US ENERGY CORP
Form 10-K
March 14, 2011

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

(Mark One)

þ Annual report pursuant to section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year Ended December 31, 2010

¨ 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 000-6814

U.S. ENERGY CORP.
(Exact Name of Company as Specified in its Charter)

Wyoming (State or other jurisdiction of incorporation or organization)	83-0205516 (I.R.S. Employer Identification No.)
877 North 8th West, Riverton, WY (Address of principal executive offices)	82501 (Zip Code)
Registrant's telephone number, including area code:	(307) 856-9271

Securities registered pursuant to Section 12(b) of the Act:
None
Securities registered pursuant to Section 12(g) of the Act:
Common Stock, $0.01 par value
(Title of Class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.YES ¨ NO þ

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 þ

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 Company was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.YES þ NO ¨

Indicate by check mark if disclosure of delinquent filers, pursuant to Item 405 of Regulation S-K is not contained herein and will not be contained, to the best of the 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 þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of “accelerated filer and large accelerated filer” in Rule 12b-2 of the Exchange Act.

Large accelerated filer ¨ Accelerated filer þ Non-accelerated filer ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).YES ¨ NO þ

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and ask price of such common equity, as of the last business day of the registrant’s most recently completed second fiscal quarter (June 30, 2010): $121,356,000.

Class	Outstanding at March 11, 2011
Common stock, $.01 par value	27,196,495

Documents incorporated by reference: None.

TABLE OF CONTENTS

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

The information discussed in this Annual Report includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 (the “Securities Act”) and Section 21E of the Securities Exchange Act of 1934 (the “Exchange Act”). All statements, other than statements of historical facts, are forward-looking statements. Examples of such statements in this Annual Report concern planned capital expenditures for oil and gas exploration; payment or amount of dividends on our common stock in the future; continued earnings swings; cash expected to be available for continued work programs; recovered volumes and values of oil and gas approximating third-party estimates of oil and gas reserves; anticipated increases in oil and gas production; drilling and completion activities in the Williston Basin and other areas; timing for drilling of additional wells; expected spacing for wells to be drilled with our industry partner Brigham Exploration Company in the Bakken/Three Forks formations; and expected well spacing for wells to be drilled with our other industry partners Houston Energy, Southern Resources; PetroQuest Energy, Cirque Resources LP, WR Production Company, Crimson Exploration and Zavanna.

Additional forward-looking statements in this Annual Report related to when payout may be reached for the wells drilled in 2010 with Brigham; the number of locations for wells that may be available for drilling with any of our other industry partners; expected working and net revenue interests, and costs of wells, for the drilling programs with any of our partners; actual decline rates for producing wells in the Bakken/Three Forks formations; submission of a Plan of Operations to the U.S. Forest Service and approval of such Plan in connection with the Mt. Emmons project and the expected length of time to permit and develop the Mt. Emmons project; expected time to receive a return on investment from the geothermal prospects; future cash flows and borrowings; pursuit of potential acquisition opportunities; anticipated business activities in the Gillette, Wyoming area and their impact on our Gillette, Wyoming multi-family housing complex; our expected financial position; and other plans and objectives for future operations.

These forward-looking statements are identified by their use of terms and phrases such as “may,” “expect,” “estimate,” “project,” “plan,” “believe,” “intend,” “achievable,” “anticipate,” “will,” “continue,” “potential,” “should,” “could,” and si phrases. Though we believe that the expectations reflected in these statements are reasonable, they do involve certain assumptions, risks and uncertainties. Results could differ materially from those anticipated in these statements as a result of certain factors, including, among others:

For oil and gas:

- having sufficient cash flow from operations and/or other sources to fully develop our undeveloped acreage positions;

- volatility in oil and natural gas prices, including potential depressed natural gas prices and/or declines in oil prices, which would have a negative impact on operating cash flow and could require ceiling test write-downs on our oil and gas assets;

    - the possibility that the oil and gas industry may be subject to new adverse regulatory or legislative actions (including changes to existing tax rules and regulations and changes in environmental regulation);

- the general risks of exploration and development activities, including the failure to find oil and natural gas in sufficient commercial quantities to provide a reasonable expectation of a return on investment;

-5-

- future oil and natural gas production rates, and/or the ultimate recoverability of reserves, falling below estimates;
- the ability to replace oil and natural gas reserves as they deplete from production;
- environmental risks;
- availability of pipeline capacity and other means of transporting crude oil and natural gas production; and
- competition in leasing new acreage and for drilling programs with operating companies, resulting in less favorable terms.

For the molybdenum property:

- the ability to obtain permits required to initiate mining and processing operations, and Thompson Creek Metals Company USA's continued participation as operator of the property; and
- completion of a feasibility study based on a comprehensive mine plan, which indicates that the property warrants construction and operation of mine and processing facilities, taking into account projected capital expenditures and operating costs in the context of molybdenum price trends.
- we are responsible for the operating costs of the water treatment plant until such time as Thompson Creek makes their election to own a percentage of the property at which time the costs will be split proportionately by percentage of ownership.

For real estate:

- failure of energy-related business activities in the Gillette, Wyoming area to support sufficient demand for apartments for us to realize a return on the investment.
- during 2011 we determined that we would finance and sell the multifamily housing project in Gillette, Wyoming. With the proceeds from the property we plan on furthering our oil and gas business. The selling price may not meet our expectations.

For geothermal activities:

- the ability to acquire additional Bureau of Land Management and/or other acreage positions in targeted prospect areas, obtain required permits to explore the acreage, drill development wells to establish commercial geothermal resources, and the ability of Standard Steam Trust LLC ("SST") to access third-party capital to reduce reliance on capital calls to its members (including U.S. Energy Corp.) for continued operations. We have notified SST that we do not intend to fund any cash calls which will result in a dilution of our ownership of SST.

Finally, our future results will depend upon various other risks and uncertainties, including, but not limited to, those detailed in the section entitled "Risk Factors" in this Annual Report. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements made above and elsewhere in this Annual Report. Other than as required under securities laws, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations, or otherwise.

-6-

PART I

Item 1 – Business

Overview

U.S. Energy Corp. ("U.S. Energy" or "We"), a Wyoming corporation organized in 1966, acquires and develops oil and gas and other mineral properties. We are continuing to invest aggressively by participating (through passive non-operating investments) in oil and gas plays with industry partners, and, in 2011, by acting as operator for selected properties.

We are maintaining steady progress with our partner, Thompson Creek Metals Company (USA), in the long-term development of the Mt. Emmons molybdenum property in west central Colorado. A multifamily apartment project serving the residential market in Gillette, Wyoming was completed in 2008, and it is generating positive cash flow; we do not intend to make more investments in the real estate housing sector and anticipate financing or selling the multifamily apartment project.

Industry Segments/Principal Products

At December 31, 2010, we have three operating segments: Oil and gas, real estate, and minerals (including geothermal).

Office Location and Website

Principal executive offices are located at 877 North 8th West, Riverton, Wyoming 82501, telephone 307-856-9271.

Our website is www.usnrg.com. We make available on this website, through a direct link to the Securities and Exchange Commission's website at http://www.sec.gov, free of charge, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements and Forms 3, 4 and 5 for stock ownership by directors and executive officers. You may also find information related to our corporate governance, board committees and code of ethics on our website. Our website and the information contained on or connected to our website is not incorporated by reference herein and our web address is included only for textual reference to the SEC filings.

Business

Oil and Gas

At December 31, 2010:

- Estimated proved reserves of 1,954,941 BOE (79% oil, 18% natural gas and 3% plant products), $44.7 million standardized measure and $52.1 million PV10, representing increases of 80%, 123%, and 102% over the 2009 reserves, standardized measure and PV10, respectively.
- Gross and net leases of 89,496 and 29,370 acres. At March 1, 2011, gross and net leases covered 97,221 and 33,213 acres.
- Seventeen gross (6.38 net) producing wells (19 and 6.71 at March 1, 2011).
- 1,230 BOE/D average for 2010 (1,051 BOE/D at March 1, 2011).

- Exploration and development agreements with eight industry partners and a wholly-owned Bakken/Three Forks acreage play (five partners and no acreage play in 2009). At March 1, 2011, we added another agreement (with Crimson Exploration, Inc.) for a total of nine partners.

PV10 (present value before taxes (discounted at ten percent)) is widely used in the oil and gas industry, and is followed by institutional investors and professional analysts to compare companies. However, PV10 data is not an alternative to the standardized measure of discounted future net cash flows, which is calculated under GAAP and includes the effects of income taxes. The following table reconciles PV10 to the Standardized Measure of Discounted Future Net Cash Flows, which are presented in Note G to the Company's Consolidated Financial Statements.

	(In thousands) At December 31,		
	2010	2009	2008
Standardized measure of discounted net cash flows	$ 44,653	$ 19,984	$ 3,318
Future income tax expense (discounted)	7,420	5,776	1,993
PV-10	$ 52,073	$ 25,760	$ 5,311

Activities with Operating Partners in Oil and Gas

The Company holds a geographically diverse portfolio of oil weighted prospects in varying stages of exploration and development, of which a majority of the properties are structured with eight different operating partners (nine at March 1, 2011). Prospect stages range from exploration and completion work, leasing activities (some with current partners to enlarge the land base, some for our own account), and seismic and other early stage science to identify drilling prospects (some with current partners, some for our own account).

A number of the programs were identified and structured in house. Each of the operators for the principal prospects has a substantial technical staff. We believe that these arrangements allow us to deliver value to shareholders without having to build the full staff of geologists, engineers and land personnel needed to work in diverse environments, such as deep Gulf Coast gas formations (PetroQuest), horizontal drilling in North Dakota (Brigham and Zavanna) and South Texas (Crimson Exploration) as well as conventional drilling in California's San Joaquin Basin.

We do intend to increase our technical staff (a landman and petroleum engineer) to be in position to operate selected properties we acquire on our own such as in Colorado and Montana (see "Operated Oil and Gas Activities"). However, consistent with industry practice with smaller independent companies, we still would utilize specialized consultants with local expertise as needed.

Existing oil and gas projects with operating partners are in these areas:

Williston Basin

With Brigham Exploration Company. On August 24, 2009, we entered into a Drilling Participation Agreement (the "DPA") with a wholly-owned subsidiary of Brigham Exploration Company. The DPA provides for U.S. Energy and Brigham to jointly explore for oil and gas in up to 19,200 gross acres in a portion of Brigham's Rough Rider prospect in Williams and McKenzie Counties, North Dakota.

Under our agreement with Brigham, we earned working interests, out of Brigham's interests, in fifteen 1,280-acre spacing units in Brigham's Rough Rider project area, which is located in Williams and McKenzie Counties, North Dakota, by participating in the drilling of one initial well on each unit of acreage. Accordingly, we have earned the rights to drill up to 30 gross wells in the Bakken formation and an additional 30 gross wells in the Three Forks formation, for a total of 60 gross wells, based on current spacing rules in North Dakota. If the spacing is ultimately increased to four wells per 1,280 acre spacing unit, the potential number of drilling locations could increase to 120 gross wells.

The leases in the units are a combination of fee and state leases. In some areas, the rights may be depth limited to the Bakken and the upper part of the Three Fork formations, due to leases obtained by Brigham from third parties, while other leases may have rights to all depths. Working interests earned vary according to Brigham's initial working interest, after-payout provisions and the provisions governing each stage of the program. At our current projected drilling rate, we expect that it will take four to six years to drill all of the wells on these units.

Our earn-in rights were staged in three groups of units, and were earned upon paying our share of all drilling and completion, or plugging and abandonment costs (if applicable), for all the initial wells (one for each unit) in each group. The numbers of initial wells (and units in the groups) consist of: Six in the First Group; four in the Second Group; and five in the Third Group. For information on the wells drilled through the date this Annual Report was filed, see "Item 2 – Properties – Oil and Natural Gas" below. At the date this Annual Report was filed, we have drilled all 15 wells in the initial phase of the DPA and have completed 12 wells, and are planning on drilling four to six additional (infill) gross wells in 2011.

Brigham is the operator for all the units covered by the DPA, and is compensated for services pursuant to an industry standard operating agreement, except that the customary non-consent provisions have been revised as to the drilling of subsequent wells (see below).

First Group: We earned 65% of Brigham's initial working interest in six 1,280 acre units; our working interest ranges from 61.46% to 29.58% (48.55% to 23.80% net revenue interest ("NRI")), for an average 49.54% working interest.

When we have received production revenues (less property and production taxes) from all six of the initial wells in this First Group, equal to our costs on a pooled basis ("Pooled Payout"), our working interest will be reduced to 42.25% of Brigham's initial working interest in the initial wells, and the NRI will decrease to a range of 31.56% to 15.47%, for an average 25.45% NRI. At December 31, 2010, we projected Pooled Payout for this First Group would occur in the second or third quarter of 2011. Subsequent to December 31, 2010, we have experienced significant workover expense related to one of the six wells, which will delay the Pooled Payout.

U.S. Energy earned 36% of Brigham's initial working interest to all the acreage in the applicable unit. Brigham will have no back in rights on any subsequent drilling locations in these units (or in any of the units we earned in the Second and Third Groups). All working interest ownership in each initial well, and all the subsequent wells, will be subject to proportionate reduction for third party lease hold rights. At December 31, 2010, three subsequent wells (two producing, one in completion) had been drilled in the First Group.

Second Group: In 2010, we participated in the drilling and completion of the four wells in the Second Group. Brigham gave us notice that it would be taking 50% of the working interest available to it, and we elected to take the remaining 50% of the working interest available to Brigham. The four wells were producing in 2010; our working interest ranges from 48.03% to 21.02% (NRIs of 37.80% to 16.29%).

-9-

We have earned working interest rights in all the acreage in these four units. For future wells drilled in these units, we will hold 36% of Brigham's initial working interest (without back in rights), subject to proportionate reduction for third party lease hold rights. After Pooled Payout on the Second Group's four wells, we will assign to Brigham 35% of our working interest in the initial wells in each spacing unit, and the NRI will decrease to a range of 24.26% to 10.61%. We anticipate Pooled Payout for the Second Group will be reached in third or fourth quarter 2012.

Third Group: On January 11, 2010, Brigham gave us notice that it would be taking 50% of the working interest available to it. In accordance with the DPA, we elected to take the remaining 50% of the working interest available to Brigham. All five wells in this group were drilled or being drilled at December 31, 2010; at December 31, 2010, one was producing, one was drilling, one was completing, and two were awaiting completion work. Working (and net revenue) interests range from 41.76% (32.96% NRI) to 20.01% (15.81% NRI).

We have earned 36% of Brigham's initial working interest in all the acreage in the units in this Third Group (which will not be subject to back in rights), proportionately reduced for third party lease hold rights. After payout on a per initial well basis ("Unpooled Payout"), we will assign 27.7% of our working interest in each initial well to Brigham, resulting in NRIs of 23.83% to 11.49%). We expect Unpooled Payout to be reached on these initial wells in 2013 through 2014.

