US ENERGY CORP
Form 10-K
March 12, 2010

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, 2009

¨ 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 ¨ Non-accelerated filer þ

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, 2009): $40,215,356.

Class	Outstanding at March 11, 2010
Common stock, $.01 par value	26,499,324

Documents incorporated by reference: None.

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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; our business strategy and plans to build an asset base that generates recurring revenues; 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 Brigham Exploration Company in the Bakken/Three Forks formations; 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 Mount Emmons and the expected length of time to permit and develop the Mount Emmons project; expected time to receive a return on investment from the geothermal prospects; continuing investment through capital calls and potential dilution of current ownership interest with Standard Steam Trust LLC; future cash flows and borrowings; pursuit of potential acquisition opportunities; anticipated business activities in the Gillette, Wyoming area and their impact on occupancy rates for the 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 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;

- future oil and natural gas production rates, and/or the ultimate recoverability of reserves, falling below prior estimates;

    - the ability to replace oil and natural gas reserves as they deplete from production;

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- environmental risks;
- availability of pipeline capacity and other means of transporting crude oil and natural gas production; and
- competition, including competition in lease acquisitions, and for participation in drilling programs with operating companies, resulting in less favorable terms for participation.

For the molybdenum property:

- the ability to obtain permits required to initiate mining and processing operations, and Thompson Creek Metals' 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.

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.

For geothermal activities:

- the ability to acquire additional BLM and 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 to access third-party capital to reduce reliance on capital calls to its members (including U.S. Energy Corp.) for continued operations; and
- the ability to access sufficient capital to develop geothermal properties.

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.

PART I

Item 1 - Business

Overview

U.S. Energy Corp., a Wyoming corporation organized in 1966, acquires and develops oil and gas and other mineral properties. Our corporate objective is to diversify capital investments in oil and gas, while proceeding with long-term development of our molybdenum property in Colorado and our geothermal properties. Historically, we have undertaken early stage development of various natural resource projects, and after advancing the projects, we have entered into partnership arrangements or have sold all or portions of those projects which have typically allowed us to realize value for shareholders. This strategy has resulted in several years of relatively low operating revenues, but in certain years we have realized substantial gains from disposition of these projects.

For 2010 and subsequent years, we are seeking to increase recurring revenues from oil and gas production. Simultaneously, we intend to advance our geothermal properties through exploration and development, and eventual third party funding, sale or joint venture, and advance our molybdenum property by working with our partner, Thompson Creek Metals Company (USA) to develop the Mount Emmons molybdenum project into a major operating mine. We completed a multifamily apartment project serving the residential market in Gillette, Wyoming in 2008, and it is generating positive cash flow. We do not intend to make more investments in the real estate housing sector.

Industry Segments/Principal Products

At December 31, 2009, 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 Strategy and Activities

From 2005 through 2008, we generated substantial cash proceeds from selling our interests in our coalbed methane and uranium businesses, and most of our stock in a gold company. Utilizing a portion of these proceeds, we:

- initiated investment activities with three separate oil and gas industry partners in 2008 and with two others in 2009, including entering into a Drilling Participation Agreement with a subsidiary of Brigham Exploration Company (NASDAQ Global Select Market: BEXP);

- Negotiated an agreement with a subsidiary of Thompson Creek Metals Company Inc. (NYSE:TC), a major molybdenum mining and refining company, which provides for Thompson Creek Metals Company (USA) ("TCM") investing substantial sums to earn up to a 75% interest in our Mount Emmons molybdenum property in Colorado;

- invested in the geothermal sector by acquiring a minority interest in Standard Steam Trust, LLC; and

- constructed an apartment complex in Gillette, Wyoming.

Oil and Gas

At December 31, 2009, our estimated proved reserves (approximately 75% oil and 25% natural gas) were 1,086,203 BOE, with a standardized measure of $19,984,000 and a present value before taxes (discounted at ten percent, ("PV10")) of $25,760,000. Reflecting our commencement of drilling in the Williston Basin with Brigham Exploration Company in August 2009, this represents a 602% increase over the $3,318,000 standardized measure of proved reserves, and a 485% increase over PV10 at December 31, 2008.

PV10 is widely used in the oil and gas industry, and is followed by institutional investors and professional analysts, to compare companies. However, the PV10 data is not an alternative to the standardized measure of discounted future net cash flows calculated under GAAP and includes the effects of income taxes. The following table provides a reconciliation of Estimated Future Net Revenues Discounted at 10% to the Standardized Measure of Discounted Future Net Cash Flows as shown in Note F to the Company's Consolidated Financial Statements.

	(In thousands) At December 31,		
	2009	2008	2007
Standardized measure of discounted net cash flows	$ 19,984	$ 3,318	$ --
Future income tax expense (discounted)	5,776	1,993	--
PV10	$ 25,760	$ 5,311	$ --

Average production in 2009 was 443 BOE/D (220 barrels of oil and 1,337 Mcf/D), an increase of 1,107% over the average 40 BOE/D in 2008. Substantially all of the increased production in 2009 is attributable to the six wells drilled and completed in the Williston Basin with Brigham in the fourth quarter.

As of February 22, 2010, daily production from all of our wells was approximately 700 barrels of oil and 1,780 Mcf (995 BOE/D). Initial production (on a BOE/D basis) from the 6 Williston Basin wells was in the range of 85% oil and 15% natural gas. The percentage of oil is expected to increase in the initial six-month production period for each of these wells, as gas production declines.

Activities with Operating Partners in Oil and Gas

We currently have active oil and gas investment activities structured with four third-party operating partners. These investments relate primarily to the drilling and completion of oil and gas wells, and to a limited extent, in seismic and other early stage activities leading to the identification of further drilling prospects. Thus far, we have entered into these drilling ventures with oil and gas operating companies that have records of successfully acquiring prospects and drilling and completing oil and gas wells utilizing their technical staff to identify prospects. We have chosen to allow these third parties to operate all of our current oil and gas properties, believing that these arrangements allow us to deliver value to our shareholders without our having to invest the time and capital to build our own team of geophysical, engineering and other technical personnel, and acquiring our own large acreage positions. We believe our finding costs per unit of oil and gas discovered will benefit from these cost savings. In the future, we may enter into other arrangements, or even acquire operating companies, which may involve hiring our own technical staff and possibly becoming operator on certain projects.

Existing oil and gas projects with our operating partners are as follows:

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 can earn working interests, out of Brigham’s interests, in up to fifteen 1,280-acre spacing units in Brigham’s Rough Rider project area, which is located in Williams and McKenzie Counties, North Dakota. As of December 31, 2009, six of the initial wells have been completed and are producing. At March 1, 2010, three wells were in the drilling and/or completion stages. By electing to participate in all of the initial wells available to us, we have earned the rights to drill up to 30 total wells in the Bakken formation and an additional 30 wells in the Three Forks formation, for a total of 60 wells, based on current spacing rules in North Dakota. If the spacing is ultimately increased to three wells per 1,280 acre spacing unit, the potential number of drilling locations could increase to 90. Working interests earned will 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.

We will earn working interests in up to 15 spacing units (approximately 1,280 acres each – two sections of 640 acres each) by participating in drilling up to 15 initial wells (one per unit). All the wells are expected to be horizontal wells, of moderate vertical depth (in the range of 10,000 feet) with long laterals (up to approximately 10,000 feet), each with approximately 28 to 32 fracture stimulation stages. The DPA expires on December 31, 2010; however, we will continue to hold the working interests we earn prior to expiration. 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.

Our earn-in rights are staged in three groups of units, and will be 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.

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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: In the fourth quarter of 2009, we drilled the six initial wells in the First Group to earn 65% of Brigham's initial working interest in six 1,280 acre units. As of the date this Annual Report was filed, all six wells have been completed and are producing oil and gas; oil is being sold, and gas is being sold or flared pending installation of gathering lines to hook up the wells to transmission lines.

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.

When each initial well was completed, 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 the units. 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.

Second Group: In accordance with the DPA, following receipt from Brigham of initial 24-hour production reports (the "IP Reports") from the first four of the six initial wells in the First Group, we elected to participate in the drilling 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. In accordance with the DPA, we elected to take the remaining 50% of the working interest available to Brigham.

When each initial well in the Second Group is completed (or plugged and abandoned, if applicable), U.S. Energy will have earned working interests to all the acreage in the applicable unit. 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. As of March 1, 2010, we have drilled 3 of the initial wells in the Second Group with Brigham, and earned working interests in 3 of the four units.

Third Group: The DPA provides us the right to participate in the Third Group's five initial wells, on an all-or-none basis, if we have participated in the Second Group, and we provide Brigham a participation notice for the Third Group within ten days of receiving an IP Report for the sixth initial well in the First 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.

When each initial well in the Third Group is completed (or plugged and abandoned, if applicable), we will have earned 36% of Brigham's initial working interest in all the acreage in the applicable unit (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. As of the date this Annual Report was filed, we have not drilled any initial wells in the Third Group with Brigham.

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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. Pursuant to the DPA, neither we nor Brigham may propose the drilling of a subsequent well (unless necessary for lease maintenance purposes) before January 1, 2011 unless the parties mutually agree to do so.

Texas and Louisiana

With PetroQuest Energy, Inc. Two wells have been drilled in coastal Louisiana with PetroQuest (NYSE: PQ); one is producing natural gas and oil (we have a 14% working interest and a 9.76% net revenue interest), and the other well drilled with PetroQuest was a dry hole. We expect to drill up to five more wells with PetroQuest in 2010, and expect our working interest participation to be in the range of 4.2% to 20%. At payout (plus 6% annual interest) from each of our producing wells with PetroQuest, we will assign 15% of our working interest to a third-party consultant, and an additional 5% at 200% of payout.

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, and we expect that Yuma will recommend drilling at least six prospects in 2010. 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. We anticipate participating in at least 6 wells with Yuma in 2010.

U.S. Energy holds a 4.79% working interest, Yuma owns an approximate 48% working interest, and the balance (approximately 47.21%) is held by third parties program. 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 (total $1,390,000), 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. We have participated with Houston Energy in drilling three wells in Southeast Texas and Louisiana; two are producing (we have 8.5% and 25% working interests (6.23% and 17.625% net revenue interests)) and one well was a dry hole. At payout we will assign to a third party consultant 12.5% of our working interest in each producing well. We expect to participate in 3 additional wells with Houston Energy in 2010.

Going Forward

In 2010 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 purchase and exploration of new acreage positions.

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 in Mount Emmons.

The Option Period:

TCM paid us $500,000 at closing (not refundable), and paid the first two $1.0 million option payments on January 2, 2009 and December 30, 2009. TCM has the option to pay us an additional four annual payments of $1.0 million each beginning on January 1, 2011 for the option.

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 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

Costs to operate the water treatment plant at the property will be 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

On December 17, 2008, we bought a 25% minority interest for $3.5 million in Standard Steam Trust, LLC (“SST”), a Denver, Colorado-based private geothermal resource acquisition and development company. At December 31, 2009, our investment was $3.0 million after recognizing an equity loss of $1.4 million at December 31, 2009. As a result of our election to not participate in a December, 2009 capital call our percentage ownership has been reduced to 23.8%. SST’s capitalization as of December 31, 2009 was $18.2 million. Its assets now include four advanced stage and four early stage geothermal projects in the western United States, located on over 102,000 acres of BLM, state and fee land in eight prospect areas in three states. SST is managed by Terra Caliente, LLC (“Terra”), also a private Denver-based company, with oversight by an advisory board (U.S. Energy is one of three members) as to budgets, major expenditures, sale or other disposition of prospects and similar matters. Terra will receive a back-in interest of 25%, along with other members (but not U.S. Energy), at such time as all other investors (including Terra) receive cash distributions or securities equal to their investment.

SST intends to advance each individual prospect through the exploration and feasibility stages before determining whether to: (i) sell a prospect to a utility, (ii) bring an industry partner on a joint venture basis, or (iii) pursue further financing with institutional capital to further advance revenue generating capabilities, which may include the operation of power plants. The first phase of the project is assembling a portfolio of industrial scale prospects with an initial targeted power resource of approximately 1,000 MW; individual prospects are targeted at 100 to 500 MW. The second phase, consisting of early science of geology, geophysics and temperature gradient drilling, has commenced and is expected to continue in 2010 and thereafter, followed by production well drilling on at least one of the prospects during 2010 –2011 to quantify the geothermal resource.

Real Estate

At year end 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 80% at December 31, 2009.

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 continued credit crisis and related turmoil in the global financial system may have a material impact on our ability to finance the purchase of producing or exploratory oil and gas properties. The availability of credit to our industry partners may also affect their ability to generate new exploration and development prospects. The current economic situation could also cause our partners to fail 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, the current economic situation could lead to reduced demand for natural gas and oil, or further reductions in the prices of natural gas and oil, or both, which could have a negative impact on our financial position, results of operations, and cash flows.

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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.

With the stated aims (among others) of fostering a clean energy economy and reducing reliance on fossil fuels that contribute to climate change, the Federal budget for fiscal 2011 published by President Obama’s administration includes 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.

On June 26, 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 is 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 has begun work on its own legislation for controlling and reducing emissions of GHGs in the United States. If the Senate adopts GHG legislation that is different from ACESA, the Senate legislation would need to be reconciled with ACESA and both chambers would be required to approve identical legislation before it could become law. The U.S. Environmental Protection Agency, or EPA, is also separately undertaking a rulemaking process to determine whether GHGs will be designated as “pollutants” under the existing Federal Clean Air Act. President Obama has indicated that he is in support of the adoption of legislation to control and reduce emissions of GHGs through an emission allowance permitting system that results in fewer allowances being issued each year but that allows parties to buy, sell and trade allowances as needed to fulfill their GHG emission obligations. Although it is not possible at this time to predict whether or when the Senate may act on climate change legislation or the EPA or analogous state agencies may adopt climate change regulations, or how any bill approved by the Senate or any regulation approved by the EPA would be reconciled with ACESA, any laws or regulations that may be adopted to restrict or reduce emissions of GHGs would likely require us to incur increased operating costs, and could have an adverse effect on demand for the oil and natural gas we produce.

Limited recurring business revenues may constrain future investments, and earnings will continue to be influenced by transaction events.

At December 31, 2009, USE had $9.5 million in retained earnings, and a loss from operations (before investment and property transactions) of $9.3 million. At December 31, 2008, we had $17.7 million in retained earnings, a loss from operations (before investment and property transactions) of $9.5 million. During 2008 and 2009 we began modifying our business to build an asset base that generates recurring revenues and cash flows. We have initiated this goal by entering into the oil and gas business. We expect our other businesses to continue to experience fluctuations in revenues and cash flows as projects like our Mount Emmons molybdenum and geothermal investment are mid to long-term projects which are capital intensive and take years to develop.

Working capital constraints may limit our ability to develop, or to fund our current share in the development of, our mineral, oil and gas and geothermal properties.

Working capital at December 31, 2009 and December 31, 2008 was $53.4 million and $52.8 million, respectively. We were able to maintain our working capital level primarily as a result of selling 5 million shares of our common stock in a public offering during December 2009 for net proceeds (after expenses) of $24.3 million. While this represents a strong position of liquidity, we do not have sufficient capital to fully develop our oil and gas, mineral and oil and gas properties. 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 drilling 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.

- Further investments of cash into the geothermal program may be required to maintain our interest and bring the properties to a stage of development where they can be sold or joint ventured with an industry partner. Any return on the investment may not be realized for three to five years or longer. To the extent additional capital is not obtained from third parties, cash to sustain operations will have to be raised from the sale of properties or from current members in Standard Steam Trust LLC (including U.S. Energy Corp.) through capital calls, in which event the cash required to maintain our percentage interest could be substantial. Failure to fund cash calls will dilute our position.

- We are paying the annual costs (approximately $1.6 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. If Thompson Creek Metals elects 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 the development and operating costs.

We believe that we have sufficient cash reserves to execute our business plan in 2010 and subsequent years, assuming our various projects generate revenues as projected. However, adverse developments in one or more programs would require a reassessment of priorities and therefore potential re-allocations of capital. If internal cash from current reserves and projected revenues are insufficient, we may have to obtain investment capital to maintain the full range of activities. Additional capital also could be required to expand activities in oil and gas beyond the programs now in place.

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 opportunities to partner with (or acquire) established oil and gas operations. 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 is subject to risks related to horizontal drilling and completion techniques.

Operations in the Williston Basin 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.

The results of our drilling program in the Williston Basin are subject to more uncertainties than drilling in more established formations in other areas.

Brigham has only recently begun drilling wells 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. Brigham's experience as well as the industry's drilling and production history in the formation generally are limited. The ultimate success of these drilling and completion strategies and techniques in these formations 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 drill with Brigham may not be replicated in additional wells, even in the same drilling unit.

Through the date this Annual Report was filed, all the wells we have drilled with Brigham have been drilled into the Bakken formation. Brigham (and other operators) have reported successful completion of Three Forks wells in other parts of the Williston Basin, but Brigham has not drilled any Three Forks wells in the Rough Rider Prospect area. 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. See "Business - Oil and Gas – Williston Basin."

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 into the atmosphere) until the well can be hooked up to a transmission line. Installation of a gathering system can take from 90 to 120 days, or longer depending on well location, weather conditions and availability of service providers. As of the date this Annual Report was filed, three of the wells we have drilled with Brigham have been hooked up to gas transmission lines.

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

We may not be able to participate in all or even a substantial portion of the many locations we earn through the Drilling Participation Agreement with Brigham. 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, 2009 are based on the monthly average price received during the full year period. For the year ended December 31, 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, 2009 and 2008, which were not included in the amortized cost pool, were $5.4 million and $3.0 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, 2009 and 2008, 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, 2009, we used $61.18 per barrel for oil and $3.866 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 in the fourth quarter of 2009 did not exceed the ceiling test limit. Non-cash write downs of $1.5 million for oil and gas properties were recorded during the first three quarters of 2009. As a result of the increased price for oil and gas at December 31, 2009 and additional reserves being developed during the fourth quarter of 2009, no further impairment was taken at December 31, 2009. 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.

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, 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 the future drilling of the acreage in all 15 units under the Drilling Participation Agreement.

Our business may be impacted by adverse commodity prices.

In June of 2008, oil prices spiked to a ten year high with a spot price of $133.88 per barrel. At December 31, 2008, the spot price for oil had declined to $41.12 per barrel. At December 31, 2009, the price had recovered somewhat to $74.47 per barrel. Global markets have caused these large fluctuations in the price of oil. 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. As with oil, the City Gate price for natural gas declined through the balance of 2008 and was $8.16 per Mcf as of December 31, 2008, and $6.24 per Mcf at December 31, 2009. Molybdenum prices have declined from a ten year high 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, 2009 was $11.50 per pound. The global economic recession may continue to suppress prices and prices could drop further. Significant price declines from December 31, 2009 levels 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 conditions;
- 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.

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We do not currently operate any 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.

We do not currently operate or expect to operate any of our currently identified drilling locations. As we carry out our exploration and development programs, we have entered into, and may enter into future arrangements, for our properties to be operated by others. Our objective in not being the operator is to keep overhead low and not have large engineering, geophysical and administrative staffs. By eliminating the overhead, we can react quicker to opportunities as well as conserve cash in budgetary restrictive times.

Allowing others to operate our properties limits our ability to exercise influence over the operations of the drilling programs. The success and timing of exploration and development activities operated by our partners will depend on a number of factors, including:

- the timing and amount of capital expenditures;
- the operator's expertise and financial resources;
- approval of other participants in drilling wells;
- selection of technology; and
- the rate of production, if any.

This limited ability to exercise control over the operations may cause a material adverse effect on our results of operations and financial condition.

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, 2009, 97% of our estimated proved reserves were producing and 3% were proved developed non-producing. 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 2009. 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 did not have any such instruments in place in 2009, but may adopt some in 2010 and/or future years. 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.

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

We may engage in hedging arrangements for a significant part of our production to reduce exposure to price fluctuations in oil and gas prices. These arrangements would expose us to risk of financial loss in some circumstances, including when production is less than expected, the counterparty to the hedging contract defaults on its contract obligations, or there is a change in the expected differential between the underlying price in the hedging agreement and the actual price received. In addition, these hedging arrangements may limit the benefits we would otherwise receive from increases in prices for oil and natural gas. Currently, we have no hedges in place for oil or gas production.

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

Typically, operators obtain a preliminary title opinion or at least a landman’s evaluation of title, prior to drilling. To date, our operators have provided preliminary title opinions prior to drilling. In addition, we rely on the operators to warrant that title is in order and 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.

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”). For example, water and dust discharged from mines and tailings from prior mining or milling operations must be monitored and contained and reports filed with federal, state and county regulatory authorities. Additional monitoring and reporting is required by state and local regulatory agencies. 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. Additionally, our 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. While we did not fund a cash call in December 2009, it may become necessary to continue investing through the partnership’s capital calls. In 2010 and beyond, we may decline any capital call without penalty, and such non-participation would dilute our ownership. At December 31, 2009 we had a 23.8% ownership in SST. Notwithstanding the current increase of interest in geothermal power generally, SST may be unable to raise sufficient capital from new investors due to the condition of the global financial markets. In that event, the project might have less than the optimum number of prospects and/or be unable to establish prospective value through drilling. This could substantially reduce the value of our investment.

All the prospects are undeveloped. Prospect value may only initially be determined by drilling at least three production wells, at substantial expense, on each prospect that demonstrate sufficient water temperature and flow to support a commercial power plant. Even if resources are drilling-validated as to power potential, realization of our investment will depend on the sale of our partnership equity, or the partnership's distribution of proceeds from sale of the properties to a utility, energy company, or other investor, or construction of a power plant (which will require institutional financing) and sale of electricity to utilities.

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 expect to submit a Plan of Operations to the USFS in 2010 for USFS approval, which must be approved before initiating construction, and mining and processing can occur. 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 and/or an Environmental Impact Statement to evaluate the predicted environmental and socio-economic impacts of the proposed development and mining of the property. 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 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, however this permit may need to be updated.

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 are searching for employees to replace some or all of our third party geophysical and geological consultants. As of the date of the filing of this Annual Report we have not engaged any such employees.

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.

Although we do not presently intend to do so, we may seek to raise capital from the equity markets using private placements at discounted prices, which 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.

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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, 2009, the stock has traded as high as $6.79 per share and as low as $1.52 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; and
- legislative and regulatory changes

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 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) and CGA is a Texas Registered Engineering Firm (F-693). Ryder Scott prepared the estimates related to our Gulf Coast Basin, including Louisiana and Texas properties and CGA prepared the estimates or 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 geological, geophysical and reserve engineering expertise. We therefore primarily rely on the operators of our producing wells who provide production data to our contract reserve engineers. Once the reserve engineers have reviewed all data and established preliminary reserves for the operators of the wells for which we rely on the operator, they also prepare a standalone report for us.

Summary of Oil and Gas Reserves as of Fiscal Year End Based on Average Fiscal-Year Prices (1)

	December 31, 2009	2008	2007
Net proved reserves Oil (Bbls)			
Developed	811,789	29,798	--
Undeveloped	--	--	--
Total	811,789	29,798	--
Natural gas (Mcf)			
Developed	1,502,296	1,000,000	--
Undeveloped	--	--	--
Total	1,502,296	1,000,000	--
Natural gas liquids (Bbls)			
Developed	24,031	--	--
Undeveloped	--	--	--
Total	24,031	--	--
Total proved reserves (BOE)	1,086,203	196,465	--

(1) Reserves for 2009 are based on average prices per barrel of oil and per MMbtu of natural gas at the first of each month in the 12-month period prior to the end of the reporting period.

U.S. Energy has no reserves of synthetic oil or synthetic gas, and does not produce or have reserves of any petroleum products.

As of December 31, 2009, our proved reserves totaled 1,086,203 BOE (100% proved developed), comprised of 811,789 Bbls of oil (75% of the total), 1,502,296 Mcf of natural gas and 24,031 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

We had no proved undeveloped reserves at December 31, 2009.

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,		
	2009	2008	2007
Production Volume			
Oil (Bbls)	80,461	2,330	--
Natural gas (Mcf)	487,978	73,635	--
BOE	161,791	14,603	--
Daily Average Production Volume			
Oil (Bbls/d)	220	6	--
Natural gas (Mcf/d)	1,337	202	--
BOE/d	443	40	--
Oil Price per Bbl Produced			
Realized Price	$ 60.01	$ 36.78	--
Natural Gas Price per Mcf Produced			
Realized Price	$ 4.13	$ 6.59	--
Average Sale Price per BOE (1)	$ 42.30	$ 39.10	
Expense per BOE			
Production costs (2)	$ 2.15	$ 4.26	--
Depletion, depreciation and amortization	$ 22.07	$ 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, 2007 through December 31, 2009. 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		
	2009	2008	2007
Producing			

Gross	--	--	--
Net	--	--	--
Dry			
Gross	--	--	--
Net	--	--	--

	Exploration Wells Drilled		
	2009	2008	2007
Producing			
Gross	8.0000	1.0000	--
Net	3.3286	0.1500	--
Dry			
Gross	2.0000	1.0000	--
Net	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, 2009. 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	7.00	3.24	46.33714 %
Natural Gas	2.00	0.23	11.25000 %
Total (1)	9.00	3.47	38.54000 %

(1) The average working interest for the five Williston Basin wells producing at December 31, 2009 is 49.89%; the remaining three wells (Southeast Texas and Louisiana), have 8.5%, 14%, and 25% 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, 2009.

	Developed		Undeveloped		Total	
Area	Gross	Net	Gross	Net	Gross	Net
Williston Basin Wells with Brigham Exploration	7,680	3,832	2,560	749	10,240	4,581
So. East Texas and Louisiana	1,251	154	89,334	4,408	90,585	4,562
Total	8,931	3,986	91,894	5,157	100,825	9,143

Present Activities

As of March 1, 2010, we were drilling 1 gross (0.2 net) wells in Louisiana (offshore), and in the process of completing 3 gross (0.92 net) wells in the Williston Basin.

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 $125 per claim to the Bureau of Land Management; the total amount paid for claim maintenance fees in 2009 was $126,500, 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.

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.

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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, 2009, TCM has spent approximately $7.6 million on the property. The 2010 TCM budget for the Project is projected to be $8.4 million. Our annual operating cost for the water treatment plant is approximately $1.6 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 State and Federal regulations and availability of capital, which is driven by the market price for molybdenum.

Activities in 2009 and Plans for 2010

TCM, the Project Manager, is currently preparing and evaluating engineering and environmental reports and studies to prepare a Plan of Operations, which we anticipate will be submitted to the USFS in 2010. We expect that the Initial Plan of Operations will facilitate the base line data collection needed for additional permitting efforts. The Initial Plan of Operations review will follow the NEPA process, requiring the collection of environmental baseline data and studies for the preparation of an environmental analysis.

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 $11.29 in 2009, compared to $29.71 in 2008 ($17.79 in the fourth quarter 2008 and $10.00 as of December 31, 2008). The decrease in the average annual price for molybdenum is a result of the global recession which has led to dramatic reductions in steel output and pricing, and correspondingly in market demand for molybdenum and its pricing.

Energy Housing

Remington Village - Gillette, Wyoming. We have built and own a nine building multifamily apartment complex, with 216 units on 10.15 acres (purