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, 2012

☐ **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 001-33614

ULTRA PETROLEUM CORP.

(Exact name of registrant as specified in its charter)

Yukon Territory, Canada	**N/A**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. employer identification number)*
400 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	New York 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 requirements for the past 90 days. YES ☑ NO ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). 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, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

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 $3,528,103,567 as of June 30, 2012 (based on the last reported sales price of $23.07 of such stock on the New York Stock Exchange on such date).

The number of common shares, without par value, of Ultra Petroleum Corp., outstanding as of February 15, 2013 was 152,929,907.

Documents incorporated by reference: The definitive Proxy Statement for the 2013 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2012, 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.
- ***Tcfe*** — One trillion 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.
- ***Condensate*** — An oil-like, liquid hydrocarbon which is produced in association with natural gas production that condenses from natural gas as it is produced and delivered into a separator or similar equipment prior to the delivery of such natural gas to the natural gas gathering pipeline system.
- ***MBbl*** — One thousand barrels of crude oil or other liquid hydrocarbons.
- ***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. This conversion ratio, which is typically used in the oil and gas industry, represents the approximate energy equivalent of a barrel of oil or condensate to an Mcf of natural gas. The sales price of one barrel of oil or condensate has been much higher than the sales price of six Mcf of natural gas over the last several years, so a six to one conversion ratio does not represent the economic equivalency of six Mcf of natural gas to one barrel of oil or condensate.
- ***MMBbl*** — One million barrels of crude 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 after 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 based on the average price during the 12-month period before the ending date of the period covered by the report determined as an un-weighted, arithmetic average of the first-day-of-the-month price for each month within such period, 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:

Economically producible — A resource that generates revenue that exceeds (or is reasonably expected to exceed) costs of the operation.

Estimated ultimate recovery ("EUR") — The sum of reserves remaining as of a given date and cumulative production as of that date.

Proved oil and gas reserves — Proved oil and natural gas reserves are those quantities of oil and gas, which, by analysis of available geoscience and engineering data, can be estimated with reasonable certainty to be economically producible — from a given date forward from known reservoirs and under existing economic conditions, operating methods, and government regulation — before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

The area of the reservoir considered as proved includes all of the following:

a. The area identified by drilling and limited fluid contacts, if any,

b. Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establish a lower contact with reasonable certainty.

Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves that can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when both of the following occur:

a. Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based.

b. The project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price is the average price during the 12-month period before the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved developed oil and gas reserves — Proved oil and gas reserves that can be expected to be recovered:

a. Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well.

b. Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Proved undeveloped oil and gas reserves — Proved oil and gas reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

Under no circumstances are estimates for proved undeveloped reserves attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Reasonable certainty — If deterministic methods are used, a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

Reliable technology — A grouping of one or more technologies (including computational methods) that has been field tested and demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

Resources — Quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

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

- ***Revenue interest*** — The amount of the interest owned in the proceeds derived from a producing well less all royalty interests.

- ***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.

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.

Other Terms

- ***All-in costs*** — For any period, means the sum of lease operating expenses, severance taxes, gathering costs, transportation charges, depletion, depreciation and amortization, interest expense and general and administrative expenses divided by production on an Mcfe basis during the period.
- ***Reserve replacement ratio*** — The sum of the estimated net proved reserves added through extensions, discoveries, revisions and additions (including purchases of reserves) for a specified period of time divided by production for that same period of time.
- ***Finding and development costs*** — The sum of property acquisition costs, exploration costs and development costs for a specified period of time, divided by the total of proved reserve extensions, discoveries, revisions and additions (including purchases) for that same period of time.

PART I

Item 1. *Business.*

General

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 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 located in the Green River Basin of southwest Wyoming and the north-central Pennsylvania area of the Appalachian Basin.

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 "SEC Filings" 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, 400 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 the Company. The SEC's website address is www.sec.gov.

Oil and Gas Properties Overview

Ultra's current operations in southwest Wyoming are focused on developing its long-life natural gas reserves in a tight gas sand trend located in the Green River Basin with targets in 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. As of December 31, 2012, Ultra owned interests in approximately 84,000 gross (49,000 net) acres in Wyoming covering approximately 190 square miles.

Ultra's current operations in north-central Pennsylvania are focused on assessing, exploring and developing its position in the Marcellus Shale and other horizons. At December 31, 2012, the Company owned interests in approximately 497,000 gross (261,000 net) acres in Pennsylvania.

In eastern Colorado, at December 31, 2012, the Company owned interests in approximately 154,000 gross (139,000 net) acres. The Company has no immediate plans for further exploration in this area.

Business Strategy

Ultra's mission is to profitably grow an upstream oil and gas company for the long-term benefit of its shareholders. Ultra's strategy includes building a robust portfolio of high return investment opportunities, maintaining a disciplined approach to capital investment, maximizing earnings and cash flows by controlling costs and maintaining financial flexibility. Consistent with our mission and this strategy, the Company significantly reduced its activity during 2012 as a result of the low prevailing natural gas prices during the year. The Company believes the low natural gas prices are unsustainable because capital investment in natural gas drilling has been reduced broadly across the industry and the Company believes natural gas supply will decline as a result. For additional information about steps the Company is taking to address low natural gas prices, see the "Marketing and Pricing" section of Item 1. Business.

High Return Portfolio. Ultra seeks to maintain a portfolio of properties that provide long-term, profitable growth through development in areas that support sustainable, lower-risk, repeatable, high return drilling projects. The Company continually evaluates opportunities for the acquisition, exploration and development of additional oil and natural gas properties that afford risk-adjusted returns in excess of or equal to its current set of investment alternatives.

Disciplined Capital Investment. Part of the Company's business strategy includes proactive and regular review of its portfolio of investment opportunities with a focus on investments that produce positive returns in order to optimize return to its shareholders. Accordingly, in response to the current low natural gas price environment, the Company reduced capital expenditures by reducing the number of drilling rigs operating in its Wyoming fields and is encouraging the parties operating projects on its behalf in Pennsylvania to reduce their activity as well. Reductions in the Company's activity resulted in reduced capital spending during the current year as compared to the prior year.

Low Cost Producer. Ultra strives to maintain one of the lowest cost structures in the industry in terms of both adding and producing oil and natural gas reserves. The Company continues to focus on improving its drilling and production results through the use of advanced technologies and detailed technical analysis of its properties. For the year ended 2012, the Company's all-in costs were $3.00 per Mcfe.

Financial Flexibility. Preserving financial flexibility and a strong balance sheet are also key components of Ultra's business strategy. At December 31, 2012, the Company had cash on hand of $12.9 million and outstanding debt was $1.8 billion. At December 31, 2012, the Company had $723.0 million of available borrowing capacity under its revolving credit facility. The Company's average debt maturity is approximately seven years and the Company's weighted average cost of debt is approximately 5.1%.

During December 2012, the Company sold a system of its liquids gathering pipelines and central gathering facilities and certain associated real property rights in the Pinedale Anticline in Wyoming. The net cash proceeds received for the assets were $203.0 million and $23.0 million in marketable securities which were sold during December 2012 for net cash proceeds of $21.2 million. The Company used the net proceeds of the sale to reduce its outstanding indebtedness under its revolving credit facility.

Exploration and Production

Green River Basin, Wyoming

During 2012, the Company participated in the drilling of 135 wells in Wyoming and continued to improve its drilling and completion efficiency on its operated wells as measured by spud to total depth. During 2012, the Company averaged 11.5 days to drill a well, as measured by spud to total depth. This compares to an average of 12 days to drill during 2011, a 4% reduction. Similarly, Ultra reached total depth in 10 days or less on 33% of all operated wells drilled in 2012 as compared to 12% of operated wells in 2011. Total days per well, measured by rig-release to rig-release, decreased 3% to 14.5 days in 2012 compared to 15 days during 2011.

During 2013, the Company plans to continue the ongoing development of its acreage position in the tight gas sand trend in the Green River Basin in southwest Wyoming. The Company expects that wells drilled during 2013 in the Pinedale field will target the sands of the upper Cretaceous Lance Pool.

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 refine areas of drilling focus, to identify areas for future extension of the Lance fairway and to identify deeper objectives which may warrant drilling.

Pennsylvania

Ultra continued the assessment of its Pennsylvania acreage during 2012. During the year, the Company participated in the drilling of 59 horizontal wells. At the end of 2012, approximately 71% of the Company's acreage holdings in Pennsylvania were covered by high quality 3D seismic data, which the Company uses to guide its investment decisions.

During 2013, the Company plans to continue its exploration and development activities in the Middle Devonian Marcellus Shale Play on its acreage in Pennsylvania. The Company also plans to continue evaluating the potential for the Upper Devonian Geneseo Shale Play across its Pennsylvania acreage position. Ultra's current activities are located in Potter, Tioga, Clinton, Centre and Lycoming counties. Activities include lease acquisition, 3-D seismic, drilling, completion, infrastructure construction and production operations.

Colorado

In early 2012, Ultra expanded its acreage position in eastern Colorado's Denver Julesburg Basin to 154,000 gross (139,000 net) acres. The Company drilled three vertical wells during the year to evaluate oil potential in the Cretaceous aged Niobrara formation. The Company also supported an offset operator's efforts to drill and test a Niobrara horizontal well in return for data from that well. The results of these efforts indicate the play is non-commercial, and the Company has no immediate plans for additional exploration in the area.

Marketing and Pricing

Overview

Ultra derives its revenues from the sale of its natural gas and associated condensate produced from wells operated by the Company and others in the Green River Basin in southwest Wyoming and from the sale of natural gas produced from wells operated by the Company and others in the Appalachian Basin in Pennsylvania. During 2012, 97% of the Company's production and 90% of its revenues, after realized gains on hedging transactions, were attributable to natural gas, with the balance attributable to associated condensate.

The Company's revenues are determined by prevailing natural gas market prices in the Rocky Mountain region of the United States, specifically, southwest Wyoming, and, as a result of the completion of the Rockies Express Pipeline ("REX") in 2009 and increased production in Pennsylvania during 2011 and 2012, by natural gas market prices in the Midwestern and Eastern regions of the United States.

Prevailing natural gas prices for the Company's production were lower during 2012 than over the past several years. The average realized price per Mcf for the Company's natural gas production, before realized gains on hedging transactions, for 2008, 2009, 2010, 2011 and 2012 was $7.11, $3.49, $4.31, $4.15, and $2.79, respectively. Although the Company does not believe the current low natural gas prices can be sustained, the low gas prices had an adverse effect on its results during 2012: the Company's 2012 revenues were lower than 2011 even though it achieved record annual production in 2012; the Company was required to record a $2.9 billion, non-cash, ceiling test write-down of the carrying value of its oil and gas properties during 2012; and the Company's proved undeveloped reserves at year-end 2012 were down compared to the prior year.

During 2012, the Company took several steps in response to the low gas price environment:

- Reduced net capital investment from $1.5 billion in 2011 to $615.2 million;
- Monetized its Wyoming liquids gathering system; and,
- Entered 2013 without hedging its future production at what it believes are unsustainably low forward natural gas prices.

Prevailing natural gas forward prices for the Company's future production were also lower during 2012 than over the past several years. As a result of the Company's belief that overall domestic natural gas supply will fall and natural gas forward prices will increase in response, the Company has not hedged any of its 2013 production. During 2010, 2011 and 2012, respectively, the Company hedged a substantial portion of its forecast natural gas production at an average price per Mcf of $5.54, $5.53, and $5.35. A significant portion of the Company's earnings during these years was attributable to these derivative transactions. As a result of the Company not having hedged any of its 2013 production, its earnings and cash flow may be more volatile during 2013 than in prior years.

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 and prices (daily, monthly and longer term). The Company's customer base includes a significant number of customers situated in the various regions of the United States. 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.

Midstream services. For its natural gas production in Wyoming, the Company has entered into various gathering and processing agreements with several midstream service providers that gather, compress and process natural gas owned or controlled by the Company from its producing wells in the Pinedale Anticline and Jonah fields. Under these agreements, the midstream service providers have routinely expanded their facilities' capacities in southwest Wyoming to accommodate growing volumes from wells in which the Company owns an interest. The Company believes that the capacity of the midstream infrastructure related to its production will continue to be adequate to allow it to sell essentially all of its available natural gas production.

In Pennsylvania, the Company and its partners are constructing gas gathering pipelines and facilities, compression facilities and pipeline delivery stations to gather production from its newly completed natural gas wells. Construction on these facilities continued throughout 2012, so the Company can manage its midstream capacity to coincide with capacity requirements from its drilling activities. These facilities are gathering systems and related infrastructure, and their construction is expected to continue, to some extent, until the Company's properties in Pennsylvania are fully developed. To date, none of the Company's natural gas production in Pennsylvania has required processing, treating or blending in order to remove natural gas liquids or other impurities and it is anticipated that treating facilities of this type will not be required in the future to accommodate the Company's Pennsylvania production.

Pipeline infrastructure. The Company has taken actions to facilitate expansion of the pipeline infrastructure available to move its natural gas supplies across the country, to provide sufficient capacity to transport its natural gas production and to provide for reasonable prices for its natural gas in the future. Three pipeline projects (REX, Ruby Pipeline, and Kern Pipeline's Apex Expansion) have added aggregate export pipeline capacity for Rockies/Wyoming gas of approximately 2.1 Bcf per day. The Company continues to review pipeline projects in proximity to its reserves to determine the application of the new capacity to its core business.

Basis differentials. The market price for natural gas is influenced by a number of regional and national factors which are beyond the Company's ability to control. These factors include, among others, weather, natural gas supplies, natural gas demand, inventory levels in natural gas storage fields, and natural gas pipeline capacity to export gas from the basins where the Company's production is located.

The Rocky Mountain region is a net exporter of natural gas because local natural gas production exceeds local demand, especially during non-winter months. As a result, natural gas production in southwest Wyoming has historically 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" and are reflective, to some extent, of i.) the costs associated with transporting the Company's gas to markets in other regions or states, and ii.) the availability of pipeline capacity to move the Company's gas to market.

Basis differentials in the Opal area have diminished to negligible levels when measured annually. This meaningful decrease in basis is largely attributable to the increased availability of transportation capacity out of the Rocky Mountains region due to the addition of Ruby Pipeline and Rockies Express Pipeline.

The Inside FERC First of Month Index for Northwest Pipeline — Rocky Mountains is the price that is reflective of the Company's gas sold in the Opal, Wyoming area and the Inside FERC First of Month Index for Dominion-South Pool is the price that is reflective of the Company's gas sold in Pennsylvania.

The table below provides a historical and future perspective on average annual basis differentials for Wyoming natural gas (NW Rockies) and historically premium markets in the Northeast (Dominion South). The basis differential is expressed as a percentage of the Henry Hub price as reported by Platt's M2M (Mark to Market) Report on December 31, 2012.

	2009	2010	2011	2012	2013	2014	2015
NW Rockies	77%	90%	94%	94%	96%	97%	98%
Dominion South	107%	104%	104%	100%	97%	97%	97%

Derivatives

The Company, from time to time and in the regular course of its business, hedges a portion of its natural gas production primarily through the use of financial swaps with creditworthy financial counterparties (See Note 12), or through the use of fixed price, forward sales of physical gas. The Company may elect to hedge additional portions of its forecasted natural gas production in the future, in much the same manner as it has done previously. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

As a result of the Company's belief that overall natural gas supply will fall and the low prevailing natural gas forward sale prices will improve in response, the Company has not yet entered into any hedging transactions for its 2013 production. As a result, the Company's earnings and cash flows may be more volatile during 2013 than in prior years.

The Company's hedging policy limits the amounts of resources hedged to not more than 50% of its forecast production without Board approval. As of January 1, 2010, 2011 and 2012, the quantities that the Company hedged for the succeeding twelve month periods represented 46%, 67% and 51%, respectively, of the Company's forecasted production for such periods. During 2011 and 2012, Ultra's board approved hedges of greater than 50% of the Company's forecast production for each respective period.

Oil Marketing and Liquids Gathering System

The Company markets its Wyoming condensate to various purchasers, which are primarily refiners in the Salt Lake City, Utah area. The Company's condensate realized pricing is typically based on New York Mercantile Exchange crude futures daily settlement prices, less a negotiated location/transportation discount or differential. All of the Company's condensate sales are denominated in U.S. dollars per barrel and are paid for on a monthly basis. The Company routinely maintains only operating inventories of condensate production and sells its product on an "as produced" basis. A portion of the Company's condensate sales are performed by its operating partners in the Pinedale field.

At the end of 2012, more than 80% of the Company's operated condensate production in Wyoming was delivered directly into a pipeline, further reducing truck traffic and improving flow assurance as well as realized pricing.

During December 2012, the Company entered into a Purchase and Sale Agreement (the "LGS PSA") to sell its system of liquids gathering pipelines and central gathering facilities (the "LGS") and certain associated real property rights in the Pinedale Anticline in Wyoming. The net cash proceeds received for the assets were $203.0 million and additional consideration of $23.0 million in the form of marketable securities which were sold during December 2012 for net cash proceeds of $21.2 million.

Pursuant to the LGS PSA, the Company entered into a 15-year, triple net lease agreement with the buyer relating to the use of the LGS (the "Lease Agreement"). The base rent during the Lease Agreement is $20.0 million per year (adjusted annually for changes based on the consumer price index) and may increase if certain volume thresholds are exceeded. (See Note 4).

Significant Counterparties

A significant counterparty is defined as one that individually accounts for 10% or more of the Company's total revenues during the year. In 2012, the Company had no single counterparty that represented 10% or more of the Company's total revenues.

The Company maintains credit policies intended to mitigate the risk of uncollectible accounts receivable related to the sale of natural gas and condensate as well as commodity derivatives. A more complete description of the Company's credit policies are described in Note 12. The Company did not have any outstanding, uncollectible accounts for its natural gas and oil sales at December 31, 2012.

Environmental Matters

The U.S. Bureau of Land Management ("BLM") initiates preparation of an Environmental Impact Statement ("EIS") relating to potential natural gas development on federal lands in the Pinedale Anticline area in the Green River Basin of Wyoming. An EIS is required under the National Environmental Policy Act ("NEPA") for major federal actions significantly affecting the quality of the human environment and entails consideration of environmental consequences of a proposed action and its alternatives. Although the Company 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, the area north of the Jonah field, including the Pinedale Anticline, which the EIS addresses, is where most of the Company's exploration and development is taking place. The BLM issues a Record of Decision ("ROD") with respect to a final EIS, which allows for surface disturbances for drilling and production activities within the area covered by the EIS, but does not authorize the drilling of particular wells. Ultra, therefore, must submit applications to the BLM's Pinedale field manager for permits and other required authorizations, such as rights-of-way for each specific well or particular pipeline location. In making its determination on whether to approve specific drilling or development activities, the BLM applies the requirements of the ROD.

The ROD imposes limits on drilling and completion activity and proposes mitigation guidelines, standard practices for industry activities and best management practices for sensitive areas. The Company cannot predict if or how these adjustments may affect permitting, development and compliance under the ROD. 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.

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 significant. 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 Jonah 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. 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 80-acre drilling and spacing unit. Current spacing in the Jonah field is eight 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).

The BLM prepared 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 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.

During the period from 2003 through year end 2011, Ultra and other operators in the Pinedale field received approval from the WOGCC to drill increased density and pilot project wells in several areas in the Lance Pool across the Pinedale field. During 2011, based on results of its 5-acre wells drilled in 2010, Ultra sought and obtained approval from the WOGCC to file for development of its acreage in Pinedale at a well density of 32 wells per 160-acre government quarter section (5-acre equivalent).

Ultra, Shell and Questar ("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 EIS, or SEIS, for year-round access in the Pinedale field. The SEIS process included assessment of alternative considerations and mitigation requirements that were considered as alternatives, or in addition, to those included in the proposal. The proposal included commitments to reduce surface disturbance by utilizing fewer overall pads and drilling more directional wells than called for in the 2000 Pinedale Anticline Project Area ("PAPA") ROD.

The final ROD ("2008 SEIS ROD") was granted on September 9, 2008. The 2008 SEIS ROD allows, among other things, for full field development from no more than 600 well pads field-wide, as well as year-round development and delineation activity within big game (pronghorn and mule deer) and greater sage-grouse seasonal use areas. Further, the Proponents agreed to implement numerous individual mitigation components. These commitments include (i) the use of a full-field liquids gathering system, (ii) the use of advanced rig engine emission reduction technology by at least 80% of the Company's 2005 rig emission levels, (iii) a mitigation and monitoring fund to address mitigation efforts to minimize impacts from energy development, and (iv) additional funding for ground water monitoring on the PAPA. Additionally, ten-year planning and annual meetings with BLM and appropriate state agencies will allow for proper community planning.

Also as part of the 2008 SEIS ROD, Ultra has offered to suspend additional activity for at least five years from the signing of the SEIS ROD on certain leases. After the five-year period, leases under federal suspension and/or "no surface" occupancy will be considered for conversion to "available for development" when a comparable acreage in the core area of the PAPA has been returned to a functioning habitat.

In July 2009, Ultra, along with Shell and Questar, were awarded the BLM's 2009 Environmental Best Management Practices Award for Responsible Stewardship of Air Resources in the PAPA.

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, federal, state and local regulation of oil and natural gas production and transportation, including regulations governing environmental quality, pollution control and 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.

Most states, and some counties and municipalities, in which the Company operates also regulate one or more of the following:

- The location of wells;
- The method of drilling, completing and operating wells;
- The surface use and restoration of properties upon which wells are drilled;
- Produced water and waste disposal;
- The plugging and abandoning of wells; and
- Notice to surface owners and other third parties.

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 operated by other companies that provide midstream services to the Company are also subject to the jurisdiction of various federal, state and local authorities, which can affect our operations. State laws also regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and gas properties.

States generally impose a production, ad valorem or severance tax with respect to the production and sale of oil and gas within their jurisdiction. States do not generally regulate wellhead prices or engage in other, similar direct economic regulation, but there can be no assurance they will not do so in the future.

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 Federal Energy Regulatory Commission ("FERC") under the Natural Gas Act, as well as under Section 311 of the Natural Gas Policy Act. Since 1985, the FERC has issued and 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.

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 Bureau of Land

Management ("BLM"), Bureau of Ocean Energy Management, Bureau of Safety and Environmental Enforcement, Bureau of Indian Affairs, and tribal or other applicable federal, state and/or Indian Tribal agencies.

The Mineral Leasing Act of 1920 ("Mineral Act") prohibits ownership of any direct or indirect interest in federal onshore oil and gas leases by a foreign citizen or a foreign corporation except through stock ownership in a corporation formed under the laws of the United States or of any U.S. State or territory, and only if the laws, customs, or regulations of their country of origin or domicile do not deny similar or like privileges to citizens or corporations of the United States. If these restrictions are violated, the oil and gas lease can be canceled in a proceeding instituted by the United States Attorney General. The Company qualifies as a corporation formed under the laws of the United States or of any U.S. State or territory. Although the regulations promulgated and administered by the BLM pursuant to 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 that are determined to be non-reciprocal countries under the Mineral Act. In such event, the federal onshore oil and gas leases held by the Company could be subject to cancellation based on such determination.

Surface Damage Acts

Several states, including Wyoming, and some tribal nations have enacted surface damage statutes. These laws are designed to compensate for damages caused by oil and gas development operations. Most surface damage statutes contain entry and negotiation requirements to facilitate contact between the operator and surface owners. Most also contain binding requirements for payments by the operator in connection with development operations. Costs and delays associated with surface damage statutes could impair operational effectiveness and increase development costs.

Environmental Regulations

General. The Company's exploration, drilling and production activities from wells and oil 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 federal, state and local laws and regulations relating to environmental quality, including those relating to oil spills and pollution control. Although such laws and regulations can increase the cost of planning, designing, installing and operating such facilities, it is anticipated that, absent the occurrence of an extraordinary event, compliance with them will not have a material effect upon the Company's operations, capital expenditures, earnings or competitive position.

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 or 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. Under current and evolving law, it is possible the Company could be required to remediate property, including ground water, containing or impacted by operations by the Company or by such third party operators, or by previously disposed wastes including performing remedial plugging operations to prevent future, or mitigate existing, contamination.

Although oil and gas wastes generally are exempt from regulation as hazardous wastes ("Hazardous Wastes") under the federal Resource Conservation and Recovery Act ("RCRA") and some comparable state statutes, it is possible some wastes the Company generates presently or in the future may be subject to regulation under RCRA and state analogs. The Environmental Protection Agency ("EPA") and various state agencies have limited the disposal options for certain wastes, including Hazardous Wastes and are 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 designation as Hazardous Wastes may in the future be designated as Hazardous Wastes under RCRA or other applicable statutes, and therefore be subject to more rigorous and costly operating and disposal requirements.

Hydraulic Fracturing. Many of the Company's exploration and production operations depend on the use of hydraulic fracturing to enhance production from oil and gas wells. Congress has periodically considered legislation to amend the federal Safe Drinking Water Act to remove the exemption from permitting and regulation provided to injection for hydraulic fracturing and to require the disclosure and reporting of the chemicals used in hydraulic fracturing (except where diesel is a component of the fracturing fluid). This type of federal legislation, if adopted, could lead to additional regulation and permitting requirements that could result in operational delays making it more difficult to perform hydraulic fracturing and increasing our costs of compliance and operating costs.

In addition, EPA has recently been considering whether to assert federal regulatory authority over hydraulic fracturing using diesel under the Safe Drinking Water Act's Underground Injection Control Program. Further, in March 2010, the EPA announced that it would conduct a wide-ranging study on the effects of hydraulic fracturing on drinking water resources. EPA released a progress report in December 2012 and final results are expected in 2014. In addition, in December 2011, the EPA published a draft report in which it asserts that hydraulic fracturing caused groundwater pollution in a natural gas field in Wyoming (not a field in which the Company owns any interest); this report has been publicly criticized by industry and government officials, including the Governor of Wyoming; it remains subject to review. The agency also announced that one of its enforcement initiatives for 2011 to 2013 would be to focus on environmental compliance by the energy extraction sector. This study and enforcement initiative could result in additional regulatory scrutiny that could make it difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

In addition, some states have adopted, and other states have adopted or are considering adopting, regulations that require disclosure of the chemicals in the fluids used in hydraulic fracturing. Additionally, some states, localities and local regulatory districts have adopted or have considered adopting regulations to limit, and in some case impose a moratorium on hydraulic fracturing. Although none of the Company's properties are in jurisdictions where the limits have been imposed, it is possible the jurisdictions where the Company's properties are located may adopt such limits or other limits on hydraulic fracturing in the future. The BLM has proposed rules and regulations for hydraulic fracturing activities on federal lands. The Company and others provided written comment to the proposed rules. Further, the EPA has announced an initiative under The Toxics Substances Control Act to develop regulations governing the disclosure and evaluation of hydraulic fracturing chemicals.

Superfund. Under the federal Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, liability, generally, is joint and several 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 releases and threats of releases to protect 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, as a past or present owner or operator or as an arranger. Many states have comparable laws imposing liability on similar classes of persons for releases, including for releases of materials that may not be included in CERCLA's definition of Hazardous Substances. To its knowledge, the Company has not been named a PRP under CERCLA (or any comparable state law) nor have any prior owners or operators of its properties been named as PRPs related to their ownership or operation of such property.

National Environmental Policy Act. The federal National Environmental Policy Act provides that, for major federal actions significantly affecting the quality of the human environment, the federal agency taking such action must prepare an environmental assessment or an environmental impact statement (EIS). In the EIS, the agency is required to evaluate alternatives to the proposed action and the environmental impacts of the proposed action and of such alternatives. Actions of the Company, such as drilling on federal lands, to the extent the drilling requires federal approval, may trigger the requirements of the National Environmental Policy Act, including the requirement that an EIS be prepared. The requirements of the National Environmental Policy Act may result in increased costs, significant delays and the imposition of restrictions or obligations on the Company's activities, including but not limited to the restricting or prohibiting of drilling.

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. OPA assigns liability, which generally is joint and several, without regard to fault, to each liable party for oil removal costs and for 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, the 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 generally require new and modified sources of air pollutants to obtain permits prior to commencing construction, which may require, among other things, stringent, technical controls. Other federal and state laws designed to control hazardous (toxic) air pollutants might require installation of additional controls. Administrative agencies can bring actions for failure to comply with air pollution regulations or permits and generally enforce compliance through administrative, civil or criminal enforcement actions, which may result in fines, injunctive relief and imprisonment.

On April 17, 2012, the EPA issued final rules to subject oil and gas operations to regulation under the New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAPS") programs under the Clean Air Act ("CAA"), and to impose new and amended requirements under both programs. The EPA rules include NSPS standards for completions of hydraulically fractured natural gas wells. Before January 1, 2015, these standards require operators of oil and gas wells to reduce emissions of volatile organic compounds ("VOCs") during completions by either flaring or capturing any natural gas not delivered into gathering pipelines in a process commonly referred to as a "green completion." During 2012, the Company conducted "green completions" on all of the wells it hydraulically fractured. In addition, the rules establish new requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, natural gas processing plants, and certain other equipment. These rules may require changes to our operations, including possible installation of new equipment to control emissions. We are currently evaluating the effect these rules will have on our business.

Clean Water Act. The Clean Water Act ("CWA") restricts the discharge of pollutants, including produced waters and other oil and natural gas wastes, into waters of the United States, a term broadly defined to include, among other things, certain wetlands. Under the Clean Water Act, permits must be obtained for the discharge of pollutants into waters of the United States. The CWA provides for administrative, civil and criminal penalties for unauthorized discharges, both routine and accidental, 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. The CWA also prohibits the discharge of fill materials to regulated waters including wetlands without a permit.

Endangered Species Act. The Endangered Species Act ("ESA") was established to protect endangered and threatened species. Pursuant to that act, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The Company conducts operations on federal and other oil and natural gas leases that have species, such as raptors, that are listed and species, such as sage grouse, that could be listed as threatened or endangered under the ESA. 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 or the mere presence of threatened or endangered species could result in further material restrictions to land use and may materially delay or prohibit land access for oil and natural gas development. If the 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.

Climate Change Legislation. More stringent laws and regulations relating to climate change and greenhouse gases ("GHGs"), including methane and carbon dioxide, may be adopted and could cause the Company to incur material expenses in complying with them. The EPA has adopted rules under the CAA for the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration and Title V permitting programs. The EPA has adopted a multi-tiered approach to this permitting, with the largest sources being subjected to the permitting requirements first. These permitting provisions, should they become applicable to our operations, could require controls or other measures to reduce GHG emissions from new or modified sources, and the Company could incur additional costs to satisfy those requirements. In November 2010, EPA published a rule establishing GHG reporting requirements for sources in the petroleum and natural gas industry, requiring those sources to monitor, maintain records on, and annually report their GHG emissions, with the first annual report, for 2011, being due in September 2012. Although the rule does not limit the amount of GHGs that can be emitted, it could require us to incur significant costs to monitor, keep records of, and report GHG emissions associated with our operations.

In addition to possible federal regulation, a number of states, individually and regionally, also are considering or have implemented GHG regulatory programs. These or other potential federal and state initiatives may result in so-called cap-and-trade programs, under which overall GHG emissions are limited and GHG emissions are then allocated and sold, and possibly other regulatory requirements, that could result in the Company incurring material expenses to comply, e.g., by being required to purchase or to surrender allowances for GHGs resulting from its operations. These regulatory initiatives also could adversely affect the marketability of the oil and natural gas the Company produces.

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, 2012, the Company had 115 full-time employees, including officers.

Item 1A. *Risk Factors.*

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, 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, prices and future operating costs 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.

The present value, discounted at 10%, of the pre-tax future net cash flows attributable to our net proved reserves included in this report should not be considered as the market value of the reserves attributable to our properties. In accordance with SEC requirements, we base the present value, discounted at 10%, of the pre-tax future net cash flows attributable to our net proved reserves on the average oil and natural gas prices during the 12-month period before the ending date of the period covered by this report determined as an unweighted, arithmetic average of the first-day-of the-month price for each month within such period, adjusted for quality and transportation. The costs to produce the reserves remain constant at the costs prevailing on the date of the estimate. Actual current and future prices and costs may be materially higher or lower. In addition, the 10% discount factor, which the SEC requires us to use in calculating our discounted future net revenues for reporting purposes, may not be the most appropriate discount factor based on our cost of capital from time to time and/or the risks associated with our business.

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

We compete with numerous other companies in virtually all facets of our business. Our 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 our financial or personnel resources permit. We also compete for the materials, equipment and services that are necessary for the exploration, development and operation of our properties. 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 and complete 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;

- our ability to procure materials, equipment and services required to explore, develop and operate our properties; and
- our ability to access 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, including facilities owned and operated by third parties;
- the proximity of natural gas production to 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 transportation; and
- federal regulation of natural gas sold or transported in interstate commerce.

Because of these factors, we may be unable to market all of the oil and natural gas that we produce. In addition, we may be unable to obtain favorable prices for the oil and natural gas we produce.

Any derivative transactions we enter into may limit our gains and expose us to other risks.

Although we have not entered into any derivative transactions related to our 2013 production, we do enter into transactions with derivative instruments from time to time to manage our exposure to commodity price risks. These transactions limit our potential gains if commodity prices rise above the levels established by our derivative instruments. These transactions may also expose us to other risks of financial losses, for example, if our production is less than we anticipated at the time we entered into a derivative instrument or if a counterparty to our derivative instruments fails to perform the contracts.

The adoption of derivatives legislation and regulations related to derivative contracts could have an adverse impact on our ability to hedge risks associated with our business.

During 2010, the President signed into law the Dodd–Frank Wall Street Reform and Consumer Protection Act (the "Act"). Among other things, the Act requires the Commodity Futures Trading Commission (the "CFTC") and the SEC to enact regulations affecting derivative contracts, including the derivative contracts we use to hedge our exposure to price volatility through the over-the-counter market.

In its rulemaking under the new legislation, the CFTC has issued a final rule on position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents (with exemptions for certain bona fide hedging transactions); the CFTC's final rule was set aside by the U.S. District Court for the District of Columbia on September 28, 2012 and remanded to the CFTC to resolve ambiguity as to whether statutory requirements for such limits to be determined necessary and appropriate were satisfied. As a result, the rule has not yet taken effect, although the CFTC has indicated that it intends to appeal the court's decision and that it believes the Dodd-Frank Act requires it to impose position limits. The impact of such regulations upon our business is not yet clear. Certain of our hedging and trading activities and those of our counterparties may be subject to the position limits, which may reduce our ability to enter into hedging transactions.

In addition, the Act does not explicitly exempt end users (such as us) from the requirement to use cleared exchanges, rather than hedging over-the-counter, and the requirements to post margin in connection with hedging activities. While it is not possible at this time to predict when the CFTC will finalize certain other related rules and regulations, the Act and related regulations may require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although whether these requirements will apply to our business is uncertain at this time. If the regulations ultimately adopted require that we post margin for our hedging activities or require our counterparties to hold margin or maintain capital levels, the cost of which could be passed through to us, or impose other requirements that are more burdensome than current regulations, hedging transactions in the future would become more expensive than we experienced in the past.

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

Energy commodity prices 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. Unless and until we enter into any derivative transactions related to our 2013 production, our revenues and cash flow may be more volatile during 2013 than in prior years. Information about revenues attributable to our derivative transactions in 2010, 2011 and 2012 is available in Item 7-A — “Quantitative and Qualitative Disclosures About Market Risk.”

Oil and natural gas prices are subject to a variety of additional factors beyond our control, which include, but are not limited to: changes in the supply of and demand for oil and natural gas; market uncertainty; 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; 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 substantial portion of our reserves and production is natural gas. Prices for natural gas have been lower in recent years than at various times in the past and may remain lower in the future. The low natural gas prices during the past year adversely affected our 2012 revenues, cash flow and reserves. Sustained low prices for natural gas during 2013 and beyond may also adversely affect our operational and financial condition.

Natural gas prices have been lower in recent years than at various times in the past. These lower prices may be the result of increased supply resulting from among other things, increased drilling in unconventional reservoirs and/or lower demand resulting from reduced economic activity associated with the recent recession. Natural gas prices may remain at current levels, or fall to lower levels, in the future. Approximately 96% of our estimated net proved reserves is natural gas, and 97% of our production in 2012 was natural gas. Although we expect production operations on properties we currently own to be profitable at natural gas prices in effect during the past year, a continued period of sustained low natural gas prices could have further adverse effects on our results of operations and financial condition.

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 relating to environmental protection. These laws and regulations may:

- require that we acquire permits before developing our properties;
- 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; and
- require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells.

Under these laws and regulations or under the common law, the Company could be liable for personal injury and clean-up costs and other environmental, natural resource and property damages, as well as administrative, civil and criminal penalties. The Company could also be affected by more stringent laws and regulations adopted in the future, including any related to climate change, engine emissions, greenhouse gases and hydraulic fracturing. 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 accidental environmental damages. Accordingly, we may be subject to liability in excess of our insurance coverage or may be required to cease production from properties in the event of environmental damages.

A significant percentage of our operations are conducted on federal and state lands. These operations are subject to a wide variety of regulations as well as other permits and authorizations which must be obtained from and issued by state and federal agencies. To conduct these operations, we may be required to file applications for permits, seek agency authorizations and comply with various other statutory and regulatory requirements. Complying with any of these requirements may adversely affect our ability to complete our drilling programs at the costs and in the time periods anticipated.

Climate change legislation or regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the oil and gas we produce.

More stringent laws and regulations relating to climate change and GHGs may be adopted and could cause the Company to incur material expenses to comply. The EPA has adopted rules under the CAA for the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration and Title V permitting programs. These permitting provisions, should they become applicable to our operations, could require controls or other measures to reduce GHG emissions from new or modified sources, and the Company could incur additional material costs to satisfy those requirements.

In addition, on October 30, 2009, the EPA published a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the United States beginning in 2011 for emissions occurring in 2010. On November 30, 2010, the EPA published its amendments to the GHG reporting rule to include onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage and distribution facilities, which may include facilities we operate. Reporting of GHG emissions from such facilities will be required on an annual basis beginning in 2012 for emissions occurring in 2011. We will have to incur costs associated with this reporting obligation.

In addition, the United States Congress has considered legislation to reduce emissions of GHGs and many states have already taken legal measures to reduce or measure GHG emission levels, often involving the planned development of GHG emission inventories and/or regional cap and trade programs. Most of these cap and trade programs require major sources of emissions or major producers of fuels to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to reduce overall

GHG emissions. The cost of these allowances could escalate significantly over time. The adoption and implementation of any legislation or regulatory programs imposing GHG reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas that we produce.

Potential physical effects of climate change could adversely affect our operations and cause us to incur significant costs in preparing for or responding to those effects.

In an interpretative guidance on climate change disclosures, the SEC indicates that climate change could have an effect on the severity of weather (including hurricanes and floods), sea levels, the arability of farmland, and water availability and quality. If such effects were to occur, our exploration and production operations, including the hydraulic fracturing of our wells, have the potential to be adversely affected. Potential adverse effects could include disruption of our production activities, including, for example, damages to our facilities from powerful winds or increases in our costs of operation or reductions in the efficiency of our operations, as well as potentially increased costs for insurance coverages in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change.

Federal legislation and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions but is not subject to regulation at the federal level (except for fracturing activity involving the use of diesel). The EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, issued a progress report in December 2012, and expects to deliver the final results of the study in 2014. In addition, in December 2011, the EPA published a draft report in which it asserts that hydraulic fracturing caused groundwater pollution in a natural gas field in Wyoming (not a field in which the Company owns an interest); this report has been publicly criticized by industry and by government officials, including the Governor of Wyoming; it remains subject to review. A committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. Legislation was introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. Pennsylvania has adopted a variety of regulations limiting how and where fracturing can be performed. Wyoming has adopted regulations requiring us to provide detailed information about wells we hydraulically fracture in that state. Many other states have adopted or are considering adopting regulations requiring disclosure of chemicals in fluids used in hydraulic fracturing. Any other new laws or regulations that significantly restrict hydraulic fracturing could make it more difficult or costly for us to perform hydraulic fracturing activities and thereby affect our determination of whether a well is commercially viable. In addition, if hydraulic fracturing is regulated at the federal level, our fracturing activities could become subject to additional permit requirements or operational restrictions and also to associated permitting delays and potential increases in costs. We have conducted hydraulic fracturing operations on most of our existing wells, and we anticipate conducting hydraulic fracturing operations on substantially all of our future wells. As a result, restrictions on hydraulic fracturing could reduce the amount of oil and natural gas that we are ultimately able to produce in commercial quantities.

Cyber-attacks targeting systems and infrastructure used by the oil and gas industry may adversely impact our operations.

Our business has become increasingly dependent on digital technologies to conduct certain exploration, development, production and financial activities. We depend on digital technology to estimate quantities of oil and gas reserves, process and record financial and operating data, analyze seismic and drilling information, and communicate with our employees and third party partners. Unauthorized access to our seismic data, reserves information or other proprietary information could lead to data corruption, communication interruption, or other operational disruptions in our exploration or production operations. Also, computers control nearly all of the oil and gas distribution systems in the United States and abroad, which are necessary to transport our production to market. A cyber-attack directed at oil and gas distribution systems could damage critical distribution and storage assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for production and settle transactions.

While we have not experienced cyber-attacks, there is no assurance that we will not suffer such attacks and resulting losses in the future. Further, as cyber-attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber-attacks.

We may not be able to obtain funding on acceptable terms or at all.

Global financial markets and economic conditions have been disrupted and volatile due to a variety of factors. As a result, the cost of raising money in the debt and equity capital markets and the availability of funds from those markets is unpredictable. Although we successfully raised capital in the past, we may not be successful in the future. In addition, lending counterparties under existing revolving credit facilities and other debt instruments may be unwilling or unable to meet their funding obligations. Due to these factors, we cannot be certain that new debt or equity financing will be available on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to meet our obligations as they come due and we may be unable to execute our growth strategy, take advantage of other business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our revenues and results of operations.

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 loan commitment and aggregate amount of money we can borrow under the credit facility and from other sources is revised from time to time based on certain restrictive covenants. A change in our ability to meet the restrictive covenants might limit our ability to borrow. If this occurred, we may have to sell assets or seek substitute financing. 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.

Our operations are conducted primarily in the Rocky Mountain region of the United States and in the north-central Pennsylvania area of the Appalachian Basin. The weather in these areas 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 operations are subject to disruption from winter storms and severe cold, which can limit operations involving fluids and impair access to our facilities.

Unless we are able to replace reserves that 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 blowouts, fire, explosion, pipe failure, casing collapse, abnormally pressured formations, and environmental hazards such as oil spills, natural gas leaks, discharges of toxic gases, underground migration and surface spills or mishandling of fracture fluids, including chemical additives. 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 and completing 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 and possible liabilities. 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.

A prospect is an area in 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 our prospects depends on many factors, including but not limited to: 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; the availability and cost of capital; changes in the estimates of costs to drill or complete wells; decisions of our joint working interest owners; and regulatory and permitting requirements. It is possible that these factors and others 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 record additional 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. Discounted future net revenues are estimated using oil and natural gas spot prices based on the average price during the preceding 12-month period determined as an unweighted, arithmetic average of the first-day-of-the-month price for each month within such period, 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. As a result of low gas prices during 2012, we were required to record a $2.9 billion non-cash, ceiling test write-down of the carrying value of our oil and gas properties.

We have limited control over activities conducted on properties we do not operate.

We own interests in properties that are operated by third parties. The success, timing and costs of drilling, completion, and other development activities on our non-operated properties depend on a number of factors that are beyond our control. Because we have only a limited ability to influence and control the operations of our non-operated properties, we can give no assurances that we will realize our targeted returns with respect to those properties.

We may fail to fully identify problems with any properties we acquire.

We acquired a portion of our acreage position in Pennsylvania and Colorado through property acquisitions and acreage trades, and we may acquire additional acreage in Colorado, Pennsylvania or other regions in the future. Although we conduct a review of properties we acquire which we believe is consistent with industry practices, we can give no assurance that we have identified or will identify all existing or potential problems associated with such properties or that we will be able to mitigate any problems we do identify.

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. Except for statements of historical facts, all statements included in this document, including 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;
- our ability to respond to low natural gas prices;

- 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:

- any future global economic downturn;
- general economic conditions, including the availability of credit and access to existing lines of credit;
- 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 exploration for and production of oil and natural gas;
- difficulties encountered during the exploration 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 and obtain financing on favorable terms;
- compliance with, or the effect of changes in, the extensive governmental regulations regarding the oil and natural gas business, including those related to climate change and greenhouse gases;
- 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 owns oil and natural gas leases in Wyoming and Pennsylvania and oil and gas leases and fee minerals in Colorado. The leases in Wyoming are primarily federal leases with 10-year lease terms until establishment of production. Production extends the lease terms until cessation of that production. In Pennsylvania, the leases are from private individuals and companies, as well as from the Commonwealth of Pennsylvania. The leases in Pennsylvania are mostly undeveloped at this time and typically have primary lease terms of five years until establishment of production. In Colorado, our oil and gas leases are from private individuals and companies, as well as from the State of Colorado, and typically have primary lease terms of five years. All of our acreage in Colorado is undeveloped at this time, and the Company has no immediate plans for further exploration in this area.

Green River Basin, Wyoming

As of December 31, 2012, the Company owned developed oil and natural gas leases totaling approximately 84,000 gross (49,000 net) acres in the southwest Wyoming's Green River Basin. Most of this acreage covers Pinedale and Jonah fields. Of the total acreage position in Wyoming, approximately 22,000 gross (10,000 net) acres were developed, and 62,000 gross (39,000 net) acres were undeveloped. The developed portion represents 15% of the Company's total developed net acreage while the undeveloped portion represents approximately 10% of the Company's total undeveloped net acreage.

Lease maintenance costs in Wyoming were approximately $0.1 million for the year ended December 31, 2012. The Company currently owns 39 leases totaling 68,000 gross (37,000 net) acres currently held by production and activities ("HBP") in Wyoming. The HBP acreage includes all of the Company's leases within the productive area of the Pinedale and Jonah fields.

Development Wells. During 2012, the Company participated in the drilling of 81 gross (30.6 net) productive development wells on the Green River Basin properties. At year-end 2012, there were 16 gross (5.7 net) additional development wells that commenced during the year and were either still drilling or had operations suspended at a depth short of total depth.

Exploratory Wells. During 2012, the Company participated in the drilling of a total of 30 gross (13.6 net) productive exploratory wells on the Green River Basin properties. At December 31, 2012, there were 8 gross (6.4 net) additional exploratory wells that commenced during the year that were either still drilling or had operations suspended at a depth short of total depth and thus a determination of productive capability could not be made at year-end.

Pennsylvania

As of December 31, 2012, the Company owned oil and gas leases covering 497,000 gross (261,000 net) acres in the Pennsylvania portion of the Appalachian Basin. This acreage is located in the heart of northeast Pennsylvania's Marcellus Shale Gas Trend, principally in Potter, Tioga, Lycoming, Centre and Clinton counties. Of the total acreage position as of December 31, 2012, approximately 111,000 gross (58,000 net) acres were developed, and 386,000 gross (203,000 net) acres were undeveloped. The developed portion represents 85% of the Company's total developed net acreage position while the undeveloped portion represents 53% of the Company's total undeveloped net acreage position. The Company operates approximately 84,000 gross (58,000 net) acres of the total position.

Lease maintenance costs in Pennsylvania were approximately $2.0 million for the year ended December 31, 2012. The Company owns approximately 362,000 gross (185,000 net) acres currently held by production or activities in Pennsylvania.

Development Wells. During 2012, the Company participated in the drilling of 16 gross (8.0 net) productive development wells in Pennsylvania, all of which were horizontal wells. At year-end 2012, there was 1 gross (0.5 net) additional development wells that commenced during the year and were either still drilling or had operations suspended at a depth short of total depth.

Exploratory Wells. During the year ended December 31, 2012, the Company participated in the drilling of a total of 48 gross (18.9 net) productive exploratory wells on the Pennsylvania properties. At December 31, 2012, there was 1 gross (0.5 net) additional exploratory well that commenced during the year that was either still drilling or had operations suspended at a depth short of total depth and thus a determination of productive capability could not be made at year-end.

Seismic Activity. The Company acquired 148 square miles of new 3D seismic data on its properties during 2012. The Company's total 3D seismic coverage in Pennsylvania is 455 square miles. Of this, 425 square miles of data is owned with other parties, and 30 square miles is owned solely by the Company.

Denver Julesburg Basin, Colorado

As of December 31, 2012, the Company owned fee minerals and oil and gas leases covering 154,000 gross (139,000 net) acres in eastern Colorado's Denver Julesburg Basin. The total acreage in Colorado represents approximately 36% of the Company's undeveloped net acreage position.

Lease maintenance costs in Colorado were $0.1 million for the year ended December 31, 2012. All of the Colorado acreage is undeveloped at this time; none of it is held by production. The Company has no immediate plans for further exploration in this area.

Exploratory Wells. During 2012, the Company drilled 3 gross (3.0 net) exploratory wells in eastern Colorado. All three were vertical wells designed to evaluate oil potential in the Niobrara Formation.

Development Wells. The Company did not participate in drilling any development wells in Colorado during 2012.

Seismic Activity. The Company did not acquire any additional seismic data in Colorado during 2012. The Company currently owns 22 square miles of 3D seismic data in El Paso County, Colorado, and has licensed an additional 126 linear miles of 2D data in the same county. This represents the Company's total seismic position in the area.

Oil and Gas Reserves

The following table sets forth the Company's quantities of proved reserves for the years ended December 31, 2012, 2011, and 2010 as estimated by independent petroleum engineers Netherland, Sewell & Associates, Inc. The table summarizes the Company's 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, 2012, 2011 and 2010. As of December 31, 2012, proved undeveloped reserves represent 38.7% of the Company's total proved reserves.

	December 31,		
	2012	2011	2010
Proved Developed Reserves			
Natural gas (MMcf)	1,820,994	1,973,391	1,678,697
Oil (MBbl)	10,531	11,794	11,013
Proved Undeveloped Reserves			
Natural gas (MMcf)	1,145,451	2,805,163	2,521,458
Oil (MBbl)	7,606	21,287	20,671
Total Proved Reserves (MMcfe)(1)	3,075,267	4,977,040	4,390,257
Estimated future net cash flows, before income tax	$4,501,804	$11,789,256	$10,879,719
Standardized measure of discounted future net cash flows, before income taxes(2)	$2,263,259	$ 5,296,964	$ 4,993,576
Future income tax	$ 368,942	$ 1,500,908	$ 1,468,008
Standardized measure of discounted future net cash flows, after income tax	$1,894,317	$ 3,796,056	$ 3,525,568
Calculated average price(3)			
Gas ($/Mcf)	$ 2.63	$ 4.04	$ 4.05
Oil ($/Bbl)	$ 87.85	$ 88.19	$ 68.93

(1) Oil and condensate are converted to natural gas at the ratio of one barrel of oil or condensate to six Mcf of natural gas. This conversion ratio, which is typically used in the oil and gas industry, represents the approximate energy equivalent of a barrel of oil or condensate to an Mcf of natural gas. The sales price of one barrel of oil or condensate has been much higher than the sales price of six Mcf of natural gas over the last several years, so a six to one conversion ratio does not represent the economic equivalency of six Mcf of natural gas to one barrel of oil or condensate.

(2) 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-Generally Accepted Accounting Principle 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 Generally Accepted Accounting Principle ("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.

(3) As prescribed by Securities and Exchange Commission ("SEC") Release No. 33-8995, Modernization of Oil and Gas Reporting Requirements ("SEC Release No. 33-8995"), reserves estimated by our independent engineers at December 31, 2012, 2011 and 2010, reflect oil and natural gas spot prices based on the average prices during the 12-month period before the ending date of the period covered by this report determined as an unweighted, arithmetic average of the first-day-of-the-month price for each month within such period.

Since January 1, 2012, no crude oil or natural gas reserve information has been filed with, or included in any report to, any federal authority or agency other than the SEC and the Energy Information Administration ("EIA") of the U.S. Department of Energy. We file Form 23, including reserve and other information, with the EIA.

Proved Undeveloped Reserves

The following table describes the changes in the Company's proved undeveloped reserves during 2012:

	MMcfe
Proved undeveloped reserves, December 31, 2011	2,932,885
Converted to proved developed	(172,736)
Proved undeveloped reserve extensions	756,595
Proved undeveloped reserves transferred to unproven	(2,311,045)
Proved undeveloped reserve revisions	(14,612)
Proved undeveloped reserves, December 31, 2012	1,191,087

In 2012, the Company converted 173 Bcfe of proved undeveloped reserves to proved developed reserves. Of these conversions, 89% were located in the Pinedale field in Wyoming. During 2012, the Company spent $207.0 million to convert proved undeveloped reserves to proved developed reserves. At December 31, 2012, the Company also transferred 2.3 Tcfe of proved undeveloped reserves to the unproven category of reserves due to lower natural gas prices utilized in the preparation of the December 31, 2012 reserve estimation. The natural gas price utilized in preparing the Company's reserve estimate at December 31, 2012 was $2.63 per Mcf as compared to $4.04 per Mcf at December 31, 2011, a 35% decrease. At the lower gas price, some of the Company's proved undeveloped locations are uneconomic and, accordingly, the Company transferred these locations to the unproven category.

In addition to lower gas prices, the Company reduced the capital scheduled for proved undeveloped locations to $1.4 billion at December 31, 2012 from $4.1 billion at December 31, 2011. This reduction in capital was largely associated with certain other proved undeveloped locations transferred to the unproven category. The Company has not scheduled any proved undeveloped reserves beyond five years nor does it have any proved undeveloped locations that have been part of its inventory of proved undeveloped locations for over five years.

During 2012, the Company recorded a $2.9 billion non-cash write-down of the carrying value of the Company's proved oil and gas properties as a result of ceiling test limitations, which is reflected with ceiling test and other impairments in the accompanying Consolidated Statements of Operations.

Internal Controls Over Reserve Estimating Process

Our policies and practices regarding internal controls over the recording of reserves is structured to objectively and accurately estimate our oil and gas reserves quantities and present values in compliance with the SEC's regulations and GAAP. The Vice President — Reservoir Engineering & Development is primarily responsible for overseeing the preparation of the Company's reserve estimates by our independent engineers, Netherland, Sewell & Associates, Inc. The Vice President — Reservoir Engineering and Development has a Bachelor and Master of Science degree in Petroleum Engineering and is a licensed Professional Engineer with over 18 years of experience. The Company's internal controls over reserve estimates include reconciliation and review controls, including an independent internal review of assumptions used in the estimation. Our internal professional staff works closely with our independent engineers to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process. In addition, other pertinent data is provided such as seismic information, geologic maps, well logs, production tests, well performance data, operating procedures and relevant economic criteria. We make available all information requested, including our pertinent personnel, to the external engineers as part of their evaluation of our reserves.

All of the information regarding reserves in this annual report is derived from the report of Netherland, Sewell & Associates, Inc. The report of Netherland, Sewell & Associates, Inc. is included as an Exhibit to this annual report. The principal engineer at Netherland, Sewell & Associates, Inc. responsible for preparing our reserve estimates has a Bachelor of Science degree in Mechanical Engineering and is a licensed Professional Engineer with 30 years of experience, including significant experience throughout the Rocky Mountain basins.

In estimating proved reserves and future net revenue as of December 31, 2012, the Company's independent reserve engineer, Netherland, Sewell & Associates, Inc., used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information and property ownership interests. The reserves were estimated using deterministic methods; these estimates were prepared in accordance with generally accepted petroleum engineering and evaluation principles. Standard engineering and geoscience methods, such as reservoir modeling, performance analysis, volumetric analysis and analogy, that were considered to be appropriate and necessary to establish reserve quantities and reserve categorization that conform to SEC definitions and rules and regulations, were also used. As in all aspects of oil and natural gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, Netherland, Sewell & Associates, Inc.'s conclusions necessarily represent only informed professional judgment.

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,		
	2012	2011	2010
	(In thousands, except per unit data)		
Production			
Natural gas (Mcf)	249,310	236,832	205,613
Oil (Bbl)	1,282	1,408	1,334
Total (Mcfe)	257,002	245,280	213,619
Revenues			
Natural gas sales	$695,733	$ 982,413	$886,396
Oil sales	114,241	119,383	92,990
Total revenues	$809,974	$1,101,796	$979,386
Lease Operating Expenses			
Production costs(a)	$ 64,468	$ 51,758	$ 45,938
Severance/production taxes	60,757	97,094	95,914
Gathering	59,004	56,511	50,126
Total lease operating expenses	$184,229	$ 205,363	$191,978
Realized prices			
Natural gas ($/Mcf, including realized gains (losses) on commodity derivatives)	$ 4.01	$ 5.05	$ 4.88
Natural gas ($/Mcf, excluding realized gains (losses) on commodity derivatives)	$ 2.79	$ 4.15	$ 4.31
Oil ($/Bbl)	$ 89.08	$ 84.79	$ 69.69
Costs per Mcfe			
Production costs	$ 0.25	$ 0.21	$ 0.22
Severance/production taxes	$ 0.24	$ 0.40	$ 0.45
Gathering	$ 0.23	$ 0.23	$ 0.23
Transportation charges	$ 0.33	$ 0.26	$ 0.30
DD&A	$ 1.51	$ 1.41	$ 1.13
General & administrative	$ 0.10	$ 0.11	$ 0.11
Interest	$ 0.34	$ 0.26	$ 0.23
Total costs per Mcfe	$ 3.00	$ 2.88	$ 2.68

The following table sets forth the net sales volumes, operating expenses and realized natural gas prices attributable to field(s) that contain 15% or more of our total estimated proved reserves as of December 31, 2012:

	Year ended December 31,		
	2012	2011	2010
	(In thousands)		
Pinedale Field:			
Production (Mcfe)	179,757	196,236	190,849
Operating expenses	$144,538	$178,387	$179,544
Realized price, excluding hedges ($/Mcf)	$ 2.84	$ 4.17	$ 4.32
Realized price, including hedges ($/Mcf)	$ 4.55	$ 5.27	$ 4.94

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

Delivery Commitments

With respect to the Company's natural gas production, from time to time the Company enters into transactions to deliver specified quantities of gas to its customers. As of February 8, 2013, the Company had long-term natural gas delivery commitments of 3.0 MMMBtu in 2013, 8.2 MMMBtu in 2014, 4.4 MMMBtu in 2015, 4.8 MMMBtu in 2016 and 7.9 MMMBtu in 2017 under existing agreements. None of these commitments require the Company to deliver gas produced specifically from any of the Company's properties, and all of these commitments are priced on a floating basis with reference to an index price. These amounts are well below the Company's forecasted 2013 and anticipated 2014 through 2017 production from its available reserves. In addition, none of the Company's reserves are subject to any priorities or curtailments that may affect quantities delivered to its customers, any priority allocations or price limitations imposed by federal or state regulatory agencies or any other factors beyond the Company's control that may affect its ability to meet its contractual obligations other than those discussed in Item 1A. "Risk Factors". The Company believes that its production and reserves are adequate to meet its delivery commitments. If for some reason the Company's production is not sufficient to satisfy its delivery commitments, the Company expects to be able to purchase natural gas production in the market to satisfy its commitments.

With respect to the Company's oil production, the Company does not have any long-term arrangements that commit the Company to deliver a fixed or determinable quantity of oil in the near future.

Productive Wells

As of December 31, 2012 the Company's total gross and net wells were as follows:

Productive Wells*	Gross Wells	Net Wells
Natural Gas and Condensate	2,334	1,145.5

* Productive wells are producing wells, shut-in wells the Company deems capable of production, wells that are waiting for completion, plus wells that are drilled/cased and completed, but waiting for pipeline hook-up. 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

The primary terms of the Company's oil and gas leases expire at various dates. Much of the Company's undeveloped acreage is held by production, which means that the Company will maintain its rights in these leases as long as oil or natural gas is produced from the acreage by it or by other parties holding interests in producing wells on those leases. In some cases, if production from a lease ceases, the lease will expire, and in some cases, if production from a lease ceases, the Company may maintain the lease by additional operations on the acreage.

The Company does not believe the remaining terms of its leases is material. At December 31, 2012, the Company had 12,245 net acres of leases in Pennsylvania, 2,000 net acres of leases in Colorado and no leases in Wyoming that expire in 2013 and it expects to maintain over 20% of those leases by production, operations, extensions or renewals. The Company does not expect to lose material lease acreage because of failure to drill due to inadequate capital, equipment or personnel. The Company has, based on its evaluation of prospective economics, allowed acreage to expire and it may allow additional acreage to expire in the future.

As of December 31, 2012 the Company had total gross and net developed and undeveloped oil and natural gas leasehold acres in the United States as set forth below.

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
Wyoming	22,000	10,000	62,000	39,000
Pennsylvania	111,000	58,000	386,000	203,000
Colorado	—	—	154,000	139,000
All States	133,000	68,000	602,000	381,000

Drilling Activities

For each of the three fiscal years ended December 31, 2012, 2011 and 2010 the number of gross and net wells drilled by the Company was as follows:

Wyoming — Green River Basin

	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	81.0	30.6	117.0	71.0	75.0	37.3
Dry	—	—	—	—	—	—
Total	81.0	30.6	117.0	71.0	75.0	37.3

At year end, there were 16 gross (5.7 net) additional development wells that were either drilling or had operations suspended. This includes wells in both the Pinedale and Jonah fields.

	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive	30.0	13.6	83.0	42.5	106.0	57.2
Dry	—	—	—	—	—	—
Total 30.0 13.6	30.0	13.6	83.0	42.5	106.0	57.2

At year end, there were 8 gross (6.4 net) additional exploratory wells that were either drilling or had operations suspended. This includes wells in both the Pinedale and Jonah fields.

Pennsylvania

	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	16.0	8.0	1.0	0.4	—	—
Dry	—	—	—	—	—	—
Total	16.0	8.0	1.0	0.4	—	—

At year end, there were 1 gross (0.5 net) additional development wells that were either drilling or had operations suspended.

	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive	48.0	18.9	184.0	86.7	171.0	99.0
Dry	—	—	—	—	—	—
Total	48.0	18.9	184.0	86.7	171.0	99.0

At year end, there was 1 gross (0.5 net) additional exploratory well that was either drilling or had operations suspended.

Colorado

	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive	—	—	—	—	—	—
Dry	3.0	3.0	—	—	—	—
Total	3.0	3.0	—	—	—	—

At year end, there were no additional exploratory wells that were either drilling or had operations suspended.

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 or predict 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. ***Mine Safety Disclosures.***

None.

PART II

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

The Company's common shares trade on the New York Stock Exchange ("NYSE") under the symbol "UPL". The following table sets forth the high and low intra-day sales prices of the common shares for the periods indicated.

The following share price performance graph is intended to allow review of shareholder returns, expressed in terms of the appreciation of the Company's common shares relative to two broad-based stock performance indices. The information is included for historical comparative purposes only and should not be considered indicative of future share performance. The graph compares the yearly percentage change in the cumulative total shareholder return on the Company's common shares with the cumulative total return of the NYSE Composite Index and of the Dow Jones U.S. Exploration and Production TSM Index from December 31, 2007 through December 31, 2012.

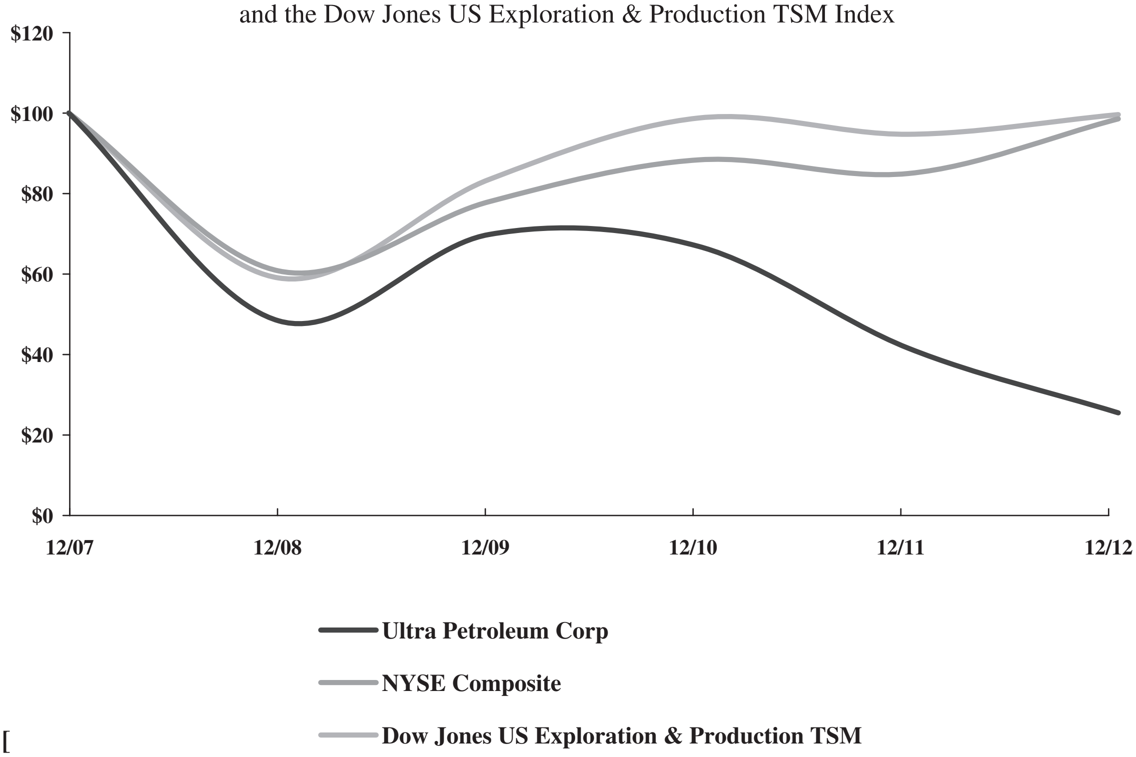
2012	High	Low
1st quarter	$30.66	$22.03
2nd quarter	$23.43	$17.62
3rd quarter	$24.52	$19.96
4th quarter	$24.26	$17.58

2011	High	Low
1st quarter	$50.97	$41.83
2nd quarter	$51.20	$42.90
3rd quarter	$47.89	$27.56
4th quarter	$36.72	$24.39

As of February 15, 2013, the last reported sales price of the common shares on the NYSE was $16.00 per share and there were approximately 340 holders of record of the common shares.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among Ultra Petroleum Corp, the NYSE Composite Index, and the Dow Jones US Exploration & Production TSM Index



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* $100 invested on 12/31/07 in stock or index, including reinvestment of dividentds. Fiscal year ending December 31.

	12/07	12/08	12/09	12/10	12/11	12/12
Ultra Petroleum Corp	**100.00**	**48.27**	**69.73**	**66.81**	**41.44**	**25.36**
NYSE Composite	**100.00**	**60.74**	**77.92**	**88.36**	**84.96**	**98.55**
Dow Jones US Exploration & Production TSM	**100.00**	**58.97**	**83.46**	**98.81**	**94.76**	**99.66**

The stock price performance included in this graph is not necessarily indicative of future stock price performance.

The Company has not declared or paid and does not anticipate declaring or paying any dividends on its common shares in the near future. The Company intends to retain its cash flow from operations for the future operation and development of its business.

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 shares which has been and will be funded by cash on hand and the Company's senior credit facility.

Period	Total Number of Shares Repurchased (000's)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (000's)	Maximum Number (or Approximate Dollar Value) of Shares That May Yet be Purchased Under the Plans or Programs
November 2012	5	$23.10	5	$385.4 million

Item 6. *Selected Financial Data.*

The selected consolidated financial information presented below for the years ended December 31, 2012, 2011, 2010, 2009 and 2008 is derived from the Consolidated Financial Statements of the Company.

	Year Ended December 31,				
	2012	2011	2010	2009	2008
	(In thousands, except per share data)				
Statement of Operations Data:					
Revenues:					
Natural gas sales	$ 695,733	$ 982,413	$ 886,396	$ 601,023	$ 986,374
Oil sales	114,241	119,383	92,990	65,739	98,026
Total operating revenues	809,974	1,101,796	979,386	666,762	1,084,400
Expenses:					
Production expenses and taxes	184,229	205,363	191,978	152,804	194,243
Transportation charges	84,470	64,243	64,965	58,011	46,310
Depletion, depreciation and amortization	388,985	346,394	241,796	201,826	184,795
Ceiling test and other impairments	2,972,464	—	—	1,037,000	—
General and administrative	14,348	12,113	11,407	8,871	11,230
Stock compensation	10,756	13,919	12,944	10,901	5,816
Interest expense	88,180	63,156	49,032	37,167	21,276
Total operating expenses	3,743,432	705,188	572,122	1,506,580	463,670
Other:					
Gain on commodity derivatives	73,581	313,732	325,452	146,517	33,216
Contract cancellation fees	(15,469)	—	—	—	—
Litigation expense	—	—	(9,902)	—	—
Other income (expense) , net	(1,765)	532	260	(2,888)	833
Total other (expense) income, net	56,347	314,264	315,810	143,629	34,049
(Loss) income before income taxes	(2,877,111)	710,872	723,074	(696,189)	654,779
Income tax (benefit) provision	(700,213)	257,670	258,615	(245,136)	240,504
Net (loss) income	$(2,176,898)	$ 453,202	$ 464,459	$ (451,053)	$ 414,275
Basic (Loss) Earnings per Share:					
Net (loss) income per common share — basic	$ (14.24)	$ 2.97	$ 3.05	$ (2.98)	$ 2.72
Fully (Loss) Diluted Earnings per Share:					
Net (loss) income per common share — fully diluted	$ (14.24)	$ 2.94	$ 3.01	$ (2.98)	$ 2.65
Statement of Cash Flows Data:					
Net cash provided by (used in):					
Operating activities	$ 654,825	$ 1,033,292	$ 824,728	$ 592,641	$ 840,803
Investing activities	$ (577,223)	$(1,408,795)	$(1,529,099)	$ (820,611)	$ (915,319)
Financing activities	$ (75,988)	$ 315,976	$ 760,951	$ 228,067	$ 78,041
Balance Sheet Data:					
Cash and cash equivalents	$ 12,921	$ 11,307	$ 70,834	$ 14,254	$ 14,157
Working capital (deficit)	$ (388,244)	$ (251,059)	$ (56,967)	$ (137,450)	$ (149,355)
Oil and gas properties	$ 1,657,499	$ 4,189,148	$ 3,075,670	$1,794,603	$2,350,526
Total assets	$ 2,007,345	$ 4,869,705	$ 3,595,615	$2,060,005	$2,558,162
Total long-term debt	$ 1,837,000	$ 1,903,000	$ 1,560,000	$ 795,000	$ 570,000
Other long-term obligations	$ 76,038	$ 67,008	$ 52,575	$ 35,858	$ 46,206
Deferred income taxes, net	$ —	$ 635,009	$ 420,711	$ 239,217	$ 503,597
Total shareholders' (deficit) equity	$ (577,867)	$ 1,593,709	$ 1,138,976	$ 648,197	$1,090,786

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, which are included in this report in Item 8, and the information set forth in Risk Factors under Item 1A. Except as otherwise indicated, all amounts are expressed in U.S. dollars.

Overview

Ultra Petroleum Corp. is an independent exploration and production company focused on developing its long-life natural gas reserves in the Green River Basin of Wyoming—the Pinedale and Jonah fields—and is in the early exploration and development stages in the Appalachian Basin of Pennsylvania. The Company operates in one industry segment, natural gas and oil exploration and development, with one geographical segment, the United States.

The Company currently conducts operations exclusively in the United States. Substantially all of its 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. The Company continues to focus on improving its drilling and production results through gaining efficiencies with the use of advanced technologies, detailed technical analysis of its properties and leveraging its experience into improved operational efficiencies. Inflation is not expected to have a material impact on the Company's results of operations in the future.

The Company currently generates its revenue, earnings and cash flow primarily from the production and sales of natural gas and condensate from its properties in southwest Wyoming with an increasing portion of the Company's revenues coming from gas sales from wells located in the Appalachian Basin in Pennsylvania.

Part of the Company's business strategy includes proactive and regular review of its portfolio of investment opportunities with a focus on investments that produce positive returns. Accordingly, in response to the current low natural gas price environment during 2012, the Company reduced its net capital investments from $1.5 billion in 2011 to $615.2 million in 2012 by releasing all but two of its operated drilling rigs in Wyoming and reducing drilling activity in Pennsylvania.

The price of natural gas is a critical factor to the Company's business and the price of natural gas has declined significantly since the beginning of 2011. During 2012, the Company limited the impact of these low prices on its results by entering into swap agreements and/or fixed price forward physical delivery contracts for natural gas. The average price realization for the Company's natural gas during 2012 was $4.01 per Mcf, including realized gains and losses on commodity derivatives. During the quarter ended December 31, 2012, the average price realization for the Company's natural gas was $4.08 per Mcf, including realized gains and losses on commodity derivatives. The Company's average price realization for natural gas, excluding realized gains and losses on commodity derivatives, was $2.79 per Mcf and $3.33 per Mcf for the year and quarter ended December 31, 2012, respectively. Because of the Company's belief that overall domestic natural gas supply will decline and natural gas forward prices will increase in response, the Company has not hedged any of its forecast 2013 natural gas production. (See Note 7).

Mission and Strategy

Ultra's mission is to profitably grow an upstream oil and gas company for the long-term benefit of its shareholders. Ultra's strategy includes building a robust portfolio of high return investment opportunities, maintaining a disciplined approach to capital investment, maximizing earnings and cash flows by controlling costs and maintaining financial flexibility. Consistent with this mission and strategy, the Company significantly reduced its activity during 2012 as a result of the low prevailing natural gas prices during 2012. As a result of this reduced activity, the number of wells drilled and completed by the Company was lower in 2012 than in some prior years. In addition, as a result of the low gas prices, the Company was required to record a $2.9 billion non-cash, ceiling test write-down of the carrying value of its oil and gas properties, and the Company's proved reserves were reduced to 3.08 Tcfe at December 31, 2012 from 4.98 Tcfe at December 31, 2011. For additional information about steps the Company is taking to address low natural gas prices, see the "Marketing and Pricing" section of Item 1. Business.

Because dry natural gas drilling activities were significantly reduced by most oil and gas operators during 2012, the Company expects natural gas supply to decline. As a result, the Company believes the current low natural gas prices are unsustainable, and the Company expects natural gas prices to improve over the next two years. If natural gas prices recover as the Company expects, the Company should be able to restore its proved undeveloped reserves to at least prior prevailing levels. The reduction in proved reserves reflected in the year-end 2012 report is not the result of any change in the geologic prospectivity of the Company's properties.

As required by SEC regulations, the Company used a calculated weighted average natural gas sales price of $2.63 per Mcf and $4.04 per Mcf for estimating its proved reserves at December 31, 2012 and 2011, respectively. The lower gas price for the 2012 reserves negatively impacted the Company in two ways. First, some of its 2011 proved reserves are uneconomic at the 2012 SEC gas price. Second, some of its 2011 proved undeveloped reserves were reclassified as unproven properties in 2012 because the 2012 SEC gas price reduced capital available for the Company to drill its proved undeveloped properties.

High Return Portfolio. Ultra seeks to maintain a portfolio of properties that provide long-term, profitable growth through development in areas that support sustainable, lower-risk, repeatable, high return drilling projects. The Company continually evaluates opportunities for the acquisition, exploration and development of additional oil and natural gas properties that afford risk-adjusted returns in excess of or equal to its current set of investment alternatives.

Disciplined Capital Investment. Part of the Company's business strategy includes proactive and regular review of its portfolio of investment opportunities with a focus on investments that produce positive returns in order to optimize return to its shareholders. Accordingly, in response to the current low natural gas price environment, the Company reduced capital expenditures by reducing the number of drilling rigs operating in its Wyoming fields, and the Company is encouraging the parties operating projects on its behalf in Pennsylvania to reduce their activity as well. Reductions in the Company's activity resulted in reduced capital spending during the current year as compared to the prior year.

Low Cost Producer. Ultra strives to maintain one of the lowest cost structures in the industry in terms of both adding and producing oil and natural gas reserves. The Company continues to focus on improving its drilling and production results through the use of advanced technologies and detailed technical analysis of its properties.

Financial Flexibility. Preserving financial flexibility and a strong balance sheet are also strategic to Ultra's business philosophy. Maintaining financial discipline enables the Company to capitalize on the flexibility of its portfolio.

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. 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 related to 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.

Oil and Gas Reserves. The reserve estimates presented herein were made in accordance with oil and gas reserve estimation and disclosure authoritative accounting guidance according to Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 932, Extractive Activities – Oil and Gas ("FASB ASC 932") as updated in order to align the reserve calculation and disclosure requirements with those in SEC Release No. 33-8995.

The Company utilizes reliable technology such as seismic data and interpretation, wireline formation tests, geophysical logs and core data to assess its resources. However, none of these technologies have contributed to a material addition to the proved reserves in this report. The proved reserves estimates are prepared by Netherland, Sewell & Associates, Inc., an independent, third-party engineering firm.

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 a number of factors including lower prices, evaluation of additional operating history, mechanical problems on our wells and catastrophic events. Lower prices also make it uneconomical to drill wells or produce from fields with high operating costs.

The Company's proved reserves are a function of many assumptions, all of which could deviate materially from actual results. As a result, the estimates of proved reserves could vary over time, and could vary from actual results.

Full Cost Method of Accounting. The Company uses the full cost method of accounting for oil and gas exploration and development activities as defined by SEC Release No. 33-8995 and FASB ASC 932. Under the full cost method of accounting, all costs associated with the exploration for and development of oil and gas reserves are capitalized on a country-by-country basis. 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.

Under the full cost method, costs of unevaluated properties and major development projects expected to require significant future costs may be excluded from capitalized costs being amortized. The Company excludes significant costs until proved reserves are found or until it is determined that the costs are impaired. Excluded costs, if any, are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the capitalized costs being amortized in the appropriate full cost pool.

Write-down of Oil and Gas Properties. 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, utilizing the average of prices in effect on the first day of the month for the preceding twelve month period. 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 a lower DD&A rate 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 calculation of the ceiling test is based upon estimates of proved reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves, in projecting the future rates of production and in the timing of development activities. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

During 2012, the Company recorded a $2.9 billion non-cash write-down of the carrying value of the Company's proved oil and gas properties as a result of ceiling test limitations, which is reflected with ceiling test and other impairments in the accompanying Consolidated Statements of Operations. The ceiling test was calculated based upon the average of quoted market prices in effect on the first day of the month for the preceding twelve month period at December 31, 2012, September 30, 2012 and June 30, 2012 of $2.76 per MMBtu, $2.83 per MMBtu and $3.15 per MMBtu for Henry Hub natural gas, respectively, and $94.71 per barrel, $94.97 per barrel and $95.67 per barrel for West Texas Intermediate oil, respectively, adjusted for market differentials. The Company did not have any write-downs related to the full cost ceiling limitation in 2011 or 2010.

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. FASB ASC Topic 410, Asset Retirement and Environmental Obligations ("FASB ASC 410") 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 costs, including revisions thereto, are charged to expense through DD&A.

Entitlements Method of Accounting for Oil and Natural Gas Sales. The Company generally sells natural gas and condensate 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 collectability 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 a result of the tax effect of the ceiling test and other impairments recorded during the year ended December 31, 2012, the Company's previously recorded net deferred tax liability fully reversed into a net deferred tax asset. The Company has recorded a full valuation allowance against its net deferred tax asset balance of $449.8 million as of December 31, 2012. This valuation allowance may be reversed in future periods against future taxable income.

Derivative Instruments and Hedging Activities. The Company follows FASB ASC Topic 815, Derivatives and Hedging ("FASB ASC 815"). The Company records the fair value of its commodity derivatives as an asset or liability on the Consolidated Balance Sheets, and records the changes in the fair value of its commodity derivatives in the Consolidated Statements of Operations as an unrealized gain or loss on commodity derivatives.

Fair Value Measurements. The Company follows FASB ASC Topic 820, Fair Value Measurements and Disclosures ("FASB ASC 820"). Under FASB ASC 820, fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at measurement date and establishes a three level hierarchy for measuring fair value. The valuation assumptions the Company has used to measure the fair value of its commodity derivatives were observable inputs based on market data obtained from independent sources and are considered Level 2 inputs (quoted prices for similar assets, liabilities (adjusted) and market-corroborated inputs). At December 31, 2012, the Company did not have any open commodity derivative contracts. See Note 8 for additional information.

In consideration of counterparty credit risk, the Company assessed the possibility of whether each counterparty to the derivative would default by failing to make any contractually required payments as scheduled in the derivative instrument in determining the fair value. Additionally, the Company considers that it is of substantial credit quality and has the financial resources and willingness to meet its potential repayment obligations associated with the derivative transactions.

The Company recognized impairments of $92.5 million during the year ended December 31, 2012 related to the decline in fair value as defined in FASB ASC 820 as a result of forecast decreased throughput volumes on its gathering facilities in Pennsylvania due to the decline in commodity prices. These facilities are included in Property, Plant and Equipment in the Consolidated Balance Sheets and were impaired to a fair value of $82.6 million based on the income approach, estimated using Level 3 fair value inputs.

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. The Company follows FASB ASC Topic 718, Compensation – Stock Compensation ("FASB ASC 718") 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. Share-based compensation expense recognized under FASB ASC 718 for the years ended December 31, 2012, 2011 and 2010 was $10.8 million, $13.9 million and $12.9 million, respectively. See Note 6 for additional information.

Conversion of Barrels of Oil to Mcfe of Gas. The Company converts Bbls of oil and other liquid hydrocarbons to Mcfe at a ratio of one Bbl of oil or liquids to six Mcfe. This conversion ratio, which is typically used in the oil and gas industry, represents the approximate energy equivalent of a barrel of oil or other liquids to an Mcf of natural gas. The sales price of one Bbl of oil or liquids has been much higher than the sales price of six Mcf of natural gas over the last several years, so a six to one conversion ratio does not represent the economic equivalency of six Mcf of natural gas to a Bbl of oil or other liquids.

Recent Accounting Pronouncements. In May 2011, the FASB issued ASU No. 2011-04, which amends FASB ASC 820. The amended guidance clarifies many requirements in U.S. GAAP for measuring fair value and for disclosing information about fair value measurements. Additionally, the amendments clarify the FASB's intent about the application of existing fair value measurement requirements. The guidance provided in ASU No. 2011-04 is effective for interim and annual periods beginning after December 15, 2011. The adoption of this amendment did not have a material impact on the Company's consolidated financial statements.

Results of Operations — Year Ended December 31, 2012 vs. Year Ended December 31, 2011

During the year ended December 31, 2012, production increased on a gas equivalent basis to 257.0 Bcfe from 245.3 Bcfe for the same period in 2011 as a result of wells put on production in 2012. Realized natural gas prices, including realized gain and loss on commodity derivatives, decreased to $4.01 per Mcf during the year ended December 31, 2012 as compared to $5.05 per Mcf during 2011. During the year ended December 31, 2012, the Company's average price for natural gas was $2.79 per Mcf, excluding realized gains and losses on commodity derivatives as compared to $4.15 per Mcf for the same period in 2011. The decrease in average natural gas prices largely contributed to a 26% decrease in revenues for the year ended December 31, 2012 to $810.0 million as compared to $1.1 billion in 2011.

Lease operating expenses ("LOE") increased to $64.5 million for the year ended December 31, 2012 compared to $51.8 million during the same period in 2011 primarily due to increased well counts resulting from the Company's drilling program. On a unit of production basis, LOE costs increased to $0.25 per Mcfe at December 31, 2012 compared to $0.21 per Mcfe at December 31, 2011 as a result of higher lease operating expense on non-operated wells in Pennsylvania.

During the year ended December 31, 2012, production taxes were $60.8 million compared to $97.1 million during the same period in 2011, or $0.24 per Mcfe, compared to $0.40 per Mcfe. Production taxes are primarily calculated based on a percentage of revenue from production in Wyoming after certain deductions and were 7.5% of revenues for the year ended 2012 and 8.8% for the same period in 2011. In addition, the year ended December 31, 2012 includes charges related to Pennsylvania impact fees totaling $5.6 million while the period ended December 31, 2011 did not include any charges related to impact fees in Pennsylvania. The decrease in per unit taxes is primarily attributable to decreased sales revenues as a result of decreased natural gas prices, excluding the effects of commodity derivatives, during the year December 31, 2012 as compared to the same period in 2011.

Gathering fees increased to $59.0 million for the year ended December 31, 2012 compared to $56.5 million during the same period in 2011 largely due to increased production volumes. On a per unit basis, gathering fees remained flat at $0.23 per Mcfe for the year ended December 31, 2012 and 2011.

The Company incurred firm transportation charges totaling $84.5 million for the period ended December 31, 2012 as compared to $64.2 million for the same period in 2011 in association with REX pipeline charges. On a per unit basis, transportation charges increased to $0.33 per Mcfe (on total company volumes) for the period ended December 31, 2012 as compared to $0.26 for the same period in 2011 primarily due to demand charges associated with the additional capacity of 50 MMMBtu per day secured on the REX pipeline system beginning in January 2012.

DD&A expenses increased to $389.0 million during the period ended December 31, 2012 from $346.4 million for the same period in 2011, attributable primarily to increased production volumes and a higher depletion rate. On a unit of production basis, DD&A increased to $1.51 per Mcfe at December 31, 2012 from $1.41 at December 31, 2011 primarily as a result of increased costs in Pennsylvania.

The Company recorded a $2.9 billion non-cash write-down of the carrying value of its proved oil and natural gas properties for the period ended December 31, 2012 as a result of ceiling test limitations, which is reflected as ceiling test and other impairments in the accompanying Consolidated Statements of Operations. The ceiling test was calculated based upon the average of quoted market prices in effect on the first day of the month for the preceding twelve month period at December 31, 2012, September 30, 2012 and June 30, 2012 of $2.76 per MMBtu, $2.83 per MMBtu and $3.15 per MMBtu for Henry Hub natural gas, respectively, and $94.71 per barrel, $94.97 per barrel and $95.67 per barrel for West Texas Intermediate oil, respectively, adjusted for market differentials. The write-down reduced earnings in the period and will result in a lower DD&A rate in future periods. The Company did not have any write-downs related to the full cost ceiling limitation during the prior year period ended December 31, 2011. See Note 1(e). In addition, the Company recognized impairments of $92.5 million during the year ended December 31, 2012 related to the decline in fair value as defined in FASB ASC 820 as a result of forecast decreased throughput volumes on its gathering facilities in Pennsylvania due to the decline in commodity prices. These assets are included in Property, Plant and Equipment in the Consolidated Balance Sheets. (See Note 8 for additional information on fair value).

General and administrative expenses decreased slightly to $25.1 million for the period ended December 31, 2012 compared to $26.0 million for the same period in 2011. On a per unit basis, general and administrative expenses decreased to $0.10 per Mcfe for the year ended December 31, 2012 compared with $0.11 per Mcfe in 2011 as a result of increased production volumes during 2012.

Interest expense increased to $88.2 million during the period ended December 31, 2012 compared to $63.2 million during the same period in 2011 primarily as a result of higher average borrowings outstanding during the year ended December 31, 2012 and lower amounts of capitalized interest related to unevaluated oil and gas properties that are excluded from amortization. For the years ended December 31, 2012 and 2011, the Company capitalized $15.0 million and $30.7 million, respectively, in interest associated with unevaluated oil and gas properties that are excluded from amortization and actively being evaluated as well as work in process relating to gathering systems that are not currently in service. At December 31, 2012, all costs related to unevaluated properties that were previously excluded from capitalized costs being amortized have been impaired and transferred to the capitalized costs being amortized in the full cost pool.

During the year ended December 31, 2012, the Company recognized contract cancellation expenses of $15.5 million. In response to low natural gas prices, the Company reduced its drilling rig count to two operated rigs, down from six at December 31, 2011.

During the year ended December 31, 2012, the Company recognized $304.0 million related to realized gain on commodity derivatives as compared to $213.3 million during the year ended December 31, 2011. The realized gain or loss on commodity derivatives relates to actual amounts received or paid under the Company's derivative contracts.

At December 31, 2012, the Company recognized $230.4 million related to unrealized loss on commodity derivatives as compared to $100.4 million related to unrealized gain on commodity derivatives at December 31, 2011. The unrealized gain or loss on commodity derivatives represents the non-cash change in the fair value of these derivative instruments.

The Company recognized a loss before income taxes of $2.9 billion for the year ended December 31, 2012 compared with income before income taxes of $710.9 million for the same period in 2011. The decrease in earnings is primarily related to the non-cash ceiling test and other impairments and decreased natural gas prices partially offset by increased production during 2012.

As a result of the tax effect of the non-cash ceiling test and other impairments, the Company's previously recorded net deferred tax liability fully reversed into a net deferred tax asset during the quarter ended June 30, 2012. The Company has recorded a full valuation allowance against its net deferred tax asset balance of $449.8 million as of December 31, 2012. This valuation allowance may be reversed in future periods against future taxable income. The income tax benefit recognized for the year ended December 31, 2012 was $700.2 million compared with an income tax provision of $257.7 million for the year ended December 31, 2011.

For the year ended December 31, 2012, the Company recognized net loss of $2.2 billion or ($14.24) per diluted share as compared with net income of $453.2 million or $2.94 per diluted share for the same period in 2011. The decrease in earnings is primarily related to the non-cash ceiling test and other impairments and decreased natural gas prices partially offset by increased production during 2012.

Results of Operations — Year Ended December 31, 2011 vs. Year Ended December 31, 2010

During the year ended December 31, 2011, production increased on a gas equivalent basis to 245.3 Bcfe from 213.6 Bcfe for the same period in 2010 attributable to the Company's successful drilling activities during 2011. Realized natural gas prices, including realized gain and loss on commodity derivatives, increased to $5.05 per Mcf during the year ended December 31, 2011 as compared to $4.88 per Mcf during 2010. During the year ended December 31, 2011, the Company's average price for natural gas was $4.15 per Mcf, excluding realized gains and losses on commodity derivatives as compared to $4.31 per Mcf for the same period in 2010. The increase in production largely contributed to a 12% increase in revenues for the year ended December 31, 2011 to $1.1 billion as compared to $979.4 million in 2010.

Lease operating expenses ("LOE") increased to $51.8 million for the year ended December 31, 2011 compared to $45.9 million during the same period in 2010 due primarily to increased well counts resulting from the Company's drilling program. On a unit of production basis, LOE costs decreased to $0.21 per Mcfe at December 31, 2011 compared to $0.22 per Mcfe at December 31, 2010 as a result of increased production volumes.

During the year ended December 31, 2011, production taxes were $97.1 million compared to $95.9 million during the same period in 2010, or $0.40 per Mcfe, compared to $0.45 per Mcfe. Production taxes are calculated based on a percentage of revenue from production in Wyoming after certain deductions and were 8.8% of revenues for the year ended 2011 and 9.8% for the same period in 2010. The decrease in per unit taxes is primarily attributable to increased production in Pennsylvania, which is not subject to production taxes, as well as the decrease in average natural gas prices, excluding the effects of commodity derivatives, during the year ended December 31, 2011 as compared to the same period in 2010.

Gathering fees increased to $56.5 million for the year ended December 31, 2011 compared to $50.1 million during the same period in 2010 largely due to increased production volumes. On a per unit basis, gathering fees remained flat at $0.23 per Mcfe for the years ended December 31, 2011 and 2010.

To secure pipeline infrastructure providing sufficient capacity to transport a portion of the Company's natural gas production away from southwest Wyoming and to provide for reasonable basis differentials for its natural gas, the Company incurred firm transportation charges totaling $64.2 million for the period ended December 31, 2011 as compared to $65.0 million for the same period in 2010 in association with REX Pipeline transportation charges. On a per unit basis, transportation charges decreased to $0.26 per Mcfe (on total company volumes) for the period ended December 31, 2011 as compared to $0.30 for the same period in 2010 due to the increase in total company production volumes during the period ended December 31, 2011.

DD&A increased to $346.4 million during the period ended December 31, 2011 from $241.8 million for the same period in 2010, attributable to increased production volumes and a higher depletion rate. On a unit of production basis, DD&A increased to $1.41 per Mcfe at December 31, 2011 from $1.13 at December 31, 2010 largely as a result of increased well costs in Pennsylvania.

General and administrative expenses increased to $26.0 million for the period ended December 31, 2011 compared to $24.4 million for the same period in 2010. The increase in general and administrative expenses is primarily attributable to increased headcount and related compensation. On a per unit basis, general and administrative expenses remained flat at $0.11 per Mcfe for the years ended December 31, 2011 and 2010.

Interest expense increased to $63.2 million during the period ended December 31, 2011 compared to $49.0 million during the same period in 2010 as a result of increased borrowings outstanding during the period ended December 31, 2011. For the years ended December 31, 2011 and 2010, the Company capitalized $30.7 million and $21.2 million, respectively, in interest associated with unevaluated oil and gas properties that are excluded from amortization and actively being evaluated as well as work in process relating to gathering systems that are not currently in service. At December 31, 2011, the Company had $1.9 billion in borrowings outstanding.

During the year ended December 31, 2010, the Company recognized litigation expenses of $9.9 million related to the resolution of litigation matters.

During the year ended December 31, 2011, the Company recognized $213.3 million related to realized gain on commodity derivatives as compared to $116.8 million during the year ended December 31, 2010. The realized gain or loss on commodity derivatives relates to actual amounts received or paid under the Company's derivative contracts.

At December 31, 2011, the Company recognized $100.4 million related to unrealized gain on commodity derivatives as compared to $208.6 million related to unrealized gain on commodity derivatives at December 31, 2010. The unrealized gain or loss on commodity derivatives represents the non-cash change in the fair value of these derivative instruments.

The Company recognized income before income taxes of $710.9 million for the year ended December 31, 2011 compared with $723.1 million for the same period in 2010. The decrease in earnings is primarily a result of increased DD&A expense during 2011 and partially offset by increased revenues during 2011.

The income tax provision recognized for the year ended December 31, 2011 was $257.7 million compared with an income tax provision of $258.6 million for the year ended December 31, 2010.

For the year ended December 31, 2011, the Company recognized net income of $453.2 million or $2.94 per diluted share as compared with net income of $464.5 million or $3.01 per diluted share for the same period in 2010. The decrease is primarily attributable to increased DD&A expense during 2011 and partially offset by increased revenues during 2011.

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. GAAP. In addition, application of generally accepted accounting principles 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.

LIQUIDITY AND CAPITAL RESOURCES

During the year ended December 31, 2012, the Company relied on cash provided by operations along with borrowings under the Credit Agreement (defined below) to finance its capital expenditures. The Company participated in 178 wells that were drilled to total depth and cased during 2012. For the year ended December 31, 2012, total capital expenditures were $839.4 million ($708.0 million related to oil and gas exploration and development expenditures, $127.1 million related to gathering system expenditures and $4.3 million related to other property costs). During December 2012, the Company entered into a Purchase and Sale Agreement (the

"PSA") to sell its system of pipelines and central gathering facilities (the "LGS") and certain associated real property rights in the Pinedale Anticline in Wyoming. The net cash proceeds received for the assets were $203.0 million and additional consideration of $23.0 million in the form of marketable securities which were sold during December 2012 for net cash proceeds of $21.2 million. The proceeds from the sale of the Company's LGS were used to repay amounts outstanding under the Company's Credit Agreement (defined below).

At December 31, 2012, the Company reported a cash position of $12.9 million compared to $11.3 million at December 31, 2011. Working capital deficit at December 31, 2012 was $388.2 million compared to a deficit of $251.1 million at December 31, 2011. At December 31, 2012, the Company had $277.0 million in outstanding borrowings and $723.0 million of available borrowing capacity under the Credit Agreement (defined below). In addition, the Company had $1.6 billion outstanding in senior notes (See Note 5). Other long-term obligations of $76.0 million at December 31, 2012 is comprised of items payable in more than one year, primarily related to production taxes and asset retirement obligations.

The Company's positive cash provided by operating activities, along with availability under the senior credit facility, are projected to be sufficient to fund the Company's budgeted capital investment program for 2013, which is currently projected to be approximately $415.0 million. Of the $415.0 million budget, the Company plans to allocate approximately 90% to exploration and development related expenditures and the remainder to gathering and infrastructure and other.

Bank indebtedness. The Company (through its subsidiary, Ultra Resources, Inc.) is a party to a revolving credit facility with a syndicate of banks led by JP Morgan Chase Bank, N.A. (the "Credit Agreement"). The Credit Agreement provides an initial loan commitment of $1.0 billion, which may be increased up to $1.25 billion at the request of the borrower and with the lenders' consent, provides for the issuance of letters of credit of up to $250.0 million in aggregate, and matures in October 2016 (which term may be extended for up to two successive one-year periods at the Borrower's request and with the lenders' consent). At December 31, 2012, the Company had $277.0 million in outstanding borrowings and $723.0 million of available borrowing capacity under the Credit Agreement.

Loans under the Credit Agreement are unsecured and bear interest, at the Borrower's option, based on (A) a rate per annum equal to the prime rate or the weighted average fed funds rate on overnight transactions during the preceding business day plus 100 basis points, or (B) a base Eurodollar rate, substantially equal to the LIBOR rate, plus a margin based on a grid of the Borrower's consolidated leverage ratio (200 basis points per annum as of December 31, 2012). The Company also pays commitment fees on the unused commitment under the facility based on a grid of its consolidated leverage ratio.

The Credit Agreement contains typical and customary representations, warranties, covenants and events of default. The Credit Agreement includes restrictive covenants requiring the Borrower to maintain a consolidated leverage ratio of no greater than three and one half times to one and, as long as the Company's debt rating is below investment grade, the maintenance of an annual ratio of the net present value of the Company's oil and gas properties to total funded debt of no less than one and one half times to one. At December 31, 2012, the Company was in compliance with all of its debt covenants under the Credit Agreement. (See Note 5).

Senior Notes: The Company's Senior Notes rank pari passu with the Company's Credit Agreement. Payment of the Senior Notes is guaranteed by Ultra Petroleum Corp. and UP Energy Corporation. The Senior Notes are pre-payable in whole or in part at any time and are subject to representations, warranties, covenants and events of default customary for a senior note financing. At December 31, 2012, the Company was in compliance with all of its debt covenants under the Senior Notes. (See Note 5).

Operating Activities. During the year ended December 31, 2012, net cash provided by operating activities was $654.8 million, a 37% decrease from $1.0 billion for the same period in 2011. The decrease in net cash provided by operating activities was largely attributable to decreased revenues resulting from decreased natural gas prices during the year ended December 31, 2012 as compared to the same period in 2011.

Investing Activities. During the year ended December 31, 2012, net cash used in investing activities was $577.2 million as compared to $1.4 billion for the same period in 2011. The decrease in net cash used in investing activities is largely related to decreased capital investments associated with the Company's drilling activities in 2012 as compared to 2011 and proceeds from the sale of the LGS during December 2012.

Financing Activities. During the year ended December 31, 2012, net cash used in financing activities was $76.0 million as compared to net cash provided by financing activities of $316.0 million for the same period in 2011. The change in cash used in net financing activities is primarily due to decreased borrowings during 2012 as compared to 2011.

Outlook

We believe we are well positioned for the current economic environment because of our status as a low cost operator in the industry combined with our financial flexibility. In 2012, the Company established new production records while maintaining a low cost structure. The Company's low cost structure contributes to the Company's long-term favorable returns and growth profile.

Although our net cash provided by operating activities was negatively affected by continued low natural gas prices, and although we have not hedged any of our 2013 production because we expect natural gas prices to improve over the next two years, we believe that we will continue to generate positive cash flow from operations, which, along with our available cash, will provide sufficient liquidity to fund our capital investments and operations over the next twelve months. We continue to monitor and evaluate the impact of reduced commodity prices in order to determine the appropriate size and nature of our capital investment program.

We expect to rely on our available cash, our existing credit facility and the cash generated from operations to meet our obligations. While we continue to monitor the overall health of the credit markets, a renewed, long-term disruption in the credit markets could make financing more expensive or unavailable, which could have a material adverse effect on our operations.

OFF BALANCE SHEET ARRANGEMENTS

The Company did not have any off-balance sheet arrangements as of December 31, 2012.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2012:

	Payments Due by period:				
	Total	Less than 1 year	1 to 3 years	3 to 5 years	More than 5 years
	(Amounts in thousands of U.S. dollars)				
Long-term debt (See Note 5)	$1,837,000	$ —	$100,000	$455,000	$1,282,000
Interest payments	644,319	93,918	183,267	154,745	212,389
Transportation contract (REX)(1)	673,027	103,295	201,845	202,122	165,765
Operating lease	299,397	20,000	40,000	40,000	199,397
Drilling contracts	21,487	14,973	6,514	—	—
Office space lease	1,540	876	664	—	—
Total contractual obligations	$3,476,770	$233,062	$532,290	$851,867	$1,859,551

(1) The Company's average net interest in payments related to REX transportation charges is approximately 80%.

Transportation contract. The Company is an anchor shipper on REX securing pipeline infrastructure providing sufficient capacity to transport a portion of its natural gas production away from its properties and to provide for reasonable basis differentials for its natural gas in the future. REX begins at the Opal Processing Plant in southwest Wyoming and traverses Wyoming and several other states to an ultimate terminus in eastern Ohio. The Company's commitment involves a capacity of 200 MMMBtu per day of natural gas for a term of 10 years commencing in November 2009. During the first quarter of 2009, the Company entered into agreements to secure an additional capacity of 50 MMMBtu per day on the REX pipeline system, beginning in January 2012 through December 2018. The Company is obligated to pay REX certain demand charges related to its rights to hold this firm transportation capacity as an anchor shipper. The Company has the right, but not the obligation, to deliver its natural gas production into the REX pipeline, but must pay its reservation charges in either event. The Company continuously assesses its best available market options when determining the appropriate level of utilization of its REX capacity.

Operating lease. During December 2012, the Company entered into a Purchase and Sale Agreement (the "LGS PSA") to sell its system of pipelines and central gathering facilities (the "LGS") and certain associated real property rights in the Pinedale Anticline in Wyoming. The net cash proceeds received for the assets were $203.0 million and additional consideration of $23.0 million in the form of marketable securities which were sold during December 2012 for net cash proceeds of $21.2 million.

Pursuant to the LGS PSA, the Company entered into a long-term, triple net lease agreement with the buyer relating to the use of the LGS (the "Lease Agreement"). The Lease Agreement provides for an initial term of 15 years and potential successive renewal terms of 5 years or 75% of the then remaining useful life of the LGS at the sole discretion of the Company. Annual rent for the initial term under the Lease Agreement is $20.0 million (as adjusted annually for changes based on the consumer price index) and may increase if certain volume thresholds are exceeded. The Company's sale leaseback transaction was treated as a "normal leaseback" under the provisions of FASB ASC Topic 840, Leases and qualified for sales recognition. The lease is classified as an operating lease.

All of the Company's lease obligations are related to leases that are classified as operating leases. These leases contain certain provisions that could result in accelerated lease payments. The Company has considered the effect of these provisions on minimum lease payments in its lease classification analysis and has determined that the default provisions do not impact classification of any the Company's operating leases.

Drilling contracts. As of December 31, 2012, the Company had committed to drilling obligations that will continue into 2014. The drilling rigs were contracted to fulfill the 2013-2014 drilling program initiatives in Wyoming.

Office space lease. The Company maintains office space in Colorado, Texas, Wyoming and Pennsylvania with total remaining commitments for office leases of $1.5 million at December 31, 2012 ($0.9 million in 2013 and $0.7 million in 2014 to 2015).

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

Objectives and Strategy: 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.

Historically, the Company has entered into various types of derivative transactions to manage its exposure to commodity price risk and to provide a level of certainty in the Company's forward cash flows supporting the Company's capital investment program. A significant portion of our revenues during 2010, 2011 and 2012 was attributable to these derivative transactions. Because forward natural gas prices for 2013 production were very low during 2012, the Company has not hedged any of its forecast 2013 natural gas production. As a result of the Company not having hedged any of its 2013 production, its earnings and cash flow may be more volatile during 2013 than in prior years.

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 or greater than the spot prices that it would have received otherwise.

Fair Value of Commodity Derivatives: FASB ASC 815 requires that all derivatives be recognized on the balance sheet as either an asset or liability and be measured at fair value. Changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. The Company does not apply hedge accounting to any of its derivative instruments.

Derivative contracts that do not qualify for hedge accounting treatment are recorded as derivative assets and liabilities at fair value on the balance sheet and the associated unrealized gains and losses are recorded as current expense or income in the income statement. Unrealized gains or losses on commodity derivatives represent the non-cash change in the fair value of these derivative instruments and do not impact operating cash flows on the cash flow statement.

The following table summarizes the pre-tax realized and unrealized gains and losses the Company recognized related to its natural gas derivative instruments in the Consolidated Statements of Operations for the years ended December 31, 2012, 2011 and 2010:

	For the Year Ended December 31,		
Natural Gas Commodity Derivatives:	**2012**	**2011**	**2010**
Realized gain on commodity derivatives(1)	$ 303,966	$213,349	$116,827
Unrealized (loss) gain on commodity derivatives(1)	(230,385)	100,383	208,625
Total gain on commodity derivatives	$ 73,581	$313,732	$325,452

(1) Included in gain on commodity derivatives in the Consolidated Statements of Operations.

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, 2012.

The effectiveness of our internal control over financial reporting has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of Ultra Petroleum Corp.

We have audited the accompanying consolidated balance sheets of Ultra Petroleum Corp. as of December 31, 2012 and 2011, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Ultra Petroleum Corp. at December 31, 2012 and 2011, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Ultra Petroleum Corp.'s internal control over financial reporting as of December 31, 2012, 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 20, 2013 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 20, 2013

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of Ultra Petroleum Corp.

We have audited Ultra Petroleum Corp.'s internal control over financial reporting as of December 31, 2012, 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 included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on 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, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, 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, Ultra Petroleum Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Ultra Petroleum Corp. as of December 31, 2012 and 2011, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2012 of Ultra Petroleum Corp. and our report dated February 20, 2013 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 20, 2013

ULTRA PETROLEUM CORP.

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2012	2011	2010
	(Amounts in thousands of U.S. dollars, except per share data)		
Revenues:			
Natural gas sales	$ 695,733	$ 982,413	$886,396
Oil sales	114,241	119,383	92,990
Total operating revenues	809,974	1,101,796	979,386
Expenses:			
Lease operating expenses	64,468	51,758	45,938
Production taxes	60,757	97,094	95,914
Gathering fees	59,004	56,511	50,126
Transportation charges	84,470	64,243	64,965
Depletion, depreciation and amortization	388,985	346,394	241,796
Ceiling test and other impairments	2,972,464	—	—
General and administrative	25,104	26,032	24,351
Total operating expenses	3,655,252	642,032	523,090
Operating (loss) income	(2,845,278)	459,764	456,296
Other income (expense), net:			
Interest expense	(88,180)	(63,156)	(49,032)
Gain on commodity derivatives	73,581	313,732	325,452
Contract cancellation fees	(15,469)	—	—
Litigation expense	—	—	(9,902)
Other (expense) income, net	(1,765)	532	260
Total other (expense) income, net	(31,833)	251,108	266,778
(Loss) income before income tax (benefit) provision	(2,877,111)	710,872	723,074
Income tax (benefit) provision	(700,213)	257,670	258,615
Net (loss) income	$(2,176,898)	$ 453,202	$464,459
Basic (Loss) Earnings per Share:			
Net (loss) income per common share — basic	$ (14.24)	$ 2.97	$ 3.05
Fully Diluted (Loss) Earnings per Share:			
Net (loss) income per common share — fully diluted	$ (14.24)	$ 2.94	$ 3.01
Weighted average common shares outstanding — basic	152,845	152,754	152,346
Weighted average common shares outstanding — fully diluted	152,845	154,336	154,253

Approved on behalf of the Board:

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

See accompanying notes to consolidated financial statements.

ULTRA PETROLEUM CORP.

CONSOLIDATED BALANCE SHEETS

	December 31, 2012	December 31, 2011
	(Amounts in thousands of U. S. dollars, except share data)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 12,921	$ 11,307
Restricted cash	121	121
Oil and gas revenue receivable	81,143	88,243
Joint interest billing and other receivables	26,712	82,370
Derivative assets	—	230,385
Prepaid drilling costs and other current assets	4,951	7,494
Total current assets	125,848	419,920
Oil and gas properties, net, using the full cost method of accounting:		
Proven	1,657,500	3,651,622
Unproven properties not being amortized	—	537,526
Property, plant and equipment	212,372	246,586
Deferred financing costs and other	11,625	14,051
Total assets	$ 2,007,345	$4,869,705
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 67,489	$ 105,453
Accrued liabilities	121,124	190,420
Production taxes payable	47,745	62,117
Interest payable	30,093	30,306
Deferred tax liabilities	—	73,380
Capital cost accrual	247,641	209,303
Total current liabilities	514,092	670,979
Long-term debt	1,837,000	1,903,000
Deferred income tax liabilities	—	635,009
Deferred gain on sale of liquids gathering system	158,082	—
Other long-term obligations	76,038	67,008
Commitments and contingencies (Note 11)		
Shareholders' equity:		
Common stock — no par value; authorized — unlimited; issued and outstanding — 152,929,907 and 152,476,564, at December 31, 2012 and 2011, respectively	474,016	463,221
Treasury stock	(13)	(14,951)
Retained (loss) earnings	(1,051,870)	1,145,439
Total shareholders' (deficit) equity	(577,867)	1,593,709
Total liabilities and shareholders' equity	$ 2,007,345	$4,869,705

See accompanying notes to consolidated financial statements.

ULTRA PETROLEUM CORP.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

(Amounts in thousands of U.S. dollars, except share data)

	Shares Issued and Outstanding	Common Stock	Retained Earnings	Treasury Stock	Total Shareholders' Equity
Balances at December 31, 2009	151,759	$377,339	$ 281,383	$(10,525)	$ 648,197
Stock options exercised	1,206	6,561	—	—	6,561
Employee stock plan grants	105	4,841	—	—	4,841
Shares re-issued from treasury	—	(587)	(9,938)	10,525	—
Net share settlements	(502)	—	(23,707)	—	(23,707)
Fair value of employee stock plan grants	—	21,103	—	—	21,103
Excess tax benefit on stock based compensation	—	17,522	—	—	17,522
Net income		—	464,459	—	464,459
Balances at December 31, 2010	152,568	$426,779	$ 712,197	$ —	$ 1,138,976
Stock options exercised	672	9,928	—	—	9,928
Employee stock plan grants	150	—	—	700	700
Shares repurchased	(588)	—	—	(20,868)	(20,868)
Shares re-issued from treasury	—	(686)	(4,531)	5,217	—
Net share settlements	(325)	—	(15,429)	—	(15,429)
Fair value of employee stock plan grants	—	20,988	—	—	20,988
Excess tax benefit on stock based compensation	—	6,212	—	—	6,212
Net income	—	—	453,202	—	453,202
Balances at December 31, 2011	152,477	$463,221	$ 1,145,439	$(14,951)	$ 1,593,709
Stock options exercised	34	632	—	—	632
Employee stock plan grants	708	613	—	—	613
Shares repurchased	(50)	—	—	(1,100)	(1,100)
Shares re-issued from treasury	—	(1,245)	(14,793)	16,038	—
Net share settlements	(239)	—	(5,618)	—	(5,618)
Fair value of employee stock plan grants	—	15,222	—	—	15,222
(Reduction in) tax benefit on stock based compensation	—	(4,427)	—	—	(4,427)
Net (loss)	—	—	(2,176,898)	—	(2,176,898)
Balances at December 31, 2012	152,930	$474,016	$(1,051,870)	$ (13)	$ (577,867)

See accompanying notes to consolidated financial statements.

ULTRA PETROLEUM CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2012	2011	2010
Cash provided by (used in):	**(Amounts in thousands of U.S. dollars)**		
Operating activities:			
Net (loss) income for the period	$(2,176,898)	$ 453,202	$ 464,459
Adjustments to reconcile net (loss) income to cash provided by operating activities:			
Depletion, depreciation and amortization	388,985	346,394	241,796
Ceiling test and other impairments	2,972,464	—	—
Deferred and current non-cash income taxes	(712,576)	251,206	253,926
Unrealized loss (gain) on commodity derivatives	230,385	(100,383)	(208,625)
Reduction in/(excess) tax benefit from stock based compensation	4,427	(6,212)	(17,522)
Stock compensation	10,756	13,919	12,944
Other	3,667	1,495	734
Net changes in operating assets and liabilities:			
Restricted cash	—	(23)	1,583
Accounts receivable	62,758	(26,910)	(31,966)
Prepaid expenses and other	2,066	(1,274)	(229)
Other non-current assets	284	—	(1,176)
Accounts payable and accrued liabilities	(115,597)	86,079	91,982
Production taxes payable	(14,372)	8,735	(7,439)
Interest payable	(213)	3,428	14,867
Other long-term obligations	(9,031)	433	6,035
Current taxes payable	7,720	3,203	3,359
Net cash provided by operating activities	654,825	1,033,292	824,728
Investing Activities:			
Acquisition of oil and gas properties	—	—	(403,806)
Oil and gas property expenditures	(708,017)	(1,435,611)	(1,164,389)
Gathering system expenditures	(127,149)	(83,996)	(76,703)
Proceeds from sale of oil and gas properties	—	5,821	68,420
Proceeds from sale of liquids gathering system (See Note 4)	203,046	—	—
Proceeds from sale of marketable securities (See Note 4)	21,235	—	—
Change in capital cost accrual	38,338	125,261	19,826
Restricted cash	—	—	28,257
Inventory	(374)	1,595	1,738
Purchase of property, plant and equipment	(4,302)	(21,865)	(2,442)
Net cash used in investing activities	(577,223)	(1,408,795)	(1,529,099)
Financing activities:			
Borrowings on long-term debt	852,000	1,257,000	1,000,000
Payments on long-term debt	(918,000)	(914,000)	(1,260,000)
Proceeds from issuance of Senior Notes	—	—	1,025,000
Deferred financing costs	—	(6,866)	(4,425)
Repurchased shares/net share settlements	(6,718)	(36,298)	(23,707)
(Reduction in)/excess tax benefit from stock based compensation	(4,427)	6,212	17,522
Proceeds from exercise of options	1,157	9,928	6,561
Net cash (used in) provided by financing activities	(75,988)	315,976	760,951
Increase (decrease) in cash during the period	1,614	(59,527)	56,580
Cash and cash equivalents, beginning of period	11,307	70,834	14,254
Cash and cash equivalents, end of period	$ 12,921	$ 11,307	$ 70,834
SUPPLEMENTAL INFORMATION:			
Cash paid for:			
Interest	$ 101,237	$ 88,964	$ 53,291
Income taxes	$ 4,379	$ 7,260	$ 2,537

See accompanying notes to consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(All amounts in this Report on Form 10-K are expressed in thousands of U.S. dollars (except per share data), unless otherwise noted).

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 the north-central Pennsylvania area of the Appalachian Basin.

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. The Company presents its financial statements in accordance with U.S. Generally Accepted Accounting Principles ("GAAP"). All inter-company transactions and balances have been eliminated upon consolidation.

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

(c) *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.

(d) *Property, plant and equipment:* Capital assets are recorded at cost and depreciated using the declining-balance method based on a seven-year useful life. Gathering system expenditures are recorded at cost and depreciated using the straight-line method based on a 30-year useful life. The gathering system assets which are downstream of the Company's well pads are depreciated separately from proven oil and gas properties because they are expected to be used to transport oil and gas not currently included in the Company's proved reserves, including production expected from probable and possible reserves, as well as from third parties.

The Company recognized impairments of $92.5 million during the year ended December 31, 2012 related to the decline in fair value as defined in FASB ASC 820 as a result of forecast decreased throughput volumes on its gathering facilities in Pennsylvania due to the decline in commodity prices. These assets are included in Property, Plant and Equipment in the Consolidated Balance Sheets.

(e) *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") Release No. 33-8995, Modernization of Oil and Gas Reporting Requirements ("SEC Release No. 33-8995") and Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 932, Extractive Activities – Oil and Gas ("FASB ASC 932"). 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. 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 proved reserves as determined by independent petroleum engineers. Oil and natural gas reserves and production are converted into equivalent units based on relative energy content. Asset retirement obligations are included in the base costs for calculating depletion.

Under the full cost method, costs of unevaluated properties and major development projects expected to require significant future costs may be excluded from capitalized costs being amortized. The Company excludes significant costs until proved reserves are found or until it is determined that the costs are impaired. Excluded costs, if any, are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the capitalized costs being amortized.

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, utilizing the average of prices in effect on the first day of the month for the preceding twelve month period in accordance with SEC Release No. 33-8995. 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 results in a lower depletion, depreciation and amortization ("DD&A") rate 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.

During 2012, the Company recorded a $2.9 billion non-cash write-down of the carrying value of the Company's proved oil and gas properties as a result of ceiling test limitations, which is reflected within ceiling test and other impairments in the accompanying Consolidated Statements of Operations. The ceiling test was calculated based upon the average of quoted market prices in effect on the first day of the month for the preceding twelve month period at December 31, 2012, September 30, 2012 and June 30, 2012 of $2.76 per MMBtu, $2.83 per MMBtu and $3.15 per MMBtu for Henry Hub natural gas, respectively, and $94.71 per barrel, $94.97 per barrel and $95.67 per barrel for West Texas Intermediate oil, respectively, adjusted for market differentials. The Company did not have any write-downs related to the full cost ceiling limitation in 2011 or 2010.

(f) *Inventories:* Materials and supplies inventories are carried at lower of cost or market. Inventory costs include expenditures and other charges directly and indirectly incurred in bringing the inventory to its existing condition and location. 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. At December 31, 2012, inventory of $1.5 million primarily includes the cost of pipe and production equipment that will be utilized during the 2013 drilling program.

(g) *Derivative instruments and hedging activities:* The Company follows FASB ASC Topic 815, Derivatives and Hedging ("FASB ASC 815"). The Company records the fair value of its commodity derivatives as an asset or liability on the Consolidated Balance Sheets, and records the changes in the fair value of its commodity derivatives in the Consolidated Statements of Operations as an unrealized gain or loss on commodity derivatives. The Company does not offset the value of its derivative arrangements with the same counterparty. (See Note 7).

(h) *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. Valuation allowances are recorded related to deferred tax assets based on the "more likely than not" criteria described in FASB ASC Topic 740, Income Taxes. In addition, the Company recognizes the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit.

As a result of the tax effect of the ceiling test and other impairments recorded during the year ended December 31, 2012, the Company's previously recorded net deferred tax liability fully reversed into a net deferred tax asset. The Company has recorded a full valuation allowance against its net deferred tax asset balance of $449.8 million as of December 31, 2012. This valuation allowance may be reversed in future periods against future taxable income.

(i) *Earnings per share:* Basic (loss) earnings per share is computed by dividing net (loss) earnings attributable to common stockholders by the weighted average number of common shares outstanding during each period. Diluted (loss) 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.

The following table provides a reconciliation of components of basic and diluted net (loss) income per common share:

	December 31,		
	2012	2011	2010
Net (loss) income	$(2,176,898)	$453,202	$464,459
Weighted average common shares outstanding during the period	152,845	152,754	152,346
Effect of dilutive instruments	—(1)	1,582	1,907
Weighted average common shares outstanding during the period including the effects of dilutive instruments	152,845	154,336	154,253
Net (loss) income per common share — basic	$ (14.24)	$ 2.97	$ 3.05
Net (loss) income per common share — fully diluted	$ (14.24)	$ 2.94	$ 3.01
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	—(1)	1,030	1,214

(1) Due to the net loss for the year ended December 31, 2012, 1.9 million shares for options and restricted stock units were anti-dilutive and excluded from the computation of loss per share.

(j) *Use of estimates:* Preparation of consolidated financial statements in accordance with U.S. GAAP 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.

(k) *Accounting for share-based compensation:* The Company measures and recognizes compensation expense for all share-based payment awards made to employees and directors, including employee stock options, based on estimated fair values in accordance with FASB ASC Topic 718, Compensation – Stock Compensation.

(l) *Fair value accounting:* The Company follows FASB ASC Topic 820, Fair Value Measurements and Disclosures ("FASB ASC 820"), which defines fair value, establishes a framework for measuring fair value under GAAP, and expands disclosures about fair value measurements. This statement applies under other accounting topics that require or permit fair value measurements. See Note 8 for additional information.

(m) *Asset retirement obligation:* The initial estimated retirement obligation of properties is recognized as a liability with an associated increase in oil and gas properties for the asset retirement cost. Accretion expense is recognized over the estimated productive life of the related assets. If the fair value of the estimated asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the asset retirement cost. Revisions in estimated liabilities can result from revisions of estimated inflation rates, changes in service and equipment costs and changes in the estimated timing of settling asset retirement obligations. As a full cost company, settlements for asset retirement obligations for abandonment are adjusted to the full cost pool. The asset retirement obligation is included within other long-term obligations in the accompanying Consolidated Balance Sheets.

(n) *Revenue recognition:* The Company generally sells natural gas and condensate 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 collectability 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. 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, 2012 and 2011, the Company had a net natural gas imbalance liability of $2.1 million and $1.3 million, respectively.

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.

(o) *Capitalized interest:* Interest is capitalized on the cost of unevaluated gas and oil properties that are excluded from amortization and actively being evaluated, if any, as well as on work in process relating to gathering systems that are not currently in service.

(p) *Capital cost accrual:* The Company accrues for exploration and development costs in the period incurred, while payment may occur in a subsequent period.

(q) *Reclassifications:* Certain amounts in the financial statements of prior periods have been reclassified to conform to the current period financial statement presentation.

(r) *Recent accounting pronouncements:* In May 2011, the FASB issued ASU No. 2011-04, which amends FASB ASC 820. The amended guidance clarifies many requirements in U.S. GAAP for measuring fair value and for disclosing information about fair value measurements. Additionally, the amendments clarify the FASB's intent about the application of existing fair value measurement requirements. The guidance provided in ASU No. 2011-04 is effective for interim and annual periods beginning after December 15, 2011. The adoption of this amendment did not have a material impact on the Company's consolidated financial statements.

2. ASSET RETIREMENT OBLIGATIONS:

The Company is required 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. The following table summarizes the activities for the Company's asset retirement obligations for the years ended:

	December 31,	
	2012	2011
Asset retirement obligations at beginning of period	$42,052	$28,052
Accretion expense	4,922	3,088
Liabilities incurred	13,638	10,878
Liabilities settled	(1,182)	(3)
Revisions of estimated liabilities	1,384	37
Asset retirement obligations at end of period	60,814	42,052
Less: current asset retirement obligations	(702)	—
Long-term asset retirement obligations	$60,112	$42,052

3. OIL AND GAS PROPERTIES:

	December 31, 2012	December 31, 2011
Proven Properties:		
Acquisition, equipment, exploration, drilling and environmental costs	$ 7,235,765	$ 5,974,604
Less: Accumulated depletion, depreciation and amortization(1)	(5,578,265)	(2,322,982)
	1,657,500	3,651,622
Unproven Properties:		
Acquisition and exploration costs not being amortized(2)	—	537,526
Net capitalized costs — oil and gas properties	$ 1,657,500	$ 4,189,148

On a unit basis, DD&A from continuing operations was $1.51, $1.41 and $1.13 per Mcfe for the years ended December 31, 2012, 2011 and 2010, respectively.

(1) During 2012, the Company recorded a $2.9 billion non-cash write-down of the carrying value of the Company's proved oil and gas properties as a result of ceiling test limitations, which is reflected within

ceiling test and other impairments in the accompanying Consolidated Statements of Operations. The ceiling test was calculated based upon the average of quoted market prices in effect on the first day of the month for the preceding twelve month period at December 31, 2012, September 30, 2012 and June 30, 2012 of $2.76 per MMBtu, $2.83 per MMBtu and $3.15 per MMBtu for Henry Hub natural gas, respectively, and $94.71 per barrel, $94.97 per barrel and $95.67 per barrel for West Texas Intermediate oil, respectively, adjusted for market differentials. The Company did not have any write-downs related to the full cost ceiling limitation in 2011.

(2) Interest is capitalized on the cost of unevaluated oil and natural gas properties that are excluded from amortization and actively being evaluated as well as on work in process relating to gathering systems that are not currently in service. For the years ended December 31, 2012 and 2011, total interest on outstanding debt was $103.2 million and $93.9 million, respectively, of which $15.0 million and $30.7 million, respectively, was capitalized on the cost of unevaluated oil and natural gas properties and work in process relating to gathering systems that are not currently in service.

At December 31, 2012, all costs related to unevaluated properties that were previously excluded from capitalized costs being amortized have been impaired and transferred to the capitalized costs being amortized in the full cost pool.

	Total	2012	2011	2010	Prior
Acquisition costs	$—	$(481,689)	$24,583	$411,326	$45,780
Exploration costs	—	(9,962)	198	—	9,764
Capitalized interest	—	(45,875)	26,498	19,377	—
Unproven properties	$—	$(537,526)	$51,279	$430,703	$55,544

4. PROPERTY, PLANT AND EQUIPMENT:

	December 31,			
	2012			2011
	Cost	Accumulated Depreciation	Net Book Value	Net Book Value
Gathering systems(1),(2)	$282,879	$ (99,312)	$183,567	$219,011
Computer equipment	2,510	(1,510)	1,000	1,025
Office equipment	454	(374)	80	109
Leasehold improvements	450	(251)	199	307
Land	22,359	—	22,359	22,150
Other	11,358	(6,191)	5,167	3,984
Property, Plant and Equipment, Net	$320,010	$(107,638)	$212,372	$246,586

(1) The Company recognized impairments of $92.5 million during the year ended December 31, 2012 related to the decline in fair value as defined in FASB ASC 820 as a result of forecast decreased throughput volumes on its gathering facilities in Pennsylvania due to the decline in commodity prices.

(2) During December 2012, the Company sold its system of pipelines and central gathering facilities (the "LGS") and certain associated real property rights in the Pinedale Anticline in Wyoming. The net cash proceeds received for the assets were $203.0 million and additional consideration of $23.0 million in the form of marketable securities which were sold during December 2012 for net cash proceeds of

$21.2 million. The Company entered into a long-term, triple net lease agreement with the buyer relating to the use of the LGS (the "Lease Agreement"). The Lease Agreement provides for an initial term of 15 years and potential successive renewal terms of 5 years or 75% of the then remaining useful life of the LGS at the sole discretion of the Company. Annual rent for the initial term under the Lease Agreement is $20.0 million (as adjusted annually for changes based on the consumer price index) and may increase if certain volume thresholds are exceeded. The Company's sale leaseback transaction was treated as a "normal leaseback" under the provisions of FASB ASC Topic 840, Leases ("FASB ASC Topic 840") and qualified for sales recognition. The lease is classified as an operating lease.

In Pennsylvania, the Company and its partners continue constructing gas gathering pipelines and facilities, compression facilities and pipeline delivery stations to gather production from its newly completed natural gas wells. These facilities are gathering systems and related infrastructure, and their construction is expected to continue until the Company's properties in Pennsylvania are fully developed. To date, none of the Company's natural gas production in Pennsylvania has required processing, treating or blending in order to remove natural gas liquids or other impurities and it is anticipated that facilities of this type will not be required in the future to accommodate the Company's production.

5. LONG-TERM LIABILITIES:

	December 31, 2012	December 31, 2011
Bank indebtedness	$ 277,000	$ 343,000
Senior notes	1,560,000	1,560,000
Other long-term obligations	76,038	67,008
	$1,913,038	$1,970,008

Aggregate maturities of debt at December 31, 2012:

2013	2014	2015	2016	2017	Beyond 5 years	Total
$—	$—	$100,000	$339,000	$116,000	$1,282,000	$1,837,000

Bank indebtedness. The Company (through its subsidiary, Ultra Resources, Inc.) is a party to a revolving credit facility with a syndicate of banks led by JP Morgan Chase Bank, N.A. (the "Credit Agreement"). The Credit Agreement provides an initial loan commitment of $1.0 billion, which may be increased up to $1.25 billion at the request of the borrower and with the lenders' consent, provides for the issuance of letters of credit of up to $250.0 million in aggregate, and matures in October 2016 (which term may be extended for up to two successive one-year periods at the Borrower's request and with the lenders' consent). At December 31, 2012, the Company had $277.0 million in outstanding borrowings and $723.0 million of available borrowing capacity under the Credit Agreement.

Loans under the Credit Agreement are unsecured and bear interest, at the Borrower's option, based on (A) a rate per annum equal to the prime rate or the weighted average fed funds rate on overnight transactions during the preceding business day plus 100 basis points, or (B) a base Eurodollar rate, substantially equal to the LIBOR rate, plus a margin based on a grid of the Borrower's consolidated leverage ratio (200 basis points per annum as of December 31, 2012). The Company also pays commitment fees on the unused commitment under the facility based on a grid of its consolidated leverage ratio.

The Credit Agreement contains typical and customary representations, warranties, covenants and events of default. The Credit Agreement includes restrictive covenants requiring the Borrower to maintain a consolidated leverage ratio of no greater than three and one half times to one and, as long as the Company's debt rating is below investment grade, the maintenance of an annual ratio of the net present value of the Company's oil and gas properties to total funded debt of no less than one and one half times to one. At December 31, 2012, the Company was in compliance with all of its debt covenants under the Credit Agreement.

Senior Notes: The Company's Senior Notes rank pari passu with the Company's Credit Agreement. Payment of the Senior Notes is guaranteed by Ultra Petroleum Corp. and UP Energy Corporation. The Senior Notes are pre-payable in whole or in part at any time and are subject to representations, warranties, covenants and events of default customary for a senior note financing. At December 31, 2012, the Company was in compliance with all of its debt covenants under the Senior Notes.

Other long-term obligations: These costs primarily relate to the long-term portion of production taxes payable and our asset retirement obligations.

6. SHARE BASED COMPENSATION:

The Company sponsors a share based compensation plan: the 2005 Stock Incentive Plan (the "2005 Plan"). The plan is administered by the Compensation Committee of the Board of Directors (the "Committee"). The share based compensation plan is an important component of the total compensation package offered to the Company's key service providers, and reflects the importance that the Company places on motivating and rewarding superior results.

The 2005 Plan was adopted by the Company's Board of Directors on January 1, 2005 and approved by the Company's shareholders on April 29, 2005. The purpose of the 2005 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 outside directors, and providing such participants 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, and thus, enabling such participants to share in the long-term growth and success of the Company. To accomplish these goals, the 2005 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 Committee determines the terms and conditions of the awards, including, any vesting requirements and vesting restrictions or forfeitures that may occur. The Committee may grant awards under the 2005 Plan until December 31, 2014, unless terminated sooner by the Board of Directors.

Valuation and Expense Information

	Year Ended December 31,		
	2012	2011	2010
Total cost of share-based payment plans	$15,835	$21,688	$21,805
Amounts capitalized in fixed assets	$ 5,079	$ 7,769	$ 8,861
Amounts charged against income, before income tax benefit	$10,756	$13,919	$12,944
Amount of related income tax benefit recognized in income	$ 4,463	$ 4,997	$ 4,595

Securities Authorized for Issuance Under Equity Compensation Plans

As of December 31, 2012, 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 or shares issued from treasury.

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	1,357	$49.03	3,075
Equity compensation plans not approved by security holders	n/a	n/a	n/a
Total	1,357	$49.03	3,075

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, 2012:

	Number of Options	Weighted Average Exercise Price (US$)		
Balance, December 31, 2009	3,504	$ 1.49	to	$98.87
Forfeited	(68)	$51.60	to	$76.01
Exercised	(1,206)	$ 1.49	to	$45.95
Balance, December 31, 2010	2,230	$ 3.91	to	$98.87
Forfeited	(99)	$51.60	to	$75.18
Exercised	(672)	$ 3.91	to	$33.57
Balance, December 31, 2011	1,459	$16.97	to	$98.87
Forfeited	(68)	$25.08	to	$75.18
Exercised	(34)	$16.97	to	$19.18
Balance, December 31, 2012	1,357	$16.97	to	$98.87

The following table summarizes information about the stock options outstanding and exercisable at December 31, 2012:

	Options Outstanding and Exercisable			
Range of Exercise Price	Number Outstanding	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Aggregate Intrinsic Value
		(Years)		
$16.97 - $16.97	40	1.32	$16.97	$ 46
$25.68 - $55.58	604	2.61	$39.21	$ —
$46.05 - $65.04	166	3.53	$56.44	$ —
$49.05 - $65.94	362	4.31	$54.66	$ —
$51.14 - $98.87	185	5.42	$70.24	$ —

The aggregate intrinsic value in the preceding tables represents the total pre-tax intrinsic value, based on the Company's closing stock price of $18.13 on December 31, 2012, 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, 2012 was 40,000 options.

The following table summarizes information about the weighted-average grant-date fair value of share options:

	2012	2011	2010
Non-vested share options at beginning of year	$ —	$30.72	$26.28
Non-vested share options at end of year	$ —	$ —	$30.72
Options vested during the year	$ —	$30.73	$23.86
Options forfeited during the year	$27.05	$25.80	$28.36

The fair value of stock options that vested during the years ended December 31, 2011 and 2010 was $6.4 million and $9.8 million, respectively. As of December 31, 2011, all options fully vested; therefore, no options vested during the year ended December 31, 2012. The total intrinsic value of stock options exercised during the years ended December 31, 2012, 2011 and 2010 was $0.3 million, $21.5 million and $50.7 million, respectively.

At December 31, 2012, there was no unrecognized compensation cost related to non-vested, employee stock options as all options fully vested as of December 31, 2011.

PERFORMANCE SHARE PLANS:

Long Term Incentive Plans. The Company offers a Long Term Incentive Plan ("LTIP") in order to further align the interests of key employees with shareholders and to give key employees the opportunity to share in the long-term performance of the Company when specific corporate financial and operational goals are achieved. Each LTIP covers a performance period of three years. In 2010, 2011 and 2012, the Compensation Committee (the "Committee") approved an award consisting of performance-based restricted stock units to be awarded to each participant.

For each LTIP award, the Committee establishes performance measures at the beginning of each performance period. Under each LTIP, the Committee establishes a percentage of base salary for each participant which is multiplied by the participant's base salary to derive a Long Term Incentive Value as a "target" value which corresponds to the number of shares of the Company's common stock the participant is eligible to receive if the target level for all performance measures is met. In addition, each participant is assigned threshold and maximum award levels in the event that actual performance is below or above target levels. For the 2010, 2011 and 2012 LTIP awards, the Committee established the following performance measures: return on equity, reserve replacement ratio, and production growth.

For the year ended December 31, 2012, the Company recognized $7.9 million in pre-tax compensation expense related to the 2010, 2011 and 2012 LTIP awards of restricted stock units. For the year ended December 31, 2011, the Company recognized $10.7 million in pre-tax compensation expense related to the 2009, 2010 and 2011 LTIP awards of restricted stock units. For the year ended December 31, 2010, the Company recognized $8.6 million in pre-tax compensation expense related to the 2008, 2009 and 2010 LTIP awards of restricted stock units. The amounts recognized during the year ended December 31, 2012 assumes that maximum performance objectives are attained under each plan. If the Company ultimately attains these performance objectives, the associated total compensation, estimated at December 31, 2012, for each of the three year performance periods is expected to be approximately $11.7 million, $11.9 million, and $12.1 million related to the 2010, 2011 and 2012 LTIP awards of restricted stock units, respectively. The 2009 LTIP Common Stock Award was paid in shares of the Company's stock to employees during the first quarter of 2012 and totaled $24.1 million (409,160 net shares).

7. DERIVATIVE FINANCIAL INSTRUMENTS:

Objectives and Strategy: 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.

Historically, the Company has entered into various types of derivative instrument transactions to manage its exposure to commodity price risk and to provide a level of certainty in the Company's forward cash flows supporting the Company's capital investment program. Because forward natural gas prices for 2013 production were low in 2012, the Company did not hedge any of its forecast 2013 natural gas production. As a result of the Company not having hedged any of its 2013 production, its earnings and cash flows may be more volatile during 2013 than in prior years.

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 or greater than the spot prices that it would have received otherwise.

Fair Value of Commodity Derivatives: FASB ASC 815 requires that all derivatives be recognized on the balance sheet as either an asset or liability and be measured at fair value. Changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. The Company does not apply hedge accounting to any of its derivative instruments.

Derivative contracts that do not qualify for hedge accounting treatment are recorded as derivative assets and liabilities at fair value on the balance sheet and the associated unrealized gains and losses are recorded as current expense or income in the income statement. Unrealized gains or losses on commodity derivatives represent the non-cash change in the fair value of these derivative instruments and do not impact operating cash flows on the cash flow statement.

The following table summarizes the pre-tax realized and unrealized gains and losses the Company recognized related to its natural gas derivative instruments in the Consolidated Statements of Operations for the years ended December 31, 2012, 2011 and 2010:

	For the Year Ended December 31,		
	2012	2011	2010
Natural Gas Commodity Derivatives:			
Realized gain on commodity derivatives(1)	$ 303,966	$213,349	$116,827
Unrealized (loss) gain on commodity derivatives(1)	(230,385)	100,383	208,625
Total gain on commodity derivatives	$ 73,581	$313,732	$325,452

(1) Included in gain on commodity derivatives in the Consolidated Statements of Operations.

8. FAIR VALUE MEASUREMENTS:

In consideration of counterparty credit risk, the Company assessed the possibility of whether each counterparty to the derivative would default by failing to make any contractually required payments as scheduled in the derivative instrument in determining the fair value. Additionally, the Company considers that it is of substantial credit quality and has the financial resources and willingness to meet its potential repayment obligations associated with the derivative transactions.

As required by FASB ASC Topic 820, Fair Value Measurements and Disclosures ("FASB ASC 820"), the Company defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date and establishes a three level hierarchy for measuring fair value. Fair value measurements are classified and disclosed in one of the following categories:

Level 1: Quoted prices (unadjusted) in active markets for identical assets and liabilities that we have the ability to access at the measurement date.

Level 2: Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are observable for the asset or liability, and inputs that are derived from observable market data by correlation or other means. Instruments categorized in Level 2 include non-exchange traded derivatives such as over-the-counter forwards and swaps.

Level 3: Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability.

The valuation assumptions the Company has used to measure the fair value of its commodity derivatives were observable inputs based on market data obtained from independent sources and are considered Level 2 inputs (quoted prices for similar assets, liabilities (adjusted) and market-corroborated inputs). At December 31, 2012, the Company did not have any open commodity derivative contracts.

In consideration of counterparty credit risk, the Company assessed the possibility of whether each counterparty to the derivative would default by failing to make any contractually required payments as scheduled in the derivative instrument in determining the fair value. Additionally, the Company considers that it is of substantial credit quality and has the financial resources and willingness to meet its potential repayment obligations associated with the derivative transactions. At December 31, 2012, the Company did not have any open commodity derivative contracts.

Fair Value of Long-Lived Assets

The Company recognized impairments of $92.5 million during the year ended December 31, 2012 related to the decline in fair value as defined in FASB ASC 820 as a result of forecast decreased throughput volumes on its gathering facilities in Pennsylvania due to the decline in commodity prices. These facilities are included in Property, Plant and Equipment in the Consolidated Balance Sheets and were impaired to a fair value of $82.6 million based on the income approach, estimated using Level 3 fair value inputs.

Fair Value of Financial Instruments

The estimated fair value of financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amounts reported in the Consolidated Balance Sheets for cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the immediate or short-term maturity of these financial instruments. The carrying amount of floating-rate debt approximates fair value because the interest rates are variable and reflective of market rates. We use available market data and valuation methodologies to estimate the fair value of our fixed rate debt. The inputs utilized to estimate the fair value of the Company's fixed rate debt are considered Level 2 fair value inputs. This disclosure is presented in accordance with FASB ASC Topic 825, Financial Instruments, and does not impact our financial position, results of operations or cash flows.

	December 31, 2012		December 31, 2011	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Long-Term Debt:				
5.45% Notes due 2015, issued 2008	$ 100,000	$ 107,801	$ 100,000	$ 111,475
7.31% Notes due 2016, issued 2009	62,000	72,046	62,000	74,817
4.98% Notes due 2017, issued 2010	116,000	127,109	116,000	128,570
5.92% Notes due 2018, issued 2008	200,000	230,062	200,000	231,091
7.77% Notes due 2019, issued 2009	173,000	219,045	173,000	219,552
5.50% Notes due 2020, issued 2010	207,000	234,552	207,000	229,423
4.51% Notes due 2020, issued 2010	315,000	331,329	315,000	318,925
5.60% Notes due 2022, issued 2010	87,000	98,526	87,000	94,165
4.66% Notes due 2022, issued 2010	35,000	36,361	35,000	34,631
5.85% Notes due 2025, issued 2010	90,000	102,096	90,000	99,022
4.91% Notes due 2025, issued 2010	175,000	179,677	175,000	173,835
Credit Facility	277,000	277,000	343,000	343,000
	$1,837,000	$2,015,604	$1,903,000	$2,058,506

9. INCOME TAXES:

The consolidated income tax (benefit) provision is comprised of the following:

	Year Ended December 31,		
	2012	2011	2010
Current	$ 12,363	$ 6,464	$ 4,763
(Reduction in) current tax benefit on stock based compensation	(4,427)	6,212	17,522
Total current tax	7,936	12,676	22,285
Deferred	(708,149)	244,994	236,330
Total income tax (benefit) provision	$(700,213)	$257,670	$258,615

The income tax provision (benefit) for continuing operations 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,		
	2012	2011	2010
Income tax (benefit) provision computed at the U.S. statutory rate	$(1,006,989)	$248,805	$253,076
State income tax provision (benefit) net of federal benefit	(136,112)	6,329	3,608
Valuation allowance	446,148	—	(677)
Tax effect of rate change	1,358	4,228	1,939
Other, net	(4,618)	(1,692)	669
	$ (700,213)	$257,670	$258,615

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

	Year Ended December 31,	
	2012	2011
Deferred tax assets — current:		
Incentive compensation/other, net	6,468	9,329
Valuation allowance	(6,468)	—
Net deferred tax assets — current	$ —	$ 9,329
Deferred tax liabilities — current:		
Derivative instruments, net	$ —	$82,709
Net deferred tax liabilities — current	$ —	$82,709
Net deferred tax liability — current	$ —	$73,380

	Year Ended December 31,	
	2012	2011
Deferred tax assets — non-current:		
Property and equipment	350,978	—
Deferred gain	55,329	—
U.S. Federal tax credit carryforwards	4,870	13,280
Capital loss carryforwards	—	1,929
Net operating loss carryforwards	17,755	150
Incentive compensation/other, net	15,104	12,880
	444,036	28,239
Valuation allowance	(443,300)	(3,621)
Net deferred tax assets — non-current	$ 736	$ 24,618
Deferred tax liabilities — non-current:		
Property and equipment	—	659,040
Other	736	587
Net non-current tax liabilities	$ 736	$659,627
Net non-current tax liability	$ —	$635,009

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, historical taxable income, projected future taxable income, and available tax planning strategies.

As a result of the ceiling test and other impairments recorded during the year ended December 31, 2012, the Company's previously recorded net deferred tax liability fully reversed into a net deferred tax asset. The Company has recorded a full valuation allowance against its net deferred tax asset balance of $449.8 million as of December 31, 2012. This valuation allowance may be reversed in future periods against future taxable income.

As of December 31, 2012, the Company had approximately $3.2 million of U.S. federal alternative minimum tax (AMT) credits available to offset regular U.S. Federal income taxes. These AMT credits do not expire and can be carried forward indefinitely. In addition, the Company has $1.7 million of foreign tax credit carryforwards, none of which expire prior to 2017. The Company has U.S. State tax net operating loss carryforwards of $273.1 million which will expire between 2031 and 2032.

The Company did not have any unrecognized tax benefits and there was no effect on our financial condition or results of operations as a result of implementing the standard related to accounting for uncertain tax positions. The amount of unrecognized tax benefits did not change as of December 31, 2012.

Estimated interest and penalties related to potential underpayment on any unrecognized tax benefits are classified as a component of tax expense in the Consolidated Statements of Operations. The Company has not recorded any interest or penalties associated with unrecognized tax benefits.

The Company files a consolidated federal income tax return in the United States federal jurisdiction and various combined, consolidated, unitary, and separate filings in several states, and international jurisdictions. The income tax years 2009 and 2010 have been audited by the Internal Revenue Service resulting in no material changes to the Company's taxes. With certain exceptions, including previous audited tax years, the income tax years 2009 through 2012 remain open to examination by the major taxing jurisdictions in which the Company has business activity.

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.

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 100% of their compensation, subject to limitations. The Company matches 100% of the employee's contribution up to 5% of compensation, as defined by the plan, along with an employer discretionary contribution of 8%. The expense associated with the Company's contribution was $1.8 million, $1.4 million and $1.2 million for the years ended December 31, 2012, 2011 and 2010, respectively.

11. COMMITMENTS AND CONTINGENCIES:

Transportation contract. The Company is an anchor shipper on REX securing pipeline infrastructure providing sufficient capacity to transport a portion of its natural gas production away from southwest Wyoming and to provide for reasonable basis differentials for its natural gas in the future. REX begins at the Opal Processing Plant in southwest Wyoming and traverses Wyoming and several other states to an ultimate terminus in eastern Ohio. The Company's commitment involves a capacity of 200 MMMBtu per day of natural gas through November 2019, and the Company is obligated to pay REX certain demand charges related to its rights to hold this firm transportation capacity as an anchor shipper.

Subsequently, the Company entered into agreements to secure an additional capacity of 50 MMMBtu per day on the REX pipeline system, beginning in January 2012 through December 2018. This additional capacity will provide the Company with the ability to move additional volumes from its producing wells in Wyoming to markets in the eastern U.S.

The Company currently projects that demand charges related to the remaining term of the contract will total approximately $673.0 million.

Operating lease. During December 2012, the Company sold its system of pipelines and central gathering facilities (the "LGS") and certain associated real property rights in the Pinedale Anticline in Wyoming. The net cash proceeds received for the assets were $203.0 million and additional consideration of $23.0 million in the form of marketable securities which were sold during December 2012 for net cash proceeds of $21.2 million.

The Company entered into a long-term, triple net lease agreement with the buyer relating to the use of the LGS (the "Lease Agreement"). The Lease Agreement provides for an initial term of 15 years and potential successive renewal terms of 5 years or 75% of the then remaining useful life of the LGS at the sole discretion of the Company. Annual rent for the initial term under the Lease Agreement is $20.0 million (as adjusted annually for changes based on the consumer price index) and may increase if certain volume thresholds are exceeded. The Company's sale leaseback transaction was treated as a "normal leaseback" under the provisions of FASB ASC Topic 840 and qualified for sales recognition. The lease is classified as an operating lease. The Company currently projects that lease payments related to the Lease Agreement will total approximately $299.4 million.

All of the Company's lease obligations are related to leases that are classified as operating leases. These leases contain certain provisions that could result in accelerated lease payments. The Company has considered the effect of these provisions on minimum lease payments in its lease classification analysis and has determined that the default provisions do not impact classification of any the Company's operating leases.

Drilling contracts. As of December 31, 2012, the Company had committed to drilling obligations totaling $21.5 million ($15.0 million due in 2013, $6.5 million due in 2014). The commitments expire in 2014 and were entered into to fulfill the Company's drilling program initiatives in Wyoming.

Office space lease. The Company's maintains office space in Colorado, Texas, Wyoming and Pennsylvania with total remaining commitments for office leases of $1.5 million at December 31, 2012 ($0.9 million in 2013, $0.7 million in 2014 to 2015).

During the years ended December 31, 2012, 2011 and 2010, the Company recognized expense associated with its office leases in the amount of $1.0 million, $0.9 million, and $0.8 million, respectively.

Other. 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.

12. CONCENTRATION OF CREDIT RISK:

The Company's financial instruments that are exposed to concentrations of credit risk consist primarily of trade receivables and commodity derivative contracts associated with the Company's hedging program. The Company's revenues related to natural gas sales are derived principally from a diverse group of companies, including major energy companies, natural gas utilities, oil refiners, pipeline companies, local distribution companies, financial institutions and end-users in various industries.

Concentrations of credit risk with respect to receivables is limited due to the large number of customers and their dispersion across geographic areas. Commodity-based contracts may expose the Company to the credit risk of nonperformance by the counterparty to these contracts. This credit exposure to the Company is diversified primarily among as many as ten major investment grade institutions and will only be present if the reference price of natural gas established in those contracts is less than the prevailing market price of natural gas, from time to time. At December 31, 2012, the Company did not have any open commodity derivative contracts.

The Company maintains credit policies intended to monitor and mitigate the risk of uncollectible accounts receivable related to the sale of natural gas, condensate as well as its commodity derivative positions. The Company performs a credit analysis of each of its customers and counterparties prior to making any sales to new customers or extending additional credit to existing customers. Based upon this credit analysis, the Company may require a standby letter of credit or a financial guarantee. The Company did not have any outstanding, uncollectible accounts for its natural gas or condensate sales, nor derivative settlements sales at December 31, 2012.

A significant counterparty is defined as one that individually accounts for 10% or more of the Company's total revenues during the year. In 2012, the Company had no single customer that represented 10% or more of its total revenues.

13. SUBSEQUENT EVENTS:

FASB ASC Topic 855, Subsequent Events ("FASB ASC 855"), sets forth principles and requirements to be applied to the accounting for and disclosure of subsequent events. FASB ASC 855 sets forth the period after the balance sheet date during which management shall evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements, the circumstances under which events or transactions occurring after the balance sheet date shall be recognized in the financial statements and the required disclosures about events or transactions that occurred after the balance sheet date. The FASB issued ASU No. 2010-09, Subsequent Events (FASB ASC 855), Amendments to Certain Recognition and Disclosure Requirement*s,* on February 24, 2010, in an effort to remove some contradictions between the requirements of U.S. GAAP and the SEC's filing rules. The amendments remove the requirement that public companies disclose the date through which their financial statements are evaluated for subsequent events in both issued and revised financial statements. The Company has evaluated the period subsequent to December 31, 2012 for events that did not exist at the balance sheet date but arose after that date and determined that no subsequent events arose that should be disclosed in order to keep the financial statements from being misleading.

14. SUMMARIZED QUARTERLY FINANCIAL INFORMATION (UNAUDITED):

	2012				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total
Revenues from continuing operations	$226,143	$ 170,270	$ 196,375	$ 217,186	$ 809,974
Gain (loss) on commodity derivatives	120,283	(33,287)	(9,896)	(3,519)	73,581
Expenses from continuing operations	193,539	186,064	156,503	146,682	682,788
Ceiling test and other impairments	—	1,869,136	606,827	496,501	2,972,464
Interest expense	18,298	18,748	25,369	25,765	88,180
Contract cancellation fees	4,846	4,666	(291)	6,248	15,469
Other income (expense), net	8	7	(42)	(1,738)	(1,765)
Income (loss) before income tax provision	129,751	(1,941,624)	(601,971)	(463,267)	(2,877,111)
Income tax provision (benefit)	45,489	(754,642)	175	8,765	(700,213)
Net income (loss)	$ 84,262	$(1,186,982)	$(602,146)	$(472,032)	$(2,176,898)
Net income (loss) per common share — basic	$ 0.55	$ (7.76)	$ (3.94)	$ (3.09)	$ (14.24)
Net income (loss) per common share — fully diluted	$ 0.55	$ (7.76)	$ (3.94)	$ (3.09)	$ (14.24)

	2011				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total
Revenues from continuing operations	$257,290	$280,567	$293,141	$270,798	$1,101,796
Gain on commodity derivatives	15,635	47,606	114,166	136,325	313,732
Expenses from continuing operations	145,666	151,365	160,543	184,458	642,032
Interest expense	14,590	15,590	15,902	17,074	63,156
Other income (expense), net	20	(4)	(3)	519	532
Income before income tax provision	112,689	161,214	230,859	206,110	710,872
Income tax provision	43,969	57,709	81,713	74,279	257,670
Net income	$ 68,720	$103,505	$149,146	$131,831	$ 453,202
Net income per common share — basic	$ 0.45	$ 0.68	$ 0.98	$ 0.86	$ 2.97
Net income per common share — fully diluted	$ 0.44	$ 0.67	$ 0.97	$ 0.86	$ 2.94

15. 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 FASB ASC Topic 932, Oil and Gas Reserve Estimation and Disclosures:

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. From time to time, the Company may adjust the inventory and schedule of its proved undeveloped locations in response to changes in capital budget, economics, new opportunities in the portfolio or resource availability. The Company has not scheduled any proved undeveloped reserves beyond five years nor does it have any proved undeveloped locations that have been part of its inventory of proved undeveloped locations for over five years.

In estimating proved reserves and future revenue as of December 31, 2012, the Company's independent reserve engineer, Netherland, Sewell & Associates, Inc., used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information and property ownership interests. The reserves were estimated using deterministic methods; these estimates were prepared in accordance with generally accepted petroleum engineering and evaluation principles. Standard engineering and geoscience methods, such as reservoir modeling, performance analysis, volumetric analysis and analogy, that were considered to be appropriate and necessary to establish reserve quantities and reserve categorization that conform to SEC definitions and guidelines, were also used. As in all aspects of oil and natural gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, Netherland, Sewell & Associates, Inc.'s conclusions necessarily represent only informed professional judgment.

Our policies and practices regarding internal controls over the recording of reserves is structured to objectively and accurately estimate our oil and gas reserves quantities and present values in compliance with the

SEC's regulations and GAAP. The Vice President — Reservoir Engineering & Development is primarily responsible for overseeing the preparation of the Company's reserve estimates by our independent engineers, Netherland, Sewell & Associates, Inc. The Vice President — Reservoir Engineering & Development has a Bachelor and Master of Science degree in Petroleum Engineering and is a licensed Professional Engineer with over 18 years of experience. The Company's internal controls over reserve estimates include reconciliation and review controls, including an independent internal review of assumptions used in the estimation.

All of the information regarding reserves in this annual report is derived from the report of Netherland, Sewell & Associates, Inc. The report of Netherland, Sewell & Associates, Inc. is included as an Exhibit to this annual report. The principal engineer at Netherland, Sewell & Associates, Inc. responsible for preparing our reserve estimates has a Bachelor of Science degree in Mechanical Engineering and is a licensed Professional Engineer with 30 years of experience, including significant experience throughout the Rocky Mountain basins.

Since January 1, 2012, no crude oil or natural gas reserve information has been filed with, or included in any report to, any federal authority or agency other than the SEC and the Energy Information Administration ("EIA") of the U.S. Department of Energy. We file Form 23, including reserve and other information, with the EIA.

The following unaudited tables as of December 31, 2012, 2011, and 2010 are based upon estimates prepared by Netherland, Sewell & Associates, Inc. in reports dated February 11, 2013, February 1, 2012, and January 31, 2011, respectively. 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, 2012, 2011 and 2010. All such reserves are located in the Green River Basin in Wyoming and the Appalachian Basin of Pennsylvania.

B. ANALYSES OF CHANGES IN PROVEN RESERVES:

	United States	
	Oil (MBbls)	Natural Gas (MMcf)
Reserves, December 31, 2009	29,185	3,736,601
Extensions, discoveries and additions	8,496	1,195,829
Production	(1,334)	(205,613)
Revisions	(4,663)	(526,662)
Reserves, December 31, 2010	31,684	4,200,155
Extensions, discoveries and additions	7,425	1,452,122
Production	(1,408)	(236,832)
Revisions	(4,620)	(636,891)
Reserves, December 31, 2011	33,081	4,778,554
Extensions, discoveries and additions	5,435	819,896
Production	(1,282)	(249,310)
Revisions(1)	(19,097)	(2,382,695)
Reserves, December 31, 2012	18,137	2,966,445

	United States	
	Oil (MBbls)	Natural Gas (MMcf)
Proved:		
Developed	11,627	1,541,813
Undeveloped	17,558	2,194,788
Total Proved — 2009	29,185	3,736,601
Developed	11,013	1,678,697
Undeveloped	20,671	2,521,458
Total Proved — 2010	31,684	4,200,155
Developed	11,794	1,973,391
Undeveloped	21,287	2,805,163
Total Proved — 2011	33,081	4,778,554
Developed	10,531	1,820,994
Undeveloped	7,606	1,145,451
Total Proved — 2012	18,137	2,966,445

(1) The net downward revision is primarily due to lower natural gas prices utilized in the preparation of the December 31, 2012 reserve estimation as compared to the price used in the previous year's estimate impacting the economic limit of reserves and the corresponding reduction in capital investment associated with the transfer of proved undeveloped reserves to the unproven category. The calculated weighted average natural gas sales prices utilized for the purposes of estimating the Company's proved reserves and future net revenues at December 31, 2012 and 2011 were $2.63 per Mcf and $4.04 per Mcf, respectively.

During 2012, substantially all of our extensions and discoveries in the proved developed category were attributable to wells drilled in 2012, and substantially all of our extensions and discoveries in the proved undeveloped category were attributable to our ongoing drilling activities and its associated effect on our proved undeveloped reserves estimates.

C. STANDARDIZED MEASURE:

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 at December 31, 2012, 2011 and 2010 was $2.63, $4.04 and $4.05 per Mcf, respectively, for natural gas and $87.85, $88.19 and $68.93 per barrel, respectively, for condensate, based upon the average of the price in effect on the first day of the month for the preceding twelve month period.

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.

	As of December 31,		
	2012	2011	2010
Future cash inflows	$ 9,380,970	$22,196,913	$19,186,072
Future production costs	(3,217,771)	(6,113,282)	(5,253,509)
Future development costs	(1,661,394)	(4,294,375)	(3,052,843)
Future income taxes	(733,855)	(3,340,516)	(3,198,413)
Future net cash flows	3,767,950	8,448,740	7,681,307
Discount at 10%	(1,873,633)	(4,652,684)	(4,155,739)
Standardized measure of discounted future net cash flows	$ 1,894,317	$ 3,796,056	$ 3,525,568

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:

	December 31,		
	2012	2011	2010
Standardized measure, beginning	$ 3,796,056	$3,525,568	$2,026,700
Net revisions of previous quantity estimates	(2,516,159)	(964,987)	(807,877)
Extensions, discoveries and other changes	858,951	2,173,103	1,816,073
Changes in future development costs	952,067	(741,658)	(606,449)
Sales of oil and gas, net of production costs	(625,745)	(896,434)	(787,409)
Net change in prices and production costs	(2,912,698)	108,108	1,501,041
Development costs incurred during the period that reduce future development costs	316,394	464,880	404,402
Accretion of discount	529,696	499,358	288,713
Net changes in production rates and other	363,788	(338,982)	297,957
Net change in income taxes	1,131,967	(32,900)	(607,583)
Aggregate changes	(1,901,739)	270,488	1,498,868
Standardized measure, ending	$ 1,894,317	$3,796,056	$3,525,568

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:

	Years Ended December 31,		
	2012	2011	2010
United States			
Property Acquisitions:			
Unproved	$ 47,979	$ 91,983	$ 472,339
Proved	—	—	—
Exploration*	199,569	746,085	634,503
Development	587,618	675,718	469,636
Total	$835,166	$1,513,786	$1,576,478

* Exploration costs (as defined in Regulation S-X) includes costs spent on development of unproved reserves in the Pinedale Field.

F. RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES:

	Years Ended December 31,		
	2012	2011	2010
United States			
Oil and gas revenue	$ 809,974	$1,101,796	$ 979,386
Production expenses	(184,229)	(205,363)	(191,978)
Depletion and depreciation	(388,985)	(346,394)	(241,796)
Ceiling test and other impairments	(2,972,464)	—	—
Income taxes	662,698	(197,464)	(193,692)
Total	$(2,073,006)	$ 352,575	$ 351,920

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

	December 31,	
	2012	2011
Proven Properties:		
Acquisition, equipment, exploration, drilling and environmental costs	$ 7,235,765	$ 5,974,604
Less: accumulated depletion, depreciation and amortization	(5,578,265)	(2,322,982)
	1,657,500	3,651,622
Unproven Properties:		
Acquisition and exploration costs not being amortized	—	537,526
	$ 1,657,500	$ 4,189,148

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

None.

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

Management's Report on Internal Control Over Financial Reporting

Management's Report on Internal Control Over Financial Reporting is included on page 42 of this form 10-K.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended December 31, 2012 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, 2012. 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, 2012.

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 400 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, 2012.

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

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, 2012.

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, 2012.

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, 2012.

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).
3.3	Articles of Amendment to Articles of Incorporation of Ultra Petroleum Corp. (incorporated by reference to Exhibit 3.3 of the Company's Report on Form 10-K/A for the period ended December 31, 2005)
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).
4.2	Form 8-A filed with the Securities and Exchange Commission on July 23, 2007.
10.1	Credit Agreement dated as of October 6, 2011 among Ultra Resources, Inc., JPMorgan Chase Bank, N.A. as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 of the Company's Report on Form 8-K filed on October 11, 2011).
10.2	Share Purchase Agreement dated September 26, 2007 between UP Energy Corporation and SPC E&P (China) Pte. Ltd. (incorporated by reference to Exhibit 10.1 of the Company's Report on Form 8-K filed on September 26, 2007).
10.3	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).
10.4	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).
10.5	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).
10.6	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).
10.7	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).
10.8	Employment Agreement between Ultra Petroleum Corp. and Michael D. Watford dated August 6, 2007 (incorporated by reference from Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q for the period ended June 30, 2007).
10.9	Master Note Purchase Agreement dated March 6, 2008 (incorporated by reference to Exhibit 10.1 of the Company's Report on Form 8-K filed on March 6, 2008).
10.10	First Supplement dated March 5, 2009 to Master Note Purchase Agreement dated March 6, 2008 (incorporated by reference to Exhibit 10.1 of the Company's Report on Form 8-K filed on March 5, 2009).

Exhibit Number	Description
10.11	Second Supplement dated January 28, 2010 to Master Note Purchase Agreement dated March 6, 2008 (incorporated by reference to Exhibit 10.1 of the Company's Report on Form 8-K filed on January 28, 2010).
10.12	Third Supplement dated October 12, 2010 to Master Note Purchase Agreement dated March 6, 2008 (incorporated by reference to Exhibit 10.1 of the Company's Report on Form 8-K filed on October 12, 2010).
10.13	Sale and Purchase Agreement dated December 18, 2009 between Ultra Resources, Inc. and NCL Appalachian Partners, L.P., Locin Oil Corporation, Lyons Petroleum Reserves, Inc., MC Reserves, Inc., (incorporated by reference to Exhibit 1.1 of the Company's Report on Form 8-K filed on December 23, 2009).
*10.14	Sale and Purchase Agreement dated December 7, 2012 between Ultra Wyoming, Inc. and Pinedale Corridor, LP and First Amendment to Sale and Purchase Agreement dated December 12, 2012 between Ultra Wyoming, Inc. and Pinedale Corridor, LP.
*21.1	Subsidiaries of the Company.
*23.1	Consent of Netherland, Sewell & Associates, Inc.
*23.2	Consent of Ernst & Young LLP.
*31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
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*99.1	Reserve Report Summary prepared by Netherland, Sewell & Associates, Inc. as of December 31, 2012.
*101.INS	XBRL Instance Document
*101.SCH	XBRL Taxonomy Extension Schema Document
*101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
*101.LAB	XBRL Taxonomy Extension Label Linkbase Document
*101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
*101.DEF	XBRL Taxonomy Extension Definition

* Filed herewith.

SIGNATURES

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

ULTRA PETROLEUM CORP.

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

Date: February 20, 2013

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

Signature	***Title***	***Date***
/s/ Michael D. Watford Michael D. Watford	Chairman of the Board, Chief Executive Officer, and President (principal executive officer)	February 20, 2013
/s/ Marshall D. Smith Marshall D. Smith	Senior Vice President and Chief Financial Officer (principal financial officer)	February 20, 2013
/s/ Garland R. Shaw Garland R. Shaw	Corporate Controller (principal accounting officer)	February 20, 2013
/s/ W. Charles Helton W. Charles Helton	Director	February 20, 2013
/s/ Stephen J. McDaniel Stephen J. McDaniel	Director	February 20, 2013
/s/ Roger A. Brown Roger A. Brown	Director	February 20, 2013
/s/ Michael J. Keeffe Michael J. Keeffe	Director	February 20, 2013

EXHIBIT INDEX

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