Non-Participation in Subsequent Wells. Under the form of operating agreement which governs operations for each of the 15 units, after the applicable initial well, we will have the right to elect not to participate in the drilling or completion in subsequent wells proposed to be drilled in a unit. If U.S. Energy or Brigham should make an election not to participate, the non-participating party will assign all its rights in the proposed well to the participating entity for no consideration. However, our working interest rights in all acreage remaining in the unit would not be affected by the assignment.

With Zavanna, LLC. In December 2010, we signed two agreements with Zavanna, LLC (a private oil and gas company based in Denver, Colorado), and other parties, and paid $10,987,000 cash, to acquire, initially (see below), a 35% working interest out of Zavanna's working interests in oil and gas leases covering approximately 6,050 net acres in McKenzie County, North Dakota. Net revenue interests are expected to be in the range of 28% to 26.95%, proportionately reduced depending on Zavanna's actual WI%.

The acreage is in two parcels – the Yellowstone Prospect and the SE HR Prospect. We expect this program will result in 31 gross 1,280 acre spacing units (with various working interests of up to 35%), with the potential of 124 gross Bakken and 124 gross Three Forks wells.

In December 2010, we committed to the drilling of one initial horizontal test wells into the Bakken Formation and paid an advance of $1,433,000 for drilling costs on an initial well in the Yellowstone Prospect which began drilling in January 2011 and reached total depth in February 2011. A second well spud in February 2011. A third well (which will be the initial well on the SE HR Prospect), is expected to begin drilling in second quarter 2011.

Our interests in all the acreage is subject to reduction by operation of a 30% reversionary working interest in the separate acreage packages under each agreement. On the earlier of 36 months after spudding each initial test well (the "Project Payout Period"), or reaching "Project Payout," our 35% working interest will be reduced to 24.5% (with the NRI % also being proportionately reduced). Project Payout is that point in time when we have received proceeds from the sale of production (or from sale of all or part of the acreage to third parties) equal to 130% of: the $10,987,000 (paid on execution of the

-10-

agreements), plus all drilling and completion costs (including dry hole costs) and surface gathering facilities, for all wells drilled on the acreage (and on any additional acreage acquired in the two Areas of Mutual Interest contemplated by the agreements), referred to as the "Project Payout Properties."

However, if Project Payout does not occur within the 36 month Project Payout Period, the reduction due to operation of the reversionary working interest will take effect on all acreage other than the Project Payout Properties, i.e., that acreage in which wells not have commenced drilling (including all infill locations in drilling units where the Project Payout Properties are located, and the interest in all subsequent operations thereon). After expiration of the Project Payout Period, all costs and expenses related to the Project Payout Properties will continue to be included in the Project Payout calculation until Project Payout occurs.

With Crimson Exploration Inc. On February 22, 2011 USE entered into a participation agreement with Crimson Exploration Inc. ("Crimson") to acquire a 30% working interest in an oil prospect and associated leases located in Zavala County, Texas.

Under the terms of the agreement, USE will earn a 30% working interest (22.5% net revenue interest) in approximately 4,675 gross contiguous acres (1,402.5 net mineral acres) through a combination of a cash payment and commitment well carry. All future drilling and leasing will be on a heads up basis. For competitive reasons, the financial terms of the transaction will not be disclosed at this time.

The prospect is an Eagle Ford shale oil window target in Zavala County, Texas. Crimson will operate and tentatively plans to spud the first well in the area during the second quarter of this year. The well is planned to be drilled to a total drilling depth of approximately 12,500 feet (~6,000 ft. vertical, ~6,500 ft. horizontal), and to be completed with 14 fracture stimulation stages.

Texas and Louisiana

With PetroQuest Energy, Inc. Five wells have been drilled in coastal Louisiana with PetroQuest (NYSE: PQ). Three dry holes were plugged and abandoned and two wells are producing (both wells produce natural gas and oil); our working interests in the producers is (a) 14% (10.46% NRI before payout (9.76% NRI after payout), and (b) 53.33% (36% NRI). We expect to drill more wells with PetroQuest in 2011 but none have been signed up as of the date this Annual Report is filed. At payout on one of the producing wells (plus 6% annual interest), we will assign 15% of our working interest to a third-party consultant, and an additional 5% of our working interest at 200% of payout. Payout was reached for this well in January 2011.

With Yuma Exploration and Production Company, Inc. We have a working interest in a seismic, lease acquisition and drilling program with Yuma (a private company) that covers approximately 88,320 acres in South Louisiana. Seismic data collection has been completed and is being evaluated. This lease/option program continues through April 27, 2012; in 2010, one well was drilled and watered out and one was in completion at December 31, 2010 (working interests (NRI) in these wells is (a) 4.79% (3.62% NRI, decreasing to 3.17% NRI after payout), and (b) 4.79% (3.78% NRI, decreasing to 3.31% after payout – see below). We expect that Yuma will recommend drilling at least six more prospects in 2011. Participants will have the opportunity to opt in or out of any prospect leasing program, and the initial well in each prospect. Each prospect will have a separate operating agreement designating Yuma as operator. It is expected that the program will yield multiple oil and natural gas prospects, with exploration activities continuing for a number of years.

-11-

The Company holds a 4.79% working interest, Yuma owns an approximate 48% working interest, and the balance (approximately 47.21%) is held by third parties. At payout we will assign to a third party consultant 12.5% of our working interest in each producing well. For their working interests, the participants (other than Yuma) have paid 80% of the initial seismic, overhead and some land costs ($1.2 million by USE), and Yuma is paying 20%. All land and exploration costs going forward are to be paid according to the working interest percentages.

With Houston Energy L.P. In 2009 and 2010, we participated with Houston Energy in drilling two producing wells and three dry holes; in the producers (drilled in 2009), we own a working interest of (a) 8.50% (6.23% NRI after payout, reducing to 4.91% NRI after payout for a consultant's back in interest); and (b) 25% (17.63% NRI after payout, reducing to 15.42% NRI after payout for a consultant's back in interest).

We entered into two new agreements with Houston Energy in 2010:

NE Delta Farms Prospect Participation Agreement (Lafourche and Jefferson Parishes, Louisiana)

By paying $60,000 (our share of Houston Energy's lease acquisition costs), we acquired a working interest before the casing point decision ("CPD") is made (to complete or abandon a well), in all the prospects (approximately 496 gross acres (123 net mineral acres), we acquired a 33% working interest before the CPD on each prospect (24.75% after CPD (18.19% NRI). An affiliate of Houston Energy, and the 3D seismic company involved in the prospect, will receive a total 4.5% ORRI on the leases in this program.

Subsequent to year end, this well was determined to be non-productive and will be plugged and abandoned.

Gaines County, Texas Participation Agreement (Five Prospects – GTY Permian Basin)

We paid our share ($310,000) of Houston Energy's lease acquisition and related costs, to acquire a 13.33% working interest (10.00% after CPD), representing an estimated 7.9% NRI. These prospects are burdened by a 3.0% ORRI in favor of an affiliate of Houston Energy. Two non productive wells were drilled on these prospects in 2010 ($529,000 net to USE). Up to 3 additional wells could be drilled under this agreement in 2011.

With Southern Resources Company This agreement covers a 13.5% working interest (9.86% NRI) in 1,282 gross (173 net) acres in Hardin County, Texas (approximately midway between Houston and Beaumont). If we elect to proceed by participating in the initial test well (and paying our $135,000 of seismic, land acquisition and legal costs), we will earn our working interest in all the acreage, and the seller will have an 18.75% carried working interest (to the CPD) in the initial test well, and a 12.5% carried working interest in the second test well (to the CPD). Subsequent wells will be paid proportionate to the all parties' working interests. Mueller Exploration, Inc. will operate all wells. If the initial test well is not spudded by June 1, 2011, the agreement will terminate.

With WR Production Company. In March 2010, we signed an agreement with WR Production, LLC to purchase a 10% working interest (7.4% average NRI) in 898 gross (90 net) acres. We have paid $188,000 for prospect and leasehold costs to the date of the agreement. Initial well drilling costs will include 3.33% of WP's working interest share.

California

With Cirque Resources LP (Kern County, California) Under an October 2010 agreement with Cirque Resources LP ("Cirque") (a private exploration and development company based in Denver, Colorado), we paid $2,498,000 to Cirque to purchase a 40% working interest (32% NRI) in Cirque's leases on 6,120 net mineral acres (2,448 acres net to our interest), in the San Joaquin Basin. Of the amount paid, $1,620,000 is an advance against our 40% working interest for the initial well, including 33% of Cirque's 60% working interest share for the well. Cirque's lease assignments are held in escrow, until the end of the well's drilling phase; if we have paid all the drilling costs (ours and Cirque's carry), the assignments will be recorded and released to us.

Completion and all other costs and expenses on the initial well and for all subsequent wells and any midstream projects (gathering, compressors, and processing/treatment facilities) will be paid by participants in proportion to their working interests. We are estimating our share of total completion costs for the initial well to be in the range of $640,000. Cirque is the operator for all operations on the prospect.

The primary target in the Moose Prospect is the Miocene; the initial well will be drilled to approximately 13,000 feet to test the Stevens Sands in a stratigraphic trap on the flank of the Elk Hills anticline. Current spacing rules and current interpretation of geological data indicate that up to 40 additional locations could be drilled. Additional seismic work including re-analysis of existing 2D and modeling into 3D may be undertaken to further scientific evaluations.

Operated Oil and Gas Activities

Montana Acreage Play

During 2010, U.S. Energy acquired 100% working interest in approximately 16,560 gross mineral acres (11,627 net mineral acres) of undeveloped leasehold interests, fee mineral interest and operating rights in oil and gas leases in Northeast Montana for approximately $809,000. In addition to landowner royalties which range from 12.5% to 15%, some of the leases are burdened with Overriding Royalty Interests ("ORRI") in favor of the seller as follows:

2% ORRI on leases that have a total royalty interest ("RI") of 12.5 or less; 1.0% ORRI on leases that have a total RI greater than 12.5% but less than or equal to 15%; 1% ORRI on leases that have a RI greater than 15% but less than or equal to 16.67 %; 0.5% ORRI on leases that have a RI greater than 16.67% but less than or equal to 19%.

We can buy back the ORRIs at any time on a sliding scale of from $60 per net mineral acre where the total royalty interest (exclusive of the ORRIs) is 12.5% or less, down to $15 where the total royalty interest is more than 16.67% but less than or equal to 19%.

Leasing and drilling activities by other companies looking to find Bakken Shale and Three Forks production in the Northeast part of Montana increased significantly in 2010. We are holding our acreage for future exploration and development, and may enlist the participation of industry partners at some point in the future. USE is the operator. No arrangements with other companies have been negotiated to date, and no wells have been drilled on our acreage.

Apache and Buffalo Creek Prospects (Southeast Colorado)

On January 26, 2011 we paid $87,000 to buy an 80% working interest in leases covering 2,994 net mineral acres in southeast Colorado, for their joint development (U.S. Energy as operator) with the sellers, who retained 20% of the working interest (and, only as to the acreage in the Buffalo Creek acreage, the positive difference between an 80% NRI and landowners' royalties). We can buy back these ORRIs for $50,000 if the initial production on the initial well is 100 or less barrels of oil per day, and $100,000 if initial production is more than 100 barrels per day.

In addition, we will pay all the drilling costs of the initial well, to the casing point; if the sellers do not elect to participate in completion, the sellers will forfeit to USE their 20% working interest in the 160 acres associated with the well. There will be only one "initial well" to which this provision applies.

Additional leases may be acquired in the area; if acquired from the sellers, the price will be at their cost, without ORRIs or carried working interest. USE is the operator.

Going Forward

In 2011 and beyond, U.S. Energy intends to seek additional opportunities in the oil and natural gas sector, including further acquisition of assets, participation with current and new industry partners in their exploration and development projects, acquisition of operating companies, and the purchase and exploration of new acreage positions.

Credit Facility

On July 30, 2010, we established a credit facility to increase access to capital. This arrangement is available only for our oil and gas segment, and provides us with the flexibility of investing and funding drilling/completion work without having to sell assets. We expect significant borrowings to be serviced with cash flow, and/or equity financing.

The Senior Secured Revolving Credit Facility (the "Facility") allows us to borrow up to $75 million from a syndicate of banks, financial institutions and other entities, including BNP Paribas ("BNPP," and, together with other members of the syndicate, the "Lenders"). BNPP also is the administrative agent for the Facility, which is governed by the following documents: Credit Agreement; Mortgage, Deed of Trust, Assignment of As-Extracted Collateral, Security Agreement, Fixture Filing and Financing Statement (the "Mortgage"); and Guaranty and Pledge Agreement (the "Guaranty"), which are referred to below together as the "Facility Documents." The following summarizes the principal provisions of the Facility as set forth in the Facility Documents, which are filed as exhibits to this Annual Report.

We formed a wholly-owned subsidiary Energy One LLC ("Energy One"), which will be the borrower under the Facility. We assigned to Energy One all of our right, title and interest in and to current and acquired-in-the-future oil and gas properties and equipment related thereto, rights under various operating agreements, proceeds from sale of production and from sale or other disposition (including without limitation farm-ins and farm-outs). We also have unconditionally and irrevocably guaranteed Energy One's performance of its obligations under the Credit Agreement, including without limitation Energy One's payment of all borrowings and related fees thereunder.

From time to time until expiration of the Facility (July 30, 2014), if Energy One is in compliance with the Facility Documents, Energy One may borrow, pay, and re-borrow from the Lenders, up to an amount equal to the Borrowing Base (initially established at $12 million, currently $18.5 million). Energy One borrowed $3.0 million under this Credit Facility on February 18, 2011. Proceeds from the borrowing were used to purchase an interest in Crimson Exploration's Eagle Ford shale oil prospect in Zavala County, Texas.

The Borrowing Base will be determined semi-annually (more often at the request of BNPP or Energy One), with updated reserve reports prepared by the Company's independent consulting engineers. Any proposed increase in the Borrowing Base will require approval by all Lenders, and any proposed Borrowing Base decrease will require approval by Lenders holding not less than two-thirds of outstanding loans and loan commitments.

Interest will be payable quarterly at the greater of the Prime Rate, the Federal Funds Effective Rate (plus 0.5%), and the adjusted LIBO for the three prior months (plus 1%), plus, in any event, an additional 1.25% to 3.25%, depending on the amount of the loan relative to the Borrowing Base. Interest rates on outstanding loans are adjustable each day by BNPP as administrative agent. Energy One may prepay principal at any time without premium or penalty, but all outstanding principal will be due on July 30, 2014. If there is a decrease in the Borrowing Base, outstanding principal will be due over the five months following the determination.

Energy One is required to comply with customary affirmative covenants, and with negative covenants. The principal negative covenants (measured at various times as provided in the Credit Agreement) are not permitting (i) Interest Coverage Ratio (Interest Expense to EBITDAX) to be less than 3.0 to 1; (ii) Total Debt to EBITDAX to be greater than 3.5 to 1; and (iii) Current Ratio (current assets plus unused lender commitments under the Borrowing Base) to be a minimum of 1.0 to 1.0. EBITDAX is defined in the Credit Agreement as Consolidated Net Income, plus non-cash charges.

Madison Williams and Company

Since March 2009, Madison Williams and Company ("MWC"), has helped us identify and structure three of the principal drilling programs (Brigham, Zavanna and Crimson), through its relationships with these operators. MWC also assisted in setting up the BNP Paribas credit facility. MWC is acting as our exclusive financial advisor in connection with the purchase or acquisition of oil and gas assets, including oil and gas companies, oil and gas working interests, and joint ventures or similar types of oil and gas ventures from entities that we have mutually agreed to approach regarding possible transactions. The firm also provides financial advisory and investment banking services.

In 2010 and 2009, we paid a total of $1,316,400 to MWC (and its predecessor, the principal capital markets business of SMH Capital, see below): $75,000 general advisory fees; $92,500 retainer fees; expense reimbursements of $70,600; and transaction fees of $1,078,300 related to negotiating and setting up the Credit Facility with BNP Paribas, and the Brigham and Zavanna deals. We will also be paying MWC a fee for the Crimson transaction which was closed in 2011.

The foregoing payments do not include MWC's services as lead underwriter and bookrunner for USE's $26.25 million public equity financing in fourth quarter 2009, which was governed by a separate agreement as well as an underwriting agreement for the financing. We anticipate that MWC will have the same role in future public financings.

-15-

MWC is a private management-owned investment banking firm; until late 2009, it was the principal capital markets business of SMH Capital, when it was spun out of Sanders Morris Harris Group. MWC has extensive experience in providing a broad range of services to the energy industry.

Activities other than Oil and Gas

Molybdenum

On August 19, 2008, U.S. Energy and Thompson Creek Metals Company USA ("TCM"), a Colorado corporation headquartered in Englewood, Colorado, entered into an Exploration, Development and Mine Operating Agreement for our Mount Emmons molybdenum property. TCM assigned the agreement to Mt. Emmons Moly Company, a Colorado corporation and wholly owned subsidiary of TCM effective September 11, 2008. Under the terms of the agreement TCM may acquire up to a 75% interest for $400 million (option payments of $6.5 million and project expenditures of $393.5 million).

The Agreement covers two distinct periods of time: The Option Period, during which TCM may exercise an option to acquire up to a 50% interest in Mount Emmons; and the Joint Venture Period, during which TCM will form a joint venture with us, and also have an option to acquire up to an additional 25% interest.

The Option Period:

Through December 31, 2010, TCM has paid us $500,000 (at the September 2008 closing), (not refundable), and $3 million for the $1.0 million option payments for 2009, 2010 and 2011. TCM has the continuing option to make three more $1 million annual payments.

The option is exercisable in two stages:

First Stage - For 15%. At TCM's election within 36 months of incurring a minimum of $15,000,000 in expenditures on or related to Mount Emmons, TCM may acquire an undivided working interest of 15% in Mount Emmons. TCM also must make the option payments, but each such payment will be credited against the required annual expenditure amount. Following is a table of the options and expenditures due from TCM through June 2011:

Option Payments and Expenditure Amounts, and Deadlines

$	500,000	Option Payment	At Closing*
$	2,000,000	Expenditures	December 31, 2008*
$	1,000,000	Option Payment	January 1, 2009**
$	4,000,000	Expenditures	December 31, 2009**
$	1,000,000	Option Payment	January 1, 2010**
$	4,000,000	Expenditures	December 31, 2010***
$	1,000,000		

		Option Payment	January 1, 2011***
$	1,500,000	Expenditures	June 30, 2011
$	15,000,000		

*	Paid in 2008
**	Paid in 2009
***	Paid in 2010

Costs to operate the water treatment plant at the property are being paid solely by us until TCM elects to exercise its option to own an interest in the property.

Second Stage - For an Additional 35%. If by July 31, 2018, TCM has incurred a total of at least $43,500,000 of expenditures (including amounts during the first stage) and paid us the total $6,500,000 of option payments (for a total of $50,000,000), TCM may elect to acquire an additional 35% (for a total of 50% after it exercised the first stage option for 15%). None of the interests acquired by TCM will be subject to any overriding royalties to us.

Upon failure by TCM to incur the required amount of expenditures by a deadline, or make an Option Payment to U.S. Energy, subject to the terms of the Agreement, the Agreement may be terminated without further obligation to us from TCM. TCM may terminate the Agreement at any time, but if earned and elected to accept, TCM will retain the interest earned and be responsible for that share of all costs and expenses related to Mount Emmons.

The Joint Venture Period; Joint Venture Terms:

Within six months of TCM's election to acquire the 50% interest, TCM, in its sole discretion, shall elect to form a Joint Venture and either: (i) participate on a 50%-50% basis with us, with each party to bear their own share of expenditures from formation date; or (ii) acquire up to an additional 25% interest in the project by paying 100% of all expenditures equal to $350 million (for a total of $400 million, including the $50 million to earn the 50% interest in the Second Stage of the Option Period), at which point the participation would be 75% TCM and 25% U.S. Energy. Provided however, if TCM makes expenditures of at least $70 million of the $350 million in expenditures and TCM decides not to fund the additional $280 million in expenditures, TCM will have earned an additional 2.5% (for a total of 52.5%). Thereafter, TCM will earn an incremental added percentage interest for each dollar it spends toward the total $350 million amount.

At any time before incurring the entire $350 million, TCM in its sole discretion, may determine to cease funding 100% of expenditures, in which event U.S. Energy and TCM then would share expenditures in accordance with their participation interests at that date. With certain exceptions, either party's interest is subject to dilution in the event of non-participation in funding the Joint Venture's budgets.

Management of the Property

TCM is Project Manager of the Mount Emmons Project. A four person Management Committee governs the projects' operations, with two representatives each from U.S. Energy and TCM. TCM will have the deciding vote in the event of a committee deadlock.

If and when Mount Emmons goes into production, TCM will purchase our share of the molybdic oxide produced at an average price as published in Platt's Metals Weekly price less a discount with a cap and a floor. The discount band will be adjusted every five years based upon the United States' gross domestic product.

Renewable Energy — Geothermal

At December 31, 2010 we owned a minority ownership interest, 22.8%, in a geothermal partnership, Standard Steam Trust, LLC ("SST").

In April 2010, SST sold two prospects to a global geothermal industry company, for $8.72 million cash. If the buyer constructs a power plant with more than 30 megawatts of generating capacity, additional cash will be paid to SST equal to $350,000 for each additional megawatt. Our investment in SST does not obligate us to fund any future cash calls. If we elect not to fund cash calls, we will suffer dilution. We have notified that we do not intend to fund any cash calls to the partners which will result in a dilution of our ownership of SST.

Real Estate

In 2008, we completed construction of a nine building, 216-unit multifamily apartment complex in Gillette, Wyoming at a total all-in cost of $24.5 million. The occupancy rate was 89% at December 31, 2010. The Company had an appraisal completed as of December 31, 2010 which valued the property at $21.0 million. An impairment of $1.5 million was therefore recorded at December 31, 2010 on the property. Although the property produces positive cash flow from its operations, the return from oil and gas investments is expected to yield a higher return. The Company therefore plans on selling this property in the future to continue growing its oil and gas business.

Item 1A - Risk Factors

The following risk factors should be carefully considered in evaluating the information in this Annual Report.

Risks Involving Our Business

Global Financial Stress and Credit Crisis.

The continuing Great Recession and concomitant credit crisis and related turmoil in the global financial system may have a material impact on our ability to finance the purchase and/or exploitation of oil and gas properties. The availability of credit to our industry partners may also affect their ability to generate new exploration and development prospects, to meet their obligations to us, and/or on their liquidity, which could result in operational delays or even their failure to make required payments. Additionally, volatility in oil prices, particularly a significant and sustained drop in current oil prices could have a negative impact on our financial position, results of operations, and cash flows.

Risks Related to Climate Change.

While the scope and timing of climate change is not determinate, the adoption of laws and regulations, and international accords to which the United States is a party, could affect our oil and natural gas business segment. The emergence of trends such as a worldwide increase in hybrid power motor vehicle sales, and/or decreased personal motor vehicle use by individuals, in response to perceived negative impacts on the climate from “greenhouse emissions,” could result in lower world-wide consumption of, and prices for, crude oil. Additionally, as part of state-level efforts to reduce these emissions, operating restrictions on emissions by drilling rigs and completion equipment could be enacted, leading to an increase in drilling and completion costs.

In January 2011, President Obama stated that his administration would request legislation reducing if not eliminating various “tax breaks” now available to the oil and gas exploration and production industry. The 2012 budget published in February 2011 proposes many of the same items for legislation that were in the 2011 budget, including proposals to terminate oil and gas company tax preferences, including repeals of expensing intangible drilling costs, passive loss limitations for working interests in oil and natural gas properties, percentage depletion for oil and natural gas wells, and increasing the amortization period for

geological and geophysical expenses to seven years. If such proposals were enacted substantially as proposed, our income from oil and natural gas investments would be decreased and additional capital likely would become more expensive and more difficult to obtain. Additional adverse impacts could flow from enactment of Federal legislation aimed directly at controlling and reducing emissions of greenhouse emissions. See also the next risk factor.

The adoption of climate change legislation could result in increased operating costs and reduced demand for oil and natural gas.

In June 2009, the U.S. House of Representatives approved adoption of the "American Clean Energy and Security Act of 2009," also known as the "Waxman-Markey cap-and-trade legislation" or ACESA. The purpose of ACESA was to control and reduce emissions of "greenhouse gases," or "GHGs," in the United States. GHGs are certain gases, including carbon dioxide and methane that may be contributing to warming of the Earth's atmosphere and other climatic changes. ACESA would establish an economy-wide cap on emissions of GHGs in the United States and would require an overall reduction in GHG emissions of 17% (from 2005 levels) by 2020, and by over 80% by 2050. Under ACESA, most sources of GHG emissions would be required to obtain GHG emission "allowances" corresponding to their annual emissions of GHGs. The number of emission allowances issued each year would decline as necessary to meet ACESA's overall emission reduction goals. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. The net effect of ACESA will be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas. The U.S. Senate began work on its own legislation for controlling and reducing emissions of GHGs in the United States, but the legislation stalled in 2010.

The U.S. Environmental Protection Agency is also separately undertaking a rulemaking process to determine whether GHGs will be designated as "pollutants" under the existing Federal Clean Air Act.

Though it is not predicted whether such legislation will be reintroduced and made law, or EPA rule making will be implemented, legislation and/or rule making along the lines previously contemplated would likely require us to incur increased operating costs, and could have an adverse effect on the oil and gas industry.

We will require funding in addition to working capital at December 31, 2010.

We were able to maintain adequate working capital in 2010 primarily through a December 2009 public offering of 5 million shares for $24.3 million of net proceeds. Working capital at December 31, 2010 was $11.1 million, an amount sufficient to continue substantial exploration and development work in oil and gas, but not enough to take full advantage of the opportunities we now have or be in position for new opportunities. We could spend up to $46 million in 2011 for work on existing programs.

Additionally, all of our partner agreements have customary industry non-consent provisions: If a well is proposed to be drilled or completed but a working interest owner doesn't participate, resulting revenues (which otherwise would go to the non-participant) flow to the participants until they receive from 200% to 300% of the capital they put up to cover the non-participant's share.

As a result, in order to be in position to avoid non-consent penalties, and make opportunistic investments in new assets, we will be evaluating various options to obtain additional capital, including loans through the Credit Facility, sale of equity and sale of the apartment complex in Gillette, Wyoming.

Beyond 2011, we may have capital needs from time to time in excess of funds on hand. The minerals business presents the opportunity for significant returns on investment, but achievement of such returns is subject to high risk. As examples:

- Initial results from one or more of the oil and gas programs could be marginal but warrant investing in more wells. Dry holes, over budget exploration costs, low commodity prices, or any combination of these factors, could result in production revenues below projections, thus adversely impacting cash expected to be available for continued work in a program, its ultimate returns falling below projections, and a reduction in cash for investment in other programs.

- We are paying the annual costs (approximately $1.8 million) to operate and maintain the water treatment plant at the Mount Emmons Project until such time as Thompson Creek Metals elects to acquire an interest. Thereafter, we would be responsible for paying our proportionate share of plant costs. Of greater potential significance, should Thompson Creek Metals elect to participate in the Mount Emmons Project up to the 75% level and expends $400 million on the property, thereafter we would be responsible for our 25% share of all costs, which could be very substantial.

These types of events could require a reassessment of priorities and therefore potential re-allocations of existing capital and mandate obtaining new capital.

Competition may limit our opportunities in the oil and gas business.

The oil and natural gas business is very competitive. We compete with many public and private exploration and development companies in finding investment opportunities. We also compete with oil and gas operators in acquiring acreage positions. Our principal competitors are small to mid-size companies with in-house petroleum exploration and drilling expertise. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. They may be willing and able to pay more for oil and natural gas properties than our financial resources permit, and may be able to define, evaluate, bid for and purchase a greater number of properties. In addition, there is substantial competition in the oil and natural gas industry for investment capital, and we may not be able to compete successfully in raising additional capital if needed.

Successful exploitation of the Williston Basin and the Eagle Ford Shale is subject to risks related to horizontal drilling and completion techniques.

Operations in the Williston Basin and the Eagle Ford Shale involve utilizing the latest drilling and completion techniques to generate the highest possible cumulative recoveries and therefore generate the highest possible returns. Risks that are encountered while drilling include, but are not limited to, landing the well bore in the desired drilling zone, staying in the zone while drilling horizontally through the shale formation, running casing the entire length of the well bore and being able to run tools and other equipment consistently through the horizontal well bore.

Completion risks include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools the entire length of the well bore during completion operations, and successfully cleaning out the well bore after completion of the final fracture stimulation stage. Ultimately, the success of these latest drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period.

-20-

The results of the drilling programs in the Williston Basin and the Eagle Ford Shale are subject to more uncertainties than drilling in more established formations in other areas.

Williston Basin

Although numerous wells have been drilled and completed in the Bakken and Three Forks formations in the Williston Basin, with horizontal wells and completion techniques that have proven to be successful in other shale formations, industry's drilling and production history in the formation generally remains somewhat limited. The ultimate success of these drilling and completion strategies and techniques will be better evaluated over time as more wells are drilled and longer term production profiles are established.

In addition, based on reported decline rates in these formations, estimated average monthly rates of production may decline by approximately 70% during the first twelve months of production. However, actual decline rates may be significantly different than expected. Due to the limited horizontal production data for the Bakken and Three Forks formations, drilling and production results are more uncertain than encountered in other formations and areas with histories. Good results from wells we have participated in may not be replicated in additional wells, even in the same drilling unit.

Through the date this Annual Report was filed, one of the wells we have drilled with Brigham was completed in the Three Forks Formation, and the rest have been completed in the Bakken Formation. Brigham (and other operators) have reported successful completion of Three Forks wells in other parts of the Williston Basin, The Three Forks, underlying the Bakken, is an unconventional carbonate formation (sand and porous rock) which is prospective for oil and gas. It is believed to be separate from the Bakken. However, the Three Forks has been explored to a lesser extent than the Bakken in many areas of the Basin, and its characteristics are not as well defined. Accordingly, we may encounter more uncertainty in drilling Three Forks wells with Brigham, compared with drilling Bakken wells.

The foregoing considerations also apply to our opportunities to drill the same formations with Zavanna.

Eagle Ford Shale

The Eagle Ford Shale, covering 14 counties in South Texas, is now a very active area for exploration and development, involving large companies (such as Shell, ConocoPhillips, and Chesapeake Energy) as well as a host of mid-size to small independents. However, like the Bakken, since the data base is still evolving, the Eagle Ford characteristics are not well defined and thus can present more uncertainty than more mature drilling areas.

Operating in less developed regions of the Williston Basin has risks that include, but are not limited to, securing access to takeaway capacity and securing access to equipment and service providers on a timely and cost effective basis, and some of the initial gas production is lost to flaring.

Access to adequate gathering systems or pipeline takeaway capacity is limited in the Williston Basin. In order to secure takeaway capacity, our operators may be forced to enter into arrangements that are not as favorable to operators in other areas. Additionally, access to equipment and service providers may not be available on a timely or cost effective basis, which could delay a drilling program.

As of the date this Annual Report was filed, all of the wells we have drilled with Brigham have produced oil and natural gas (generally an initial ratio of about 85% oil and 15% gas). Oil sales commence immediately after completion work is finished, but natural gas is flared (burned off) until the well can be hooked up to a transmission line. Installation of a gathering system can take from 90 to 120

-21-

days, or longer, depending on well location, weather conditions, and availability of service providers. As of the date this Annual Report was filed, all but 2 of our wells with Brigham are selling gas.

We may encounter the same operating issues in the drilling program with Zavanna.

We may not be able to drill wells on a substantial portion of our Williston Basin and Eagle Ford Shale acreage.

We may not be able to participate in all or even a substantial portion of the many locations we have earned through the Drilling Participation Agreement with Brigham, and available to us through the Zavanna program, or the drilling locations available in the Crimson Participation Agreement. The extent of our participation will depend on drilling and completion results, commodity prices, the availability and cost of capital relative to ongoing revenues from completed wells, and other factors.

Lower oil and natural gas prices may cause us to record ceiling limitation write-downs, which would reduce stockholders' equity.

We use the full cost method of accounting to account for our oil and natural gas investments. Accordingly, we capitalize the cost to acquire, explore for and develop these properties. Under full cost accounting rules, the net capitalized cost of oil and gas properties may not exceed a "ceiling limit" that is based upon the present value of estimated future net revenues from proved reserves, discounted at 10%, plus the lower of the cost or fair market value of unproved properties. If net capitalized costs exceed the ceiling limit, we must charge the amount of the excess to earnings (called a "ceiling limitation write-down"). The risk of a ceiling test write-down increases when oil and gas prices are depressed or if we have substantial downward revisions in estimated proved reserves.

Under the full cost method, all costs associated with the acquisition, exploration and development of oil and gas properties are capitalized and accumulated in a country-wide cost center. This includes any internal costs that are directly related to development and exploration activities, but does not include any costs related to production, general corporate overhead or similar activities. Proceeds received from disposals are credited against accumulated cost, except when the sale represents a significant disposal of reserves, in which case a gain or loss is recognized. The sum of net capitalized costs and estimated future development and dismantlement costs for each cost center is depleted on the equivalent unit-of-production method, based on proved oil and gas reserves. Excluded from amounts subject to depletion are costs associated with unevaluated properties.

Under the full cost method, net capitalized costs are limited to the lower of unamortized cost reduced by the related net deferred tax liability and asset retirement obligations or the cost center ceiling. The cost center ceiling is defined as the sum of (i) estimated future net revenue, discounted at 10% per annum, from proved reserves, based on unescalated costs, adjusted for contract provisions, any financial derivatives that hedge our oil and gas revenue and asset retirement obligations, and unescalated oil and gas prices during the period, (ii) the cost of properties not being amortized, and (iii) the lower of cost or market value of unproved properties included in the cost being amortized, less (iv) income tax effects related to tax assets directly attributable to the natural gas and crude oil properties. If the net book value reduced by the related net deferred income tax liability and asset retirement obligations exceeds the cost center ceiling limitation, a non-cash impairment charge is required in the period in which the impairment occurs.

Effective for years ending on and after December 31, 2009, the SEC amended the disclosure rules to require such revenue estimates to be based on the average price received during the 12-month period before the ending date of the period covered by the report, determined as an unweighted average of the

first-day-of-the-month price for each month within such period. Accordingly, our estimated future net revenues as of December 31, 2010 and 2009 are based on the monthly average price received during the full year period. For 2008, in accordance with SEC disclosure requirements previously in effect, estimated future net revenues (discounted at 10% per annum) from proved reserves were calculated based upon prices for oil and natural gas at December 31, 2008.

Full cost pool capitalized costs are amortized over the life of production of proven properties. Capitalized costs at December 31, 2010 and 2009, which were not included in the amortized cost pool, were $21.6 million and $5.4 million, respectively. These costs consist of wells in progress, costs for seismic analysis of potential drilling locations, as well as land costs, all related to unproved properties.

We perform a quarterly and annual ceiling test for each of our oil and gas cost centers (at December 31, 2010 and 2009, there was one such cost center (the United States)). The ceiling test incorporates assumptions regarding pricing and discount rates over which we have no influence in the determination of present value. In arriving at the ceiling test for the year ended December 31, 2010, we used $79.43 per barrel for oil and $4.376 per MMbtu for natural gas to compute the future cash flows of each of the producing properties at that date. The discount factor used was 10%.

Capitalized costs for oil and gas properties did not exceed the ceiling test limit in 2010. During 2009, we recorded a non-cash write down of $1.5 million. We may be required to recognize additional pre-tax non-cash impairment charges (write-downs) in future reporting periods depending on the results of oil and gas operations and/or market prices for oil, and to a lesser extent natural gas.

The Williston Basin oil price differential could have adverse impacts on our revenues.

Generally, crude oil produced from the Bakken formation in North Dakota is high quality (36 to 44 degrees API, which is comparable to West Texas Intermediate Crude). However, due to takeaway constraints, oil prices in the Williston Basin generally have been from $8.00 to $10.00 less than prices for other areas in the United States.

Drilling and completion costs for the wells we drill in the Williston Basin are comparable to other areas where there is no price differential. As a result of this reverse leverage effect, a significant prolonged downturn in oil prices on a national basis could result in a ceiling limitation write-down of the oil and gas properties we hold. Such a price downturn also could reduce cash flow from the Williston Basin properties, and adversely impact our ability to participate fully in drilling with Brigham and Zavanna.

Our business may be impacted by adverse commodity prices.

Since June, 2009, oil prices have ranged from a ten year high with a spot price of $133.88 per barrel, to $41.12 per barrel at December 31, 2008, to $74.47 at the end of 2009, to $91.38 at December 31, 2010. Global markets, in reaction to the Great Recession, and perceived upticks or downticks in future global supply, have caused these large fluctuations. The first quarter 2011 political changes in the Mideast may continue to propel oil prices to or beyond the highs experienced in late 2008, but drop if the “fear premium” fades. This could add to the risks associated with our hedging program (see the risk factor “The use of hedging arrangements in oil and gas production could result in financial losses or reduce income” below).

Natural gas prices are historically volatile, and reached a ten year high during July 2008 on the City Gate at $12.48 per thousand cubic feet of natural gas, then down to $6.24 per Mcf at December 31, 2009, and further down to $4.40 at December 30, 2010. Molybdenum prices have declined from a ten year high

-23-

of $38.00 per pound in June 2005 to a ten year low average price of $8.03 per pound in April 2009. The average price at December 31, 2010 was $16.60 per pound, compared to $11.50 per pound at year end 2009. Price stabilization or improvement in 2011 will be dependent on continued strong demand, but demand could weaken if industrial consumption sags due to economic constraints in key markets (particularly China and Southeast Asia). Significant oil price declines from December 31, 2010 would decrease anticipated revenues and could impair the carrying value of our producing properties.

We do not have independent reports on the value of some of the mineral properties.

We have not yet completed a feasibility study on the Mount Emmons Project. A feasibility study would establish the potential economic viability of the molybdenum property based on a reassessment of historical and additional drilling and sampling data, the design and costs to build and operate a mine and mill, the cost of capital, and other factors. A feasibility study conducted by professional consulting and engineering firms will determine if the deposits contain proved reserves (i.e., amounts of minerals in sufficient grades that can be extracted profitably under current commodity pricing assumptions and estimated development and operating costs).

Geothermal renewable reserve reports estimate the energy potential of geothermal properties in terms of capacity to generate electricity with plants to be built on the properties in the future. Currently we have no reserve reports for our geothermal properties.

The timing and cost to obtain reports for the Mt. Emmons molybdenum property or the geothermal properties cannot be predicted. However, when such reports are obtained, they may not support our internal valuations of the properties, and additionally may not be sufficient to maintain business relationships with current industry partners, or attract new partners or investment capital.

The development of oil and gas properties involves substantial risks that may result in a total loss of investment.

The business of exploring for and developing natural gas and oil properties involves a high degree of business and financial risks, and thus a significant risk of loss of initial investment even a combination of experience, knowledge and careful evaluation may not be able to overcome. The cost of drilling, completing and operating wells is often uncertain. Factors which can delay or prevent drilling or production, or otherwise impact expected results include but are not limited to:

- unexpected drilling conditions;
- permitting with State and Federal agencies;
- easements from land owners;
- adverse weather;
- high pressure or irregularities in geologic formations;
- equipment failures;
- title problems;
- fires, explosions, blowouts, cratering, pollution and other environmental risks or accidents;
- changes in government regulations;
- reductions in commodity prices;
- pipeline ruptures; and
- unavailability or high cost of equipment and field services and labor.

A productive well may become uneconomic in the event that unusual quantities of water or other non-commercial substances are encountered in the well bore, which impair or prevent production. We may participate in wells that are unproductive or, though productive, won't produce in economic quantities.

In addition, initial 24-hour or other limited-duration production rates announced regarding our oil and gas properties are not indicative of future production rates. Such stated rates on our wells should not be used as an indication of future production rates.

We do not currently operate most of our drilling locations, and, therefore, we will not be able to control the timing of exploration or development efforts, associated costs, or the rate of production of these non-operated assets.

Other than the Montana acreage in Daniels County, and the acreage in southeastern Colorado (for which we are the operator), we do not operate or expect to be the operator for any of the prospects we hold with industry partners.

Allowing others to operate limits our ability to exercise influence over the operations of the drilling programs. In the usual case in the oil and gas industry, new work is proposed by the operator and often is approved by most of the non-operating parties. If the work is approved by the holders of a majority of the working interest, but we disagreed with the proposal and did not participate, we would forfeit our share of revenues from the well until the participants receive 200% to 300% of their investment and in some cases, we would lose all interest in the well. This kind of situation would be avoided only if a majority of the working interest owners agreed with us and the proposal did not proceed.

Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or the relevant underlying assumptions will materially affect the quantity and present value of our reserves.

Oil and gas reserve reports are prepared by independent consultants to estimate the quantities of hydrocarbons that can be economically recovered from proved producing and proved undeveloped properties, utilizing current commodity prices and taking into account capital and other expenditures. These reports also estimate the future net present value of the reserves, and are used for internal planning purposes and for testing the carrying value of the properties on our balance sheet.

The reserve data included in this Annual Report represent estimates only. Estimating quantities of proved oil and natural gas reserves is a complex process. It requires interpretations of available technical data and various estimates, including estimates based upon assumptions relating to economic factors, such as future commodity prices, production costs, severance and excise taxes, availability of capital, estimates of required capital expenditures and workover and remedial costs, and the assumed effect of governmental regulation. The assumptions underlying our estimates of our proved reserves could prove to be inaccurate, and any significant inaccuracy could materially affect, among other things, future estimates of the reserves, the economically recoverable quantities of oil and natural gas attributable to the properties, the classifications of reserves based on risk of recovery, and estimates of our future net cash flows.

At December 31, 2010, 70% of our estimated proved reserves were producing, 19% were proved developed non-producing and 11% were proved undeveloped. Estimation of proved undeveloped reserves and proved developed non-producing reserves is almost always based on analogy to existing wells, in contrast to the performance data used to estimate producing reserves. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations.

Revenues from estimated proved developed non-producing reserves will not be realized until sometime in the future, if at all.

You should not assume that the present values referred to in this report represent the current market value of our estimated oil and natural gas reserves. The timing and success of the production and the expenses related to the development of oil and natural gas properties, each of which is subject to numerous risks and uncertainties, will affect the timing and amount of actual future net cash flows from our proved reserves and their present value. In addition, our PV10 estimates are based on costs as of the date of the estimates, and average prices in 2010. Actual future prices and costs may be materially higher or lower than the prices and costs used in the estimate.

Further, the effect of derivative instruments is not reflected in these assumed prices; we have three such instruments in place at December 31, 2010 but did not have any such instruments in place at December 31, 2009. Also, the use of a 10% discount factor to calculate PV10 may not necessarily represent the most appropriate discount factor given actual interest rates and risks to which our business or the oil and natural gas industry in general are subject.

The use of hedging arrangements in oil and gas production could result in financial losses or reduce income.

We use derivative instruments, typically fixed-rate swaps and costless collars to manage price risk underlying our oil and gas production. The fair value of our derivative instrument will be marked to market at the end of each quarter and the resulting unrealized gains or losses due to changes in the fair value of our derivative instrument will be recognized in current earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative instruments.

Our actual future production may be significantly higher or lower than we estimate at the time we enter into derivative contracts for such period. If the actual amount of production is higher than we estimated, we will have greater commodity price exposure than we intended. If the actual amount of production is lower than the notional amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial diminution of our liquidity. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows.

Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counter-party to the derivative instrument defaults on its contract obligations;
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received; or
- the steps we take to monitor our derivative financial instruments do not detect and prevent transactions that are inconsistent with the Company's risk management strategies.

In addition, depending on the type of derivative arrangements we enter, the agreements could limit the benefit we would receive from increases in oil prices. We cannot assure you that the hedging transactions we have entered into, or will enter into, will adequately protect us from fluctuations in oil prices.

We may incur losses as a result of title deficiencies in oil and gas leases.

Typically, operators obtain a preliminary title opinion prior to drilling. To date, our operators have provided preliminary title opinions prior to drilling. In addition, we rely on the operators to provide us with ownership of the interest we pay for. However, from time to time, our operators may not retain attorneys to examine title, even on a preliminary basis, before starting drilling operations. If curative title work is recommended to provide marketability of title (and assurance of payment from production), but is not successfully completed, a loss may be incurred from drilling even a productive well because the operator (and therefore USE) would not own the interest.

Insurance may be insufficient to cover future liabilities.

Our business is focused in three areas, each of which presents potential liability exposure: Oil and gas exploration and development; permitting and limited exploration of the Mt. Emmons molybdenum property; and a residential multi-family housing complex in Gillette, Wyoming. We also have potential exposure in connection with the Company's corporate aircraft and general liability and property damage associated with the ownership of other corporate assets. We rely primarily on the operators of our oil and gas and mineral properties to obtain and maintain liability insurance for our working interest in the properties. We have purchased additional liability insurance for our own account. We maintain insurance policies for the liability of and damage to our multifamily housing complex, corporate aircraft and general corporate assets.

We also have separate policies for liability and environmental exposures for the water treatment plant at the Mt. Emmons project. These policies provide coverage for bodily injury and property damage as well as costs to remediate events adversely impacting the environment. See "Insurance" below.

We would be liable for claims in excess of coverage. If uncovered liabilities are substantial, payment thereof could adversely impact the Company's cash on hand, resulting in possible curtailment of operations. As of the date of this Report, we know of no claims related to any of our properties.

Oil and gas, mineral and geothermal operations are subject to environmental regulations that can materially adversely affect the timing and cost of operations.

Oil and gas exploration and production are subject to certain federal, state and local laws and regulations relating to environmental quality and pollution control. These laws and regulations increase costs and may prevent or delay the commencement or continuance of operations. Specifically, the industry generally is subject to regulations regarding the acquisition of permits before drilling, restrictions on drilling activities in restricted areas, emissions into the environment, water discharges, and storage and disposition of hazardous wastes. In addition, state laws require wells and facility sites to be abandoned and reclaimed to the satisfaction of state authorities. Such laws and regulations have been frequently changed in the past, and we are unable to predict the ultimate cost of compliance as a result of future changes. The adoption or enforcement of stricter regulations, if enacted, could have a significant impact on our operating costs.

Our business activities in geothermal and mining are regulated by government agencies. Permits are required to explore for minerals, operate mines and build and operate processing plants. The regulations under which permits are issued change from time to time to reflect changes in public policy or scientific understanding of issues. If the economics of a project cannot withstand the cost of complying with changed regulations, we might decide not to move forward with the project.

We must comply with numerous environmental regulations on a continuous basis, to comply with United States environmental laws, including the National Environmental Policy Act ("NEPA"), Clean Air Act, the Clean Water Act, and the Resource Conservation and Recovery Act ("RCRA"). Other laws impose reclamation obligations on abandoned mining properties, in addition to or in conjunction with federal statutes. Environmental regulatory programs create potential liability for operators, and may result in requirements to perform environmental investigations or corrective actions under federal and state laws and federal and state Superfund requirements.

Seasonal weather conditions adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and natural gas operations in the Williston Basin and the Gulf Coast are adversely affected by seasonal weather conditions. In the Williston Basin, drilling and other oil and natural gas activities cannot be conducted as effectively during the winter months which could materially increase our operating and capital costs. Gulf Coast operations are subject to the risk of hurricanes.

Our geothermal assets may not be developed.

To complete our geothermal project business plan through acquisition of land positions in numerous prospects and establishing the power potential through drilling will require substantial capital. SST will require additional capital to develop its geothermal prospects. If sufficient funding cannot be obtained through cash calls to the partners in SST, sale of properties and or debt or equity financing, the properties may never be developed with could impact the value of our investment. We have advised SST that we do not intend to fund any future cash calls. At December 31, 2010 we had a 22.8% ownership in SST.

Risks associated with development of the Mount Emmons Project.

The Mount Emmons molybdenum property is located on fee property within the boundary of U.S. Forest Service ("USFS") land. Although mining of the mineral resource will occur on the fee property, associated ancillary activities will occur on USFS land. USE and Thompson Creek Metals submitted a baseline Plan of Operations to the USFS in 2010. The 2010 Plan of Operations is for baseline data collection to prepare the full mine Plan of Operation. Under the procedures mandated by the National Environmental Protection Act ("NEPA"), the USFS will prepare an environmental analysis in the form of an Environmental Assessment to evaluate the predicted environmental and socio-economic impacts of the proposed baseline data collection activity. The NEPA process provides for public review and comment of the proposed plan.

The USFS is the lead regulatory agency in the NEPA process, and coordinates with the various Federal and State agencies in the review and approval of the Mine Plan of Operations. Various Colorado state agencies will have primary jurisdiction over certain areas. For example, enforcement of the Clean Water Act in Colorado is delegated to the Colorado Department of Public Health and Environment and a water discharge permit under the National Pollution Discharge Elimination System ("NPDES") is required before the USFS can approve the Plan of Operations. We currently have a NPDES Permit from the State of Colorado for the operation of the water treatment plant.

In addition, the Colorado Division of Reclamation, Mining and Safety issues mining and reclamation permits for mining activities, pursuant to the Colorado Mined Land Reclamation Act, and otherwise exercises supervisory authority over mining in the state. As part of obtaining a permit to mine, USE and Thompson Creek Metals will be required to submit a detailed reclamation plan for the eventual mine closure, which must be reviewed and approved by the agency. In addition, USE and Thompson Creek

Metals will be required to provide financial assurance that the reclamation plan will be achieved (by bonding and/or insurance) before the mining permit will be issued.

Obtaining and maintaining the various permits for the mining operations at the Mount Emmons Project will be complex, time-consuming, and expensive. Changes in a mine's design, production rates, quality of material mined, and many other matters, often require submission of the proposed changes for agency approval prior to implementation. In addition, changes in operating conditions beyond our and Thompson Creek Metals' control, or changes in agency policy and Federal and State laws, could further affect the successful permitting of the mine operations. The timing and cost, and ultimate success of the mining operation cannot be predicted.

Reliance on Thompson Creek Metals. Thompson Creek Metals is the operator of the Mount Emmons Project and has an option to acquire up to a 75% interest by performing and paying for the work to get the project permitted and operational and making option payments. Thompson Creek could exit our agreement at any time without penalty. Should we be unable to find a replacement partner in due course, U.S. Energy Corp. would have to fund the considerable permitting and development costs thereafter to advance development of the project. We may be unable to obtain such funding on acceptable terms, or at all.

We depend on key personnel.

Our employees have experience in dealing with the exploration and financing of mineral properties, but we have a limited technical staff and executive group. From time to time we rely on third party consultants for professional geophysical and geological advice in oil and gas matters, and on Thompson Creek Metals for mining expertise. The loss of key employees could adversely impact our business, as finding replacements could be difficult as a result of competition for experienced personnel in the minerals industry. We hired an experienced geologist in 2010, and are searching for additional employees to provide full time talent as we expand staffing to operate some properties.

Risks Related to Our Stock

We have authorization to issue shares of preferred stock with greater rights than our common stock.

Although we have no current plans, arrangements, understandings or agreements to do so, our articles of incorporation authorize the board of directors to issue one or more series of preferred stock and set the terms of the stock without seeking approval from holders of the common stock. Preferred stock that is issued may have preferential rights over the common stock, in terms of dividends, liquidation rights and voting rights.

Future equity transactions and exercises of outstanding options or warrants could result in dilution.

From time to time, we have sold restricted stock and warrants and convertible debt to investors in private placements conducted by broker-dealers, or in negotiated transactions. Because the stock was issued as restricted, the stock was sold at a discount to market prices, and/or the debt-to-stock conversion price was at or lower than market. These transactions caused dilution to existing shareholders. Also, from time to time, options and warrants are issued to employees, directors and third parties as incentives, with exercise prices equal to market prices at dates of issuance. Exercise of in-the-money options and warrants could result in dilution to existing shareholders.

We do not intend to declare dividends on our common stock.

We paid a one-time special cash dividend of $0.10 per share on our common stock in July 2007. However, we do not intend to declare dividends in the foreseeable future.

We have in place take-over defense mechanisms that could discourage some advantageous transactions.

We have adopted a shareholder rights plan, also known as a poison pill. The plan is designed to discourage a takeover of the Company at an unfair price. However, it is possible that the board of directors and a potential takeover acquirer would not agree on a higher price, in which case the takeover might be abandoned, even though the takeover price might be at a significant premium to market prices. Therefore, as a result of the mere existence of the plan, shareholders may not receive the premium price.

Our stock price likely will continue to be volatile due to several factors.

Our stock is traded on the Nasdaq Capital Market. In the two years ended December 31, 2010, the stock has traded as high as $7.06 per share and as low as $1.54 per share. The principal factors which have contributed, or in the future could contribute, to this volatility include:

- price swings in the oil and gas commodities markets;
- price and volume fluctuations in the stock market generally;
- relatively small amounts of USE stock trading on any given day;
- fluctuations in USE’s financial operating results;
- industry trends;
- legislative and regulatory changes; and
- global economic uncertainty

Item 1 B - Unresolved Staff Comments.

None.

Item 2 – Properties

Oil and Natural Gas

The following table sets forth our net proved reserves as of the dates indicated. Our reserve estimates as of December 31, 2009 and 2010 are based on reserve reports prepared by Ryder Scott Company, L.P. (“Ryder Scott”), and Cawley, Gillespie & Associates, Inc. (“CGA”). Our reserve estimates as of December 31, 2008 are based on a reserve report prepared by Ryder Scott Company, L.P. Ryder Scott and CGA are nationally recognized independent petroleum engineering firms. Ryder Scott is a Texas Registered Engineering Firm (F-1580). Our primary contact at Ryder Scott is Mr. James F. Latham, Senior Vice President. Mr. Latham is a State of Texas Licensed Professional Engineer (License #49586). CGA is a Texas Registered Engineering Firm (F-693). Our primary contact at CGA is Mr. W. Todd Brooker, Vice President. Mr. Brooker is a State of Texas Licensed Professional Engineer (License # 83462). Ryder Scott prepared the estimates related to our Gulf Coast Basin, including Louisiana and Texas properties and CGA prepared the estimates for our North Dakota properties. The reserve estimates were based upon the review by the relevant engineering firm(s) of production histories and other geological, economic, ownership and engineering data, as provided by us and by the operators. Copies of these reports are filed as exhibits to this Annual Report.

We do not have in-house geophysical or reserve engineering expertise. We therefore primarily rely on the operators of our producing wells who provide production data to our contract reserve engineers.

Summary of Oil and Gas Reserves as of Fiscal Year End (1)

	December 31, 2010	2009	2008
Net proved reserves			
Oil (Bbls)			
Developed	1,362,733	811,789	29,798
Undeveloped	183,713	--	--
Total	1,546,446	811,789	29,798
Natural gas (Mcf)			
Developed	1,996,490	1,502,296	1,000,000
Undeveloped	139,286	--	--
Total	2,135,776	1,502,296	1,000,000
Plant Products (Bbls)			
Developed	52,532	24,031	--
Undeveloped	--	--	--
Total	52,532	24,031	--
Total proved reserves (BOE)	1,954,941	1,086,203	196,465

(1) 2009 and 2010 reserves are based on average prices per barrel of oil and per MMbtu of natural gas at the first day of each month in the 12-month period prior to the end of the reporting period. 2008 reserves are based on the price per barrel of oil and per MMbtu of natural gas on the last day of 2008.

As of December 31, 2010, our proved reserves totaled 1,954,941 BOE (89% developed and 11% undeveloped), comprised of 1,546,446 Bbls of oil (79% of the total), 2,135,776 Mcf of natural gas and 52,532 Bbls of natural gas liquid. See the "Glossary of Oil and Gas Terms" for an explanation of these and other terms. You should not place undue reliance on estimates of proved reserves. See "Risk Factors - Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or the relevant underlying assumptions will materially affect the quantity and present value of our reserves".

Proved Undeveloped Reserves

Proved undeveloped reserves of 183,713 barrels of oil and 139,286 Mcf of natural gas were added in 2010 in connection with drilling completed by our partners. We had no proved undeveloped reserves at December 31, 2009 and accordingly, there were no conversions of proved undeveloped reserves to proved developed producing wells in 2010.

-31-

Oil and Gas Production, Production Prices, and Production Costs

The following table sets forth certain information regarding our net production volumes, average sales prices realized and certain expenses associated with sales of oil and natural gas for the periods indicated. We urge you to read this information in conjunction with the information contained in our financial statements and related notes included in this Annual Report. The information set forth below is not necessarily indicative of future results.

	December 31, 2010	2009	2008
Production Volume			
Oil (Bbls)	303,433	80,461	2,330
Natural gas (Mcf)	757,905	467,691	73,635
Natural gas liquids (Bbls)	19,104	5,987	--
BOE	448,855	164,397	14,603
Daily Average Production Volume			
Oil (Bbls/d)	831	220	6
Natural gas (Mcf/d)	2,076	1,281	202
Natural gas Liquids (Bbls/d)	52	16	--
BOE/d	1,230	450	40
Oil Price per Bbl Produced			
Realized Price	$ 72.11	$ 66.22	$ 35.50
Natural Gas Price per Mcf Produced			
Realized Price	$ 4.96	$ 4.30	$ 6.88
Natural Gas Liquids Price per Bbl Produced			
Realized Price	$ 47.53	$ 40.25	$ --
Average Sale Price per BOE (1)	$ 59.15	$ 46.11	$ 40.35
Expense per BOE			
Production costs (2)	$ 6.81	$ 2.40	$ 4.26
Depletion, depreciation and amortization	$ 23.64	$ 21.72	$ 26.16

(1) Amounts shown are based on oil and natural gas sales, divided by sales volumes. Natural gas produced but flared is not included.

(2) Production costs are comprised of oil and natural gas production expenses (excluding ad valorem and severance taxes), and are computed using production costs as determined under ASC 932-235-55.

Drilling and Other Exploratory and Development Activities

The following table sets forth information with respect to development and exploration wells we completed from January 1, 2008 through December 31, 2010. The number of gross wells is the total number of wells we participated in, regardless of our ownership interest in the wells.

	Development Wells Drilled		
	2010	2009	2008
Producing			
Gross	--	--	--
Net	--	--	--
Dry			
Gross	--	--	--
Net	--	--	--

	Exploration Wells Drilled		
	2010	2009	2008
Producing			
Gross	8.0000	8.0000	1.0000
Net	2.9409	3.3286	0.1500
Dry			
Gross	5.0000	2.0000	1.0000
Net	0.3902	0.5833	0.2000

The information above should not be considered indicative of future drilling performance, nor should it be assumed that there is any correlation between the number of productive wells drilled and the amount of oil and natural gas that may ultimately be recovered. See "Management's Discussion and Analysis of Financial Condition and Results of Operation – General Overview."

Oil and Natural Gas Properties, Wells, Operations and Acreage

The following table details our working interests in producing wells as of December 31, 2010. A well with multiple completions in the same bore hole is considered one well. Wells are classified as oil or natural gas wells according to the predominant production stream, except that a well with multiple completions is considered an oil well if one or more is an oil completion.

	Gross Producing Wells	Net Producing Wells	Average Working Interest (1)
Oil	14.00	5.63	40.21214 %
Natural Gas	3.00	0.75	24.99333 %
Total (1)	17.00	6.38	37.52647 %

(1) The average working interest for the thirteen Williston Basin wells producing at December 31, 2010 is 41.38%; the remaining four wells (Southeast Texas and Louisiana), have 7.65%, 14%, 25% and 53.3% working interests, respectively.

The following map reflects where our oil and gas wells are generally located in the Williston Basin of North Dakota:

Acreage

The following table summarizes our estimated developed and undeveloped leasehold acreage as of December 31, 2010.

	Developed		Undeveloped		Total	
Area	Gross	Net	Gross	Net	Gross	Net
Williston Basin	14,080	5,955	51,090	19,144	65,170	25,099
Texas and Louisiana	4,414	978	12,734	845	17,148	1,823
California	--		7,178	2,448	7,178	2,448
Total	18,494	6,933	71,002	22,437	89,496	29,370

Present Activities

As of March 1, 2011, we were drilling 1 gross (0.30 net) wells in the Williston Basin, and 5 gross (1.51 net) wells in the Williston Basin were drilled and waiting on completion.

Molybdenum – Mount Emmons Project

We re-acquired the Mount Emmons (formerly known as the Lucky Jack molybdenum property) located near Crested Butte, Colorado on February 28, 2006. The property was returned to us by Phelps Dodge Corporation ("PD") in accordance with a 1987 Amended Royalty Deed and Agreement between us and Amax Inc. ("Amax"). The Mount Emmons Project includes a total of 25 patented and approximately 1,219 unpatented mining and mill site claims, which together approximate 9,311 acres, or over 13 square miles of claims.

We own both surface and mineral rights at the Mount Emmons Project in fee pursuant to mineral patents issued by the United States of America. All fee property requires the payment of property taxes to Gunnison County. Unpatented mining and mill site claims require the payment of an annual maintenance fee of $140 per claim to the Bureau of Land Management; the total amount paid for claim maintenance fees in 2010 was $171,000, which was paid by TCM.

The breakdown of the property is as follows:

	Acres	Number of Claims
Patented / Fee	365	25
Unpatented Claims	6,171	664
Mill Site Claims	2,775	555
Fee Property (1)	160	n/a
Total	9,471	1,244

(1) This property (fee ownership) is in the vicinity of the mining claims but presently is not considered by TCM and U.S. Energy to be part of the Mount Emmons Project.

The Mount Emmons Project is located in Gunnison County, Colorado. The property is accessed by vehicle traffic on Gunnison County Road 12.

Thompson Creek Metals Company (USA) has an option to acquire up to a 75% interest in the Project. See Part I above.

We had leased various patented and unpatented mining claims on the Mount Emmons molybdenum property to Amax in 1974. In the late 1970s, Amax delineated a large deposit of molybdenum on the properties, reportedly containing approximately 155 million tons of mineralized material averaging 0.44% molybdenum disulfide (MoS_2). In 1981, Amax constructed a water treatment plant at the Mount Emmons molybdenum property to treat water flowing from the old Keystone mine workings and for potential use in milling operations. By 1983, Amax had reportedly spent an estimated $150 million in the acquisition of the property, securing water rights, extensive exploration, ore body delineation, mine planning, metallurgical testing and other activities involving the mineral deposit. Amax was merged into Cyprus Minerals in 1992 to form Cyprus Amax. PD then acquired Mount Emmons in 1999 through its acquisition of Cyprus Amax. Thereafter, PD acquired additional conditional water rights and patents to certain mineral claims.

The exploration work conducted in the late 1970's by Amax, Inc. as discussed in Cyprus Amax's Patent Claim Application to the Bureau of Land Management dated December 23, 1992, defined the initial mineralized material at the Mount Emmons Project as follows: "Molybdenite is present in randomly distributed veinlets (i.e. stockwork veining) and in some larger veins that are up to two feet wide. This mineralized zone is found in metamorphosed sedimentary rocks and in Tertiary igneous complex which acted as the source of the mineralization."

There also are a number of existing mine adits located on the property. Historic work completed by Amax, Inc. in the 1970s and early 1980s included: 2,400 feet of new drift with 18 underground diamond drill stations to facilitate underground drilling (consisting of 168 diamond drill holes for a total of 157,037 feet of core drilling). The majority of the drilling was concentrated within 3,000 feet north and south; 3,000 feet east and west and 2,000 vertical feet defining the area of mineralized material. A bulk sample was collected from this area and sent off site for metallurgical testing. Amax, Inc. also facilitated the completion of an Environmental Impact Statement ("EIS") as required by NEPA for the Plan of Operations submitted to the United States Forest Service ("USFS"). The Amax, Inc. EIS is now outdated.

In its 1992 patent application, Cyprus Amax stated that the size and grade of the Mount Emmons deposit was determined to approximate 220 million tons of mineralized material grading 0.366% molybdenite. In a letter dated April 2, 2004, the BLM estimated that there were about 23 million tons of mineralized material containing 0.689% molybdenite, and that about 267 million pounds of molybdenum trioxide was recoverable. This letter covered only the high-grade mineralization which is only a portion of the total mineral deposit delineated to date. The BLM relied on a mineral report prepared by Western Mine Engineering ("WME") for the U.S. Forest Service, which directed and administered the WME contract. WME's analysis was based upon a price of $4.61 per pound for molybdic oxide and was used by the BLM in determining that nine claims satisfied the patenting requirement that the mining claims contain a valuable mineral that could be mined profitably. WME consulted a variety of sources in preparation of its report, including a study prepared in 1990 by American Mine Services, Inc. and a pre-feasibility report later prepared by Behre Dolbear & Company, Inc. in 1998.

Even with the historical data available, the size, configuration and operations of the mine plan that may be proposed by TCM have not been finalized. These factors, as well as the prevailing prices for molybdic oxide when the mine is active, will determine the economic viability of the project. We note that the statements made by the predecessor owners of the Mount Emmons Project regarding "recoverable" minerals and "mineable "reserves" were based on costs, permitting requirements, and commodity prices then prevailing. The $4.61 price used by WME should not be considered to be a current breakeven price for Mount Emmons. It is anticipated that a full feasibility study will be prepared in the future, using current and expected capital costs, and operating expenses, to estimate the viability of the project. It will be possible to classify some, or none, of the mineralized resources as "reserves" or "recoverable" only after a full feasibility study, based on a specific mine plan, has been completed.

In December 2008, an additional 160 acres of fee land in the vicinity of the claims was purchased for $4 million ($2 million in January 2009, $400,000 annually for five years). We share with TCM the purchase cost of this land on a 50-50 basis.

Geology

The sedimentary sequence in the Mount Emmons area spans from late Cretaceous to early Tertiary time. The oldest formation is the Mancos, a 4,000 foot sequence of shales with some interbedding limestone and siltstones. The Mancos Formation is not exposed on Mount Emmons, but may be seen in valley bottoms a few miles to the north, south, and east. All of the Mancos Formation encountered in the vicinity of the Mount Emmons mineralization has been strongly metamorphosed and attempts to correlate internal divisions of the unit have not been made. The overlying Mesaverde Formation, also of the late Cretaceous age, consists of a massive repetitive sequence of alternating sandstones, siltstones, shales and minor coals. Coal seams were not observed in any of the diamond drill holes, or in any of the underground drifts. On Mount Emmons the Mesaverde Formation varies from 1,100 to 1,700 feet thick. The variability in thickness of the Mesaverde Formation is mainly due to post-depositional erosion. The Ohio Creek Formation, dominantly a coarse sandstone with local chert pebble conglomerate and well-defined shale to siltstone beds, overlies the Mesaverde Formation. The Ohio Creek Formation is of early Tertiary (Paleocene) age and remains fairly consistent at 400 feet thick on Mount Emmons. Capping Mount Emmons is the Wasatch Formation, also of early Tertiary (Paleocene to Eocene) age.

-37-

On a more regional scale, within the Ruby Range the Wasatch Formation may reach 1,700 feet in thickness. However, on Mount Emmons specifically, all but the basal 600 to 700 feet has been eroded. The Wasatch Formation is composed of alternating sequences of immature shales, siltstones, arkosic sandstones, and volcanic pebble conglomerates. The Mount Emmons stock has intruded the Mancos and Mesaverde sediments, strongly metamorphosing both formations to hornfels up to 1500 feet outward from the igneous body.

Sedimentary rocks on Mount Emmons generally dip 15 – 20 degrees to the southeast, south, and southwest as is consistent with the locations of the Oh-Be-Joyful anticline and Coal Creek syncline.

During crystallization of the Red Lady Complex, hydrothermal fluids collected near the top of the magma column. These fluids were released after a period of intense fracturing in the solid upper portions of the Red Lady Complex and the surrounding country rock. This release of fluids was responsible for the formation of the major part of the Mount Emmons molybdenum mineralized zone and the associated alteration zones. Hydrothermal alteration associated with the Mount Emmons stock occurs in several distinct overlapping zones. Altered rocks include sedimentary rocks of the Mancos, Mesaverde, Ohio Creek and Wasatch Formations, the rhyodacite porphyry sills, and rocks of the Mount Emmons stock.

Water Treatment Plant; Site Facilities

PD's 2006 re-conveyance of the property to U.S. Energy also included the transfer of ownership and operational responsibility of the mine water treatment plant located on the property. The water treatment permit issued under the Colorado Discharge Permit System was assigned to us by the Colorado Department of Health and Environment. We are responsible for all operating and maintenance costs until such time as Thompson Creek Metals elects to acquire a 15% interest in the property. Thereafter, costs will be shared according to our and Thompson Creek's participation interests. We also are evaluating using the plant in milling operations.

The water treatment plant was constructed by Amax, Inc. in 1981 (at a cost of approximately $15 million) to treat mine discharge water from the historic lead and zinc Keystone Mine. A certified water treatment plant operations contractor with four licensed and/or trained employees operate the water treatment plant on a continuous basis, treating water discharged from the historic lead and zinc Keystone Mine. The plant utilizes a standard lime pH adjustment to precipitate heavy metals from the water. Mine water is then filtered and discharged in compliance with the approved NPDES Permit for the plant, and solids are dewatered and mixed with cement for proper disposal in accordance with state and federal law.

Additional equipment used in the operation of the water treatment plant includes a large front-end loaders, forklifts, specialized snow removal equipment and pickup trucks. The Mount Emmons Project currently has a 24-hour, seven days a week security contract service to protect the property.

Several capital upgrades to onsite facilities have been made since 2006. Current facilities include a core and office building, five ancillary pump houses and underground pipelines and utilities, which move water from five water storage ponds to the water treatment plant. Surface access is maintained to the four underground adits and the ancillary pump houses.

Historical Capital Expenditures by Prior Owners, and Related Information

Amax, Inc. reportedly spent approximately $150 million in exploration and related activities on the Mount Emmons Project, which included construction of the water treatment plant. During 2007, Kobex Resources, the predecessor of

TCM, spent approximately $10.5 million on the property. From August 2008 to December 31, 2010, TCM has spent approximately $12.2 million on the property. Our annual operating cost for the water treatment plant is approximately $1.8 million. The total costs associated with future drilling and the development of the Project has not yet been determined by TCM.

We are using grid electric power to operate the water treatment plant and other facilities from the local electric utility serving Gunnison County. We have been granted conditional water rights from the State of Colorado for operation and development of the Project. TCM is reviewing and evaluating potential future power and water needs, however no definitive development project plans have been finalized or approved at this time.

Additional drilling will need to be conducted to further delineate the depth, grades and volume of mineralized materials before we can determine if there are reserves present in the project (presently in the advanced exploration stage). The time table for completing drilling, and the permitting and construction of the mine and milling facilities, is dependent upon several factors, including local, State and Federal regulations and availability of capital, which is driven by the market price for molybdenum.

Activities in 2010 and Plans for 2011

TCM, the Project Manager, submitted a baseline Plan of Operations on March 30, 2010, to the US Forest Service and has been responding to questions from the USFS as they review the baseline Plan of Operations (“PoO”). The NEPA process that the USFS will follow for review of the baseline PoO is an EA. We expect that the baseline Plan of Operations will facilitate the base line data collection needed for additional permitting efforts.

At the date of this filing, TCM is reviewing and developing a detailed plan to conduct prospecting activities underground in the existing 2000 drift drill stations. This plan is expected to be completed and approved later in 2011.

Information About Molybdenum Markets

The metallurgical market for molybdenum is characterized by cyclical and volatile prices, little product differentiation and strong competition. In the market, prices are influenced by production costs of domestic and foreign competitors, worldwide economic conditions, world supply/demand balances, inventory levels, the U.S. Dollar exchange rate and other factors. Molybdenum prices also are affected by the demand for end-use products in, for example, the construction, transportation and durable goods markets. A substantial portion the of world’s molybdenum supply is produced as a by-product of copper mining. Today, by-product production is estimated to account for approximately 60% of global molybdenum production.

Annual Metal Week Dealer Oxide mean prices averaged $16.00 in 2010, compared to $11.29 in 2009. The increase in the average annual price for molybdenum is a result of the global economic recovery from the Great Recession which led to dramatic reductions in steel output and pricing, and correspondingly in market demand for molybdenum and it’s pricing.

Real Estate

Remington Village - Gillette, Wyoming.

We have built and own a nine building multifamily apartment complex, with 216 units on 10.15 acres located in Gillette, Wyoming. The apartments are a mix of one, two, and three bedroom units, with a clubhouse and family amenities for the complex. This project is held by our wholly-owned subsidiary Remington Village, LLC.

-39-

Occupancy averaged 89.6% in 2010. For the year, we realized average monthly revenues of approximately $198,000. The occupancy rate at December 31, 2008 was 88%, 80% at December 31, 2009 and 89% at December 31, 2010. The decrease in occupancy rate from 2008 to 2009 was due to the national economic downturn and reduced activities in the oil and gas sector in Wyoming. The apartment complex, along with our corporate aircraft, is pledged as collateral for a $10 million commercial line of credit with a financial institution.

The Company had an appraisal completed as of December 31, 2010 which valued the property at $21.0 million. An impairment of $1.5 million was therefore recorded at December 31, 2010 on the property. Although the property produces positive cash flow from its operations, the return from oil and gas investments is expected to yield a higher return. In 2011 the Company plans on financing and then selling this property to continue growing its oil and gas business.

Fremont County, Wyoming

U.S. Energy owns a 14-acre tract in Riverton, Wyoming, with a two-story 30,400 square foot office building. The first floor is rented to non-affiliates and government agencies; the second floor is occupied by the Company. In addition, own three city lots covering 13.84 acres adjacent to USE's corporate office building. When the real estate market recovers we intend to sell this property without development. The timing of sale is not known. We also own a 10,000 square foot aircraft hangar on land leased from the City of Riverton with 7,000 square feet of associated offices and facilities and two vacant lots covering 13.2 acres in Fremont County, Wyoming.

Sold Uranium Properties – Possible Future Revenues

In 2007, we sold all of our uranium assets for cash and stock of the purchaser. Included in the sold assets were the Shootaring Canyon uranium mill in Utah and unpatented uranium claims in Wyoming, Colorado, Arizona and Utah. Pursuant to the asset purchase agreement, we may also receive from the purchaser:

- $20,000,000 cash when the Shootaring Canyon Mill has been operating at 60% or more of its design capacity of 750 short tons per day for 60 consecutive days.

- $7,500,000 cash on the first delivery (after commercial production has occurred) of mineralized material from any of the claims we sold to a commercial mill (excluding existing ore stockpiles on the properties).

- From and after commercial production occurs at the Shootaring Canyon Mill, a production payment royalty (up to but not more than $12,500,000) equal to five percent of (i) the gross value of uranium and vanadium products produced at and sold from the mill; or (ii) mill fees received by the purchaser from third parties for custom milling or tolling arrangements, as applicable. If production is sold to an affiliate of the purchaser, partner, or joint venturer, gross value shall be determined by reference to mining industry publications or data.

The timing of future receipt of funds from any of these contingencies is not known.

Royalty on Uranium Claims

We hold a 4% net profits interest on unpatented mining claims on Rio Tinto's Jackpot uranium property located on Green Mountain in Wyoming.

Research and Development

No research and development expenditures have been incurred, either on the Company's account or sponsored by a customer of the Company, during the past three fiscal years.

Environmental

Operations are subject to various federal, state and local laws and regulations regarding the discharge of materials into the environment or otherwise relating to the protection of the environment, including the National Environmental Policy Act ("NEPA"), Clean Air Act, the Clean Water Act, the Resource Conservation and Recovery Act ("RCRA"), and the Comprehensive Environmental Response Compensation Liability Act ("CERCLA"). With respect to proposed mining operations at the Mount Emmons property, Colorado's mine permitting statute, the Abandoned Mine Reclamation Act, and industrial development and siting laws and regulations, also may affect the project. We believe we are in compliance in all material respects with existing environmental regulations. For information on the approximate reclamation costs (decommissioning, decontamination and other reclamation efforts for which we are primarily responsible or potentially responsible) related to the Mount Emmons project, see the consolidated financial statements included in Part II of this Annual Report.

Gas and oil operations also are subject to various federal, state and local governmental and environmental regulations, including regulations governing natural gas and oil production, federal and state regulations for environmental quality and pollution control, and state limits on allowable rates of production by well. These regulations may affect the amount of natural gas and oil available for sale, the availability of adequate pipeline and other regulated transportation and processing facilities, and other matters. State and federal regulations generally are intended to prevent waste of natural gas and oil, protect rights to produce natural gas and oil between owners in a common reservoir, control the amount produced by assigning allowable rates of production and control contamination of the environment. Pipelines are subject to the jurisdiction of various federal, state and local agencies. From time to time, various proposals are made by regulatory agencies and legislative bodies. Regulatory changes can adversely impact the permitting and exploration and development of mineral and oil and gas properties including the availability of capital.

Although all of our oil and gas properties are operated by third parties, the activities on the properties are still subject to environmental protection regulations. Operators are required to obtain drilling permits, restrict substances that can be released into the environment, and require remedial work to mitigate pollution from operations (such as pollution from operations), close and cover disposal pits, and plug abandoned wells. Violations by the operator could result in substantial liabilities, and we would have to pay our share. Based on the current regulatory environment in those states where we have oil and natural gas investments, we don't expect to make any material capital expenditures for environmental control facilities.

Failure to comply with these regulations could result in substantial fines, environmental remediation orders and/or potential shut down of a project until compliance is achieved. Failure to timely obtain required permits to start operations at a project could cause delay and/or the failure of the project resulting in a potential write-off of the investments made.

Insurance

The Company has the following insurance coverage:

General

A general liability policy provides $1 million of liability coverage per occurrence, $2 million general aggregate limit and a $10 million commercial excess liability policy. These policies cover bodily injury and property damage, but do not cover all potential liabilities for Company activities. Accordingly, we have additional policies related to other areas of our business.

Oil and Gas Exploration and Development

Pursuant to the Joint Operating Agreements ("JOAs") between the Company and each operator of the properties where we hold working interests, each working interest owner is responsible for paying its share of costs and expenses related to operations. The liability of the parties is several, not joint or collective, and the relationship between the parties is not a partnership. None of the JOAs provide for indemnification between the parties.

The JOAs also require the operator to obtain and maintain liability insurance for the benefit of all the working interest owners (premiums are paid pro rata by the working interest owners). Policies currently in place provide $1 million per event, $2 million general aggregate liability coverage, $1 million auto insurance, excess coverage (overlaying the preceding) of $5 million to $20 million and $5 million to $15 million for "operator's extra expense" (control of well). Premiums are paid by the working interest owners pro rata to ownership.

The Company has also purchased non-operator liability insurance providing $1 million of liability coverage per occurrence, $2 million general aggregate limit and $20 million in excess liability.

Mt. Emmons Project

The Company is responsible for all costs to operate the water treatment plant at the Mt. Emmons project until Thompson Creek Metals Company USA ("TCM") elects to exercise its option to own an interest in the property. We maintain an insurance policy for our benefit in the amounts of $1 million per event, $2 million aggregate general liability, $1 million automobile liability, $10 million environmental impairment liability, and $10 million excess liability (an upper limit on the coverage other than environmental).

U.S. Energy is an additional insured under TCM's policies with respect to operations at Mt. Emmons not related to the water treatment plant, with policy limits of $1 million per event, $2 million general aggregate liability, and excess liability of $10 million.

We believe the above insurance is sufficient in the current permitting-exploration stage of the Mt. Emmons project. Additional insurance will be obtained as the level of activity in exploration and development expands.

Corporate Aircraft

The Company maintains a $20 million per event liability policy on its corporate aircraft. We also maintain physical damage insurance, $200,000 and $4 million, on the aircraft which approximates their replacement value.

Remington Village

We have a policy covering $1 million each event, $2 million general aggregate liability and a $9 million of excess liability policy. The deductibles are $1,000 ($5,000 retained limited) per event. We maintain $20.4 million of coverage for the real property written on a Special Form/Replacement Cost basis.

Employees

As of March, 2011, we had 19 full-time employees.

Mining Claim Holdings

Title

Approximately 25 of the Mount Emmons mining claims are patented claims; however the majority of claims are unpatented.

Unpatented claims are located upon federal and public land pursuant to procedures established by the General Mining Law, which governs mining claims and related activities on Federal public lands. Requirements for the location of a valid mining claim on public land depend on the type of claim being staked, but generally include discovery of valuable minerals, erecting a discovery monument and posting thereon a location notice, marking the boundaries of the claim with monuments, and filing a certificate of location with the county in which the claim is located and with the U.S. Bureau of Land Management ("BLM"). If the statutes and regulations for the location of a mining claim are complied with, the locator obtains a valid possessory right to the contained minerals. To preserve an otherwise valid claim, a claimant must also pay certain rental fees annually to the federal government and make certain additional filings with the county and the BLM. Failure to pay such fees or make the required filing may render the mining claim void or voidable.

Because mining claims are self-initiated and self-maintained, they possess some unique vulnerability not associated with other types of property interests. It is impossible to ascertain the validity of unpatented mining claims solely from public records and it can be difficult or impossible to confirm that all of the requisite steps have been followed for location and maintenance of a claim. If the validity of an unpatented mining claim is challenged by the government, the claimant has the burden of proving the economic feasibility of mining minerals located thereon. However, we believe that all of our Mount Emmons mining claims are valid and in good standing.

Proposed Federal Legislation

The U.S. Congress from time to time has considered proposed revisions to the General Mining Law, including as recently as 2009. If these proposed revisions are enacted, payment of royalties on production of minerals from federal lands could be required as well as additional procedural measures, new requirements for reclamation of mined land, and other environmental control measures. The effect of any revision of the General Mining Law on operations cannot be determined until enactment, however, it is

possible that revisions would materially increase the carrying and operating costs of mineral properties located on federal unpatented mining claims.

Item 3 – Legal Proceedings

Material legal proceedings pending at December 31, 2010, and developments in those proceedings from that date to the date this Annual Report was filed, are summarized below.

Water Rights Litigation –Mount Emmons Molybdenum Property

Concerning the Application of U.S. Energy, Case No. 2008CW81. On July 25, 2008, the Company filed an Application for Finding of Reasonable Diligence with the Water Court ("Water Diligence Application") concerning the conditional water rights associated with Mount Emmons (Case No. 2008CW81). The conditional water decree ("Decree") requires the Company to file its proposed plan of operations and associated permits with the Forest Service and BLM within six years of entry of the 2002 Decree, or within six years of the final determination in the Applicant's pending patent application, whichever occurs later. The BLM issued the mineral patents on April 2, 2004. Although, the issuance of the patents was appealed, on April 30, 2007, the United States Supreme Court made a final determination upholding BLM's issuance of the mineral patents.

The Company believes that the deadline for filing the plan of operations specified by the Decree is April 30, 2013 (six years from the final determination of issuance of the mineral patents by the United States Supreme Court). The Forest Service has indicated that the deadline should be April 2, 2010 (six years from the issuance of the mineral patents by BLM). The United States, on behalf of the Forest Service and BLM, filed a Statement of Opposition on this specific issue only. Statements of Opposition were also filed by six other parties including the City of Gunnison, the Colorado Water Conservation Board, High Country Citizens' Alliance, Crested Butte Land Trust and others for various reasons, including requesting the Company be put on strict proof as to demonstrating evidence of reasonable diligence in developing the conditional water rights.

On March 26, 2010, BLM and the Forest Service signed a Stipulation with the Company, which resolved their opposition to the Company's Water Diligence Application. Pursuant to the Stipulation, the Company agreed to prepare, in consultation with the BLM and Forest Service, and file no later than April 2, 2010, an initial Plan of Operations in accordance with 36 C.F.R. Sec. 228.4(d). BLM, the Forest Service and the Company also agreed the filing of this Plan of Operations would satisfy the Decree. The Company filed the Plan of Operations on March 31, 2010.

On August 11, 2010, High Country Citizen's Alliance, Crested Butte Land Trust and Star Mountain Ranch Association, Inc ("Opposers") filed a Motion for Summary Judgment alleging that the Plan of Operations did not comply with the Forest Service regulations and did not satisfy certain Reality Check Limitations contained in the Water Rights Decree. On September 24, 2010, U.S. Energy filed a Response to the Motion for Summary Judgment responding that the Plan of Operations complied with the Forest Service and BLM's regulations and satisfied the Reality Check provision contained in the Water Rights Decree and alternately that the Company had until April 30, 2013 to comply with the Reality Check provision, which is six years after the Supreme Court denied certiorari in the judicial proceeding. The U.S. Department of Justice also filed a response on behalf of the Forest Service and BLM that the Court cannot second guess the Forest Service's determination that the Company's Plan of Operations satisfied the Forest Service and BLM's regulations.

On November 24, 2010 the District Court Judge denied the Opposers's Motion for Summary Judgment and held that Company had until April 30, 2013 to comply with the Reality Check provision of the Decree, which is six years after the Supreme Court denied certiorari in the judicial proceeding. The question of the adequacy of the Water Diligence Application is pending.

Appeal of Approval of Notice of Intent to Conduct Prospecting for the Mount Emmons Property

On January 3, 2008, the Division of Reclamation, Mining and Safety of the Colorado Department of Natural Resources ("DRMS") approved the Company's Notice of Intent to Conduct Prospecting Notice for the Mount Emmons molybdenum property ("NOI"). The approved NOI provides for continued exploration of the molybdenum deposit to update, improve and verify, in accordance with current industry standards and legal requirements, mineralization data that was collected by Amax in the late 1970's.

On March 8, 2008, High Country Citizens' Alliance ('HCCA") filed a request for hearing before the Colorado Mine Land Reclamation Board ("MLRB") appealing the NOI, claiming it was not prospecting, but rather development and mining. On May 14, 2008, the MLRB denied HCCA's Request for Hearing and also denied their Request for a Declaratory Order. Citing Colorado law, the MLRB determined that HCCA did not have standing or the right to appeal DRMS's approval of the NOI under Colorado law.

On August 28, 2008, HCCA appealed the MLRB's decision in Denver District Court. Plaintiff: High Country Citizen's Alliance v. Defendants: Colorado Mined Land Reclamation Board, Colorado Division of Reclamation Mining and Safety and U.S. Energy Corp., Case No.: 08CV6156 (District Court, 2d Jud. Dist., City and County of Denver). The MLRB has filed an answer with the Court. The DRMS and the Company (in conjunction with TCM) have both filed the responsive pleadings in addition to motions to dismiss the HCCA complaint.

On February 24, 2011, the Denver, Colorado District Court issued an Order dismissing all of HCCA's claims concerning the appeal of U.S. Energy's NOI holding that: (i) HCCA does not have standing to request judicial review on the merits of the DRMS's approval of U.S. Energy's NOI and (ii) HCCA does not have standing to request a Declaratory Order. This decision upholds MLRB's May 14, 2008 decision denying HCCA's Request for Hearing and their Request for a Declaratory Order because HCCA did not have standing or the right to appeal DRMS's approval of the NOI under Colorado law.

On January 20, 2010 the Company submitted Modification MD-03 ("MD-03") to the NOI. On November 15, 2010 DRMS issued its determination that MD-03 was complete, the activities proposed were prospecting and that MD-03 was approved. On November 19, 2010 HCCA filed an appeal with the MLRB claiming that: (i) the proposed activities were not prospecting, but rather development and mining, (ii) the current financial warranty amount was insufficient to cover the proposed activities and (iii) the permit should be conditioned upon its compliance with other federal and local governmental agency requirements.

On January 12, 2011, the MLRB on a vote 4-1 vote upheld DRMS's approval of MD-03 and their determination that: (i) the activities proposed by the NOI and MD-03 are prospecting, not development or mining, (ii) the current financial warranty amount is sufficient to cover the proposed activities and (iii) DRMS's decision not to make its approval of MD-03 contingent on permits or licenses that may be required by federal , other state, or local agencies was proper and affirmed that decision. On March 2, 2011, HCCA appealed MLRB's decision on MD-03 to the Denver, Colorado District Court.

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

On June 25, 2010, the annual meeting of shareholders was held for the election of two directors to serve until the terms stated in the Proxy Statement (until the 2013 Annual Meeting of Shareholders and until their successors are elected or appointed and qualified). With respect to the election of the directors, the votes cast were as follows:

Name of Director	Votes For	Withheld
Mark J. Larsen	7,268,168	635,362
Stephen V. Conrad	7,322,244	581,286

The directors now are Keith G. Larsen, Mark J. Larsen, Robert Scott Lorimer, H. Russell Fraser, Allen S. Winters, Stephen V. Conrad and Michael Feinstein.

The shareholders also voted on the ratification of appointment of Hein & Associates LLP, the votes cast were as follows:

	Votes For	Votes Against	Abstain
Ratification of appointment of Hein & Associates LLP as independent auditors for the current fiscal year.	19,291,602	551,196	79,737

PART II

Item 5 - Market for Registrant's Common Equity, Related Stockholder Matters, and Issuer Purchase of Equity Securities

Market Information

Shares of USE common stock are traded on the over-the-counter market, and prices are reported on a "last sale" basis on the Nasdaq Capital Market of the National Association of Securities Dealers Automated Quotation System ("Nasdaq"). Quarterly high and low sale prices follow:

	High	Low
Calendar year ended December 31, 2010		
First quarter ended 03/31/10	$ 6.76	$ 5.14
Second quarter ended 06/30/10	7.06	4.67
Third quarter ended 09/30/10	5.43	4.01
Fourth quarter ended 12/31/10	6.17	4.37
Calendar year ended December 31, 2009		

First quarter ended 03/31/09	$ 2.09	$ 1.54
Second quarter ended 06/30/09	2.57	1.79
Third quarter ended 09/30/09	4.21	1.87
Fourth Quarter through 12-31-09	6.79	3.65

Holders

At March 9, 2011 the closing market price was $6.19per share. There were approximately 1,627 shareholders of record, with 26,418,713 shares of common stock issued and outstanding at December 31, 2010.

We paid a onetime special $0.10 per share cash dividend to common shareholders of record on July 6, 2007. There are no contractual restrictions on our present or future ability to pay cash dividends.

Issuance of Securities in 2010

During the twelve months ended December 31, 2010, USE issued a total of 649,897 shares. A brief discussion of the issuance of the shares follows:

Registered Securities

During the twelve months ended December 31, 2010, we issued 275,728 shares of common stock as a result of the exercise of options which had been issued to employees, 15,000 shares as a result of the exercise of warrants issued to a director and 236,367 shares as a result of the exercise of warrants which had been issued to two consultants. We also issued 42,802 shares pursuant to the terms of our ESOP. The ESOP funding represents the minimum required amount during the twelve months ended December 31, 2010.

The Company has an active registration statement for $100 million. During December 2009 we raised $26.2 million under this registration statement by issuing 5 million shares. A balance of $73.8 million is available under the registration statement which may be used in the future.

Unregistered Securities

During the twelve months ended December 31, 2010, we issued 80,000 shares pursuant to the 2001 Stock Award Plan, 20,000 shares to each of the executive officers of the Company.

Equity Plan Compensation Information - Information about Compensation Plans as of December 31, 2010

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensaiton plans (excluding securities reflected in column (a)) (c)
Equity Companeation plans approved by security holders			
1998 Stock Option Plan	10,000	$ 2.40	--
2001 Incentive Stock Option Plan	3,001,647	$ 3.87	3,765,506
2001 Stock Compensation Plan	(1)	(1)	(1)
2008 Stock Option plan for U.S. Energy Corp. Independent Directors and Advisory board members	120,000	$ 2.73	150,686
Equity compensation plans not approved by security holders	--	$ --	--
Total	3,131,647	$ 3.83	3,916,192

(1) Four Officers (CEO, COO, CFO and General Counsel) of the Company receive 5,000 shares of common stock at the beginning of each calendar quarter, 20,000 shares per year under this plan. The Company pays the taxes on these shares as the Officers have agreed to not pledge, sell or in any other way leverage these shares. The shareholders of the Company approved this plan.

Stock Performance Graph

The following graph compares the cumulative return on a $100 investment in our common stock for the five years ended December 31, 2010, to that of the cumulative return on a $100 investment in the S&P 500, the NASDAQ Market Index, and the S&P Small Cap 600 Energy Index. In calculating the cumulative return, we assumed reinvestment of the $0.10 per share cash dividend paid in July 2007. The indices are included for comparative purpose only. This graph is not "soliciting material," is not deemed filed with the SEC and is not to be incorporated by reference in any of our filings under the Securities Act of 1933 or the Exchange Act, whether made before or after the date the Annual Report was filed and irrespective of any general incorporation language in any such filing.

COMPARISON OF CUMULATIVE TOTAL RETURN AMONG U.S. ENERGY CORP., THE S&P 500, THE NASDAQ MARKET INDEX, AND THE S&P SMALL CAP 600 ENERGY INDEX

ITEM 6. SELECTED FINANCIAL DATA

The selected financial data is derived from and should be read with the financial statements included in this Report.

	(In thousands)				
	December 31,				
	2010	2009	2008	2007	2006
Current assets	$ 29,824	$ 62,100	$ 72,767	$ 82,729	$ 43,325
Current liabilities	18,763	8,672	19,983	8,093	11,595
Working capital	11,061	53,428	52,784	74,636	31,730
Total assets	156,016	146,723	142,631	131,404	51,901
Long-term obligations(1)	1,150	973	1,870	1,283	882
Shareholders' equity	130,688	129,133	111,833	115,100	37,468

(1) Includes $303,000 of accrued reclamation costs on properties at December 31, 2010, $211,000, at December 31, 2009, $144,000, at December 31, 2008, $133,000, at December 31, 2007, and $124,000 at December 31, 2006.

(In thousands except per share amounts)

For the year ended December 31,

	2010	2009	2008	2007	2006
Operating revenues	$ 27,176	$ 10,349	$ 2,222	$ 1,174	$ 880
Loss from continuing operations	(4,232)	(9,271)	(9,604)	(14,539)	(14,668)
Other income & (expense)	1,722	(1,186)	(17)	108,824	2,118
(Loss) income before minority interest, income taxes and discontinued operations	(2,510)	(10,457)	(9,621)	94,285	(12,550)
Minority interest in loss (income) of consolidated subsidiaries	--	--	--	(3,551)	88
Benefits from (provision for) income taxes	1,738	2,279	3,326	(32,367)	15,332
Discontinued operations, net of tax	--	--	4,907	(2,004)	(1,819)
Net (loss) income	$ (772)	$ (8,178)	$ (1,388)	$ 56,363	$ 1,051
Per share financial data					
Operating revenues	$ 1.02	$ 0.48	$ 0.10	$ 0.06	$ 0.05
Loss from continuing operations	(0.16)	(0.43)	(0.41)	(0.71)	(0.79)
Other income & expenses	0.06	(0.05)	--	5.32	0.11
(Loss) income before minority interest, income taxes and discontinued operations	(0.09)	(0.48)	(0.41)	4.61	(0.68)
	--	--	--	(0.17)	--

Minority interest in loss (income) of consolidated subsidiaries					
Benefits from (provision for) income taxes	0.06	0.11	0.14	(1.58)	0.83
Discontinued operations, net of tax	--	--	0.21	(0.10)	(0.10)
Net (loss) income per share basic	$ (0.03)	$ (0.38)	$ (0.06)	$ 2.75	$ 0.06
Net (loss) income per share diluted	$ (0.03)	$ (0.38)	$ (0.06)	$ 2.54	$ 0.05
Basic shares outstanding	26,763,995	21,604,959	23,274,978	20,469,846	18,461,885
Diluted shares outstanding	26,763,995	21,604,959	23,274,978	22,189,828	21,131,786

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULT OF OPERATIONS

Forward Looking Statements

Statements in this discussion about expectations, plans and future events or conditions are forward looking statements. Actual future results, including oil and natural gas production growth, financing sources, and environmental and capital expenditures, could be materially different depending on a number of factors, such as: commodity prices, political or regulatory events, and other matters. Please see "Cautionary Statement Regarding Forward-Looking Statements" and Item 1A in this Report, which should be carefully considered in reading this section.

General Overview

U.S. Energy Corp. ("U.S. Energy" or "Company") historically invested in mineral properties and sold them prior to placing them into production. Beginning in 2008, the Company began investing primarily in oil and gas properties and expending the amount of capital necessary to place them into production with the intent of generating recurring cash flows, revenues and net income.

The Company is now, predominantly, an oil and gas exploration and production company. Our primary objective is to acquire and develop oil and gas producing properties in the continental United States. Our business is currently focused in the Rocky Mountain region (specifically the Williston Basin of North Dakota and Montana and Anadarko Basin of Colorado), Texas, Louisiana and California, however, we do not intend to limit our focus to these geographic areas. We continue to focus on increasing production, reserves, revenue and cash flow from operations while managing our level of debt. Our liquidity and access to financing under our Senior Secured Revolving Credit Facility (see Liquidity and Capital Resources below) allows us to seek additional oil and gas opportunities in the U.S.

We currently explore for and produce oil and gas primarily through a non-operator business model; however, we expect to operate our Colorado property for our own account in 2011. As a non-operator, we rely on our operating partners to propose, permit and manage wells. Before a well is spud, the operator is required to provide all oil and gas interest owners in the designated well unit the opportunity to participate in the drilling costs and revenues of the well on a pro-rata basis. After the well is completed, our operating partners also transport, market and account for all production.

Additionally, we are involved in the exploration for and development of minerals (molybdenum) through our ownership of the Mt. Emmons project in Colorado, geothermal energy through our investment in Standard Steam Trust and commercial real estate operations. Capitalized dollar amounts invested in each of these areas at December 31, 2010 and December 31, 2009 were as follows:

	(In thousands) December 31, 2010	December 31, 2009
Unproved oil and gas properties	$ 21,620	$ 5,361
Proved oil and gas properties	$ 63,317	$ 24,595
Undeveloped mining properties	$ 21,077	$ 21,969

Investment in geothermal properties	$	2,834	$	2,958
Commercial real estate	$	23,084	$	24,600
	$	131,932	$	79,483

Oil & Gas

In 2010, we recognized record revenues from oil and natural gas production of $26.5 million, production of 448,855 BOE and oil and gas proved reserves, at December 31, 2010, of 1,954,941 BOE. The key drivers to our success for 2010 included the following:

Drilling programs. Our success is largely dependent on the results of our drilling programs. During the year ended December 31, 2010, we drilled 13 gross wells (3.33 net wells) with a success rate of 62% that was comprised of: (a) seven of seven gross wells (2.41 net wells) in the Williston Basin, and (b) one gross (0.53 net wells) of six gross wells (0.92 net wells) in the Gulf Coast and Texas drilling programs. At December 31, 2010, 6 additional gross wells (1.51 net wells) were awaiting completion (5 gross wells (1.46 net wells) in the Williston Basin and 1 gross well (0.05 net wells) in the onshore Gulf Coast area.

Reserve growth. As a result of our drilling programs discussed above, our reserves increased 80% to 1,954,941 BOE at December 31, 2010, replacing 193% of 2010 production.

Production. Our 2010 annual production of 448,855 BOE, or 1,230 BOE/d, was a record high for the Company. The 2010 production increased 173% from 2009 production of 164,396 BOE or 450 BOE/d, primarily due to production from the Williston Basin.

Financial flexibility. In July 2010, we improved our financial flexibility through establishment of a senior credit facility to borrow up to $75 million from a syndicate of banks, financial institutions and other entities, including BNP Paribas (“BNP”). In October 2010, the Borrowing Base increased from the initial $12.0 million to $18.5 million as a result of a redetermination using our June 30, 2010 financial statements, production reports and a reserve report for our Williston Basin wells. See Capital Resources - BNP Paribas Reserve Lending Facility below.

Commodity prices. Our average realized oil price in 2010 was $72.11 per Bbl (excluding the impact of our economic hedges), or $5.89 higher than in 2009. Our average natural gas price realized during 2010 was $4.96 per Mcf, $0.66 per Mcf higher than the 2009 price of $4.30. Commodity prices are affected by changes in market demand, overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. Our financial results are significantly dependent on commodity prices, particularly oil prices, which are beyond our control and have been and are expected to remain volatile.

In 2010, through our wholly-owned affiliate Energy One LLC (“Energy One”), we entered into three commodity derivative contracts (“hedges”) with BNP Paribas, a costless collar and two fixed price swaps. U.S. Energy is a guarantor of Energy One under the hedges. The objective of utilizing the hedges is to reduce the effect of price changes on a portion of our future oil production, achieve more predictable cash flows in an environment of volatile oil and gas prices and to manage our exposure to commodity price risk. The use of these derivative instruments limits the downside risk of adverse price movements. However, there is a risk that such use may limit our ability to benefit from favorable price movements. Energy One may, from time to time, add incremental derivatives to hedge additional production, restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of the its existing positions.

Other

Minerals (molybdenum). Our investment in the Mt. Emmons project in Colorado is a long term investment. In 2008, we entered into an Option Agreement with Thompson Creek Metals Company USA ("TCM") under which TCM may acquire up to 75% ownership of the Mt. Emmons project after expending $400 million.

Real estate. We continue to receive cash flows, revenues and net profits from our energy related multifamily housing development in northeastern Wyoming. We do not plan to build or acquire any additional multifamily housing projects.

Geothermal. We own a 22.8% interest in a geothermal limited partnership, Standard Steam Trust, LLC ("SST"). Due to the sale of two of SST's geothermal properties in 2010, we recorded an equity gain from SST in 2010 of $1.0 million, however, equity losses from the investment in SST are expected until such time as additional SST properties are sold, equity losses reduce the investment to zero or we sell the investment. Our net investment in this partnership at December 31, 2010 is $2.8 million.

The principal factors affecting the Company are the success of its oil and gas exploration activities, commodity prices, drilling and completion costs, lease operating expenses, decline rates of our wells, mechanical and geological issues with our wells, the grade of mineral deposits, permitting and costs associated with exploration and development of the prospects.

Liquidity and Capital Resources

We maintained a strong liquidity position throughout the year ended December 31, 2010, notwithstanding significant investment into our oil and gas properties. The Company experienced $12.4 million in cash flow from operations and reduced its debt while maintaining strong liquidity ratios and cash balances. The following table sets forth key liquidity measures for the year ended December 31, 2010 as compared to the year ended December 31, 2009:

	(in thousands)	
	December 31, 2010	December 31, 2009
Current ratio(1)	1.59 to 1	7.16 to 1
Working capital(2)	$ 11,061	$ 53,428
Total debt	$ 600	$ 800
Total cash and marketable securities less debt	$ 24,617	$ 55,840
Total stockholders' equity	$ 130,688	$ 129,133
Total liabilities to equity	0.19 to 1	0.14 to 1

(1)Current assets divided by current liabilities
(2)Current assets less current liabilities

Our strong working capital position and current ratio are the result of conservative investment strategies which are expected to yield revenues, cash flow and net income in the future. As of December 31, 2010, our only debt is related to the acquisition of a property near the Mt. Emmons project. Additional sources of capital that may be used to expand operations include borrowings pursuant to our credit facility with BNP, long-term financing and sale of the multifamily housing complex and a $10 million line of credit with a commercial bank.

Components of the $42.4 million decrease in working capital for the years ended December 31, 2010 from working capital at December 31, 2009 are as follows:

	(In thousands)		
	December 31, 2010	December 31, 2009	Increase