 (incorporated by reference from Exhibit 10.11 of the Company's Annual Report on Form 10-K for the year ended December 31, 2005).
14.1	Code of Ethics for Chief Executive Officer and Senior Financial Officers of Ultra Petroleum Corp. (incorporated by reference to Exhibit 3.3 of the Company's Annual Report on Form 10-K for the year ended December 31, 2003).
*21.1	Subsidiaries of the Company.
*23.1	Consent of Netherland, Sewell & Associates, Inc.
*23.2	Consent of Ryder Scott Company.
*23.3	Consent of Ernst & Young LLP.
*23.4	Consent of KPMG LLP.

Exhibit Number	Description
*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.
*32.1	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith

Table of Contents

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.

ULTRA PETROLEUM CORP.

By: /s/ Michael D. Watford
Name: Michael D. Watford
Title: Chairman of the Board,
Chief Executive Officer, and President

Date: February 26, 2007

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

Signature	Title	Date
/s/ Michael D. Watford Michael D. Watford	Chairman of the Board, Chief Executive Officer, and President (principal executive officer)	February 26, 2007
/s/ Marshall D. Smith Marshall D. Smith	Chief Financial Officer (principal financial officer)	February 26, 2007
/s/ Garland R. Shaw Garland R. Shaw	Corporate Controller (principal accounting officer)	February 26, 2007
/s/ W. Charles Helton W. Charles Helton	Director	February 26, 2007
/s/ Stephen J. McDaniel Stephen J. McDaniel	Director	February 26, 2007
/s/ Robert E. Rigney Robert E. Rigney	Director	February 26, 2007
/s/ James C. Roe James C. Roe	Director	February 26, 2007

EXHIBIT INDEX

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*23.2	Consent of Ryder Scott Company.
*23.3	Consent of Ernst & Young LLP.
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*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.
*32.1	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith

Exhibit 21.1

LIST OF SUBSIDIARIES OF ULTRA PETROLEUM CORP.

Entity	Jurisdiction of Organization
Keystone Gas Gathering, LLC	Delaware
Sino-American Energy Corporation	Nevada
Ultra Resources, Inc.	Wyoming
UP Energy Corporation	Nevada

EXHIBIT 23.1

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

Netherland, Sewell & Associates, Inc. has issued a report, as of December 31, 2006, of the "Estimate of Reserves and Future Revenue to the Ultra Petroleum Corporation Interest in certain oil and gas properties prepared in accordance with Securities and Exchange Commission guidelines" for Ultra Petroleum Corp. Netherland, Sewell & Associates, Inc. consents to the reference in Form 10-K to Netherland, Sewell & Associates, Inc.'s reserve report dated January 30, 2007, and to the incorporation by reference of our Firm's name and report into Ultra's previously filed Registration Statements on Form S-8 (File Nos. 333-132443; 333-13342; 333-13278) and Form S-3 (File No. 333-89522).

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ Frederic D. Sewell
Frederic D. Sewell
Chairman and Chief Executive Officer

Dallas, Texas
February 20, 2007

EXHIBIT 23.2

CONSENT OF INDEPENDENT RESERVE ENGINEERS

Ryder Scott Company has issued a report as of December 31, 2006 of the "Estimated Future Reserves and Income Attributable to Certain Leasehold interests (SEC Case)" for Ultra Petroleum Corp. Ryder Scott Company consents to the reference in Form 10-K to Ryder Scott Company reserve report dated January 30, 2007 referenced in "*Item 2. Properties — Oil and Gas Reserves*" exclusive of future income taxes and to the incorporation by reference of our Firm's name and report into Ultra's previously filed Registration Statements on Form S-8 (File Nos. 333-132443; 333-13342; 333-13278) and Form S-3 (File No. 333-89522).

/s/ RYDER SCOTT COMPANY, L.P.
RYDER SCOTT COMPANY, L.P.

Houston, Texas
February 20, 2007

Exhibit 23.3

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statement (Form S-8 No. 333-132443) pertaining to the Ultra Petroleum Corp. 2005 Stock Incentive Plan, and

(2) Registration Statement (Form S-3 No. 333-89522) of Ultra Petroleum Corp.;

of our reports dated February 26, 2007, with respect to the consolidated financial statements of Ultra Petroleum Corp., Ultra Petroleum Corp. management's assessment of the effectiveness of internal control over financial reporting, and the effectiveness of internal control over financial reporting of Ultra Petroleum Corp., included in this Annual Report (Form 10-K) for the year ended December 31, 2006.

Houston, Texas
February 27, 2007

Exhibit 23.4

Consent of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Ultra Petroleum Corp.:

We consent to the incorporation by reference in the Registration Statements No. 333-89522 on Form S-3 and No. 333-132443 on Form S-8 of Ultra Petroleum Corp. of our report dated March 30, 2006 with respect to the consolidated balance sheet of Ultra Petroleum Corp. and subsidiaries as of December 31, 2005, and the related consolidated statements of operations and retained earnings, shareholders' equity, and cash flow for each of the years in the two-year period ended December 31, 2005, which report appears in the December 31, 2006 Annual Report on Form 10-K of Ultra Petroleum Corp.

KPMG LLP
Denver, Colorado
February 26, 2007

Exhibit 31.1

SECTION 302 CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
ULTRA PETROLEUM CORP.

I, Michael D. Watford, certify that:

1. I have reviewed this annual report on Form 10-K of Ultra Petroleum Corp.;
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(s) 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(s) 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 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 controls over financial reporting.

Date: February 26, 2007

By: /s/ Michael D. Watford
Michael D. Watford,
Chairman, President and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

SECTION 302 CERTIFICATION OF CHIEF FINANCIAL OFFICER
ULTRA PERTROLEUM CORP.

I, Marshall D. Smith, certify that:

1. I have reviewed this annual report on Form 10-K of Ultra Petroleum Corp.;

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(s) 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(s) 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 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 controls over financial reporting.

Date: February 26, 2007

By: /s/ Marshall D. Smith

Marshall D. Smith,
Chief Financial Officer
(Principal Financial Officer)

Exhibit 32.1

SECTION 906 CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
ULTRA PERTROLEUM CORP.

I, Michael D. Watford, President and Chief Executive Officer of Ultra Petroleum Corp. (the “Company”), certify that:

1. this annual report on Form 10-K for the year ended December 31, 2006, filed with the Securities and Exchange Commission on the date hereof (the “Report”), fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act pf 1934 (15 U.S.C. 78m or 78o(d)); and
2. the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: February 26, 2007

/s/ Michael D. Watford
Michael D. Watford,
Chairman, President and Chief Executive Officer

This certification is furnished as an exhibit to the Report, pursuant to Item 601(b)(32) of Regulation S-K and Section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code) and, accordingly, will not be deemed “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This certification will not be incorporated by reference into any filing under the Securities Act or Exchange Act of the Company, unless the Company specifically incorporates it by reference.

Exhibit 32.2

SECTION 906 CERTIFICATION OF CHIEF FINANCIAL OFFICER
ULTRA PETROLEUM CORP.

I, Marshall D. Smith, Chief Financial Officer of Ultra Petroleum Corp. (the “Company”), certify that:

1. this annual report on Form 10-K for the year ended December 31, 2006, filed with the Securities and Exchange Commission on the date hereof (the “Report”), fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

2. the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: February 26, 2007

/s/ Marshall D. Smith

Marshall D. Smith,
Chief Financial Officer

This certification is furnished as an exhibit to the Report, pursuant to Item 601(b)(32) of Regulation S-K and Section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code) and, accordingly, will not be deemed “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This certification will not be incorporated by reference into any filing under the Securities Act or Exchange Act of the Company, unless the Company specifically incorporates it by reference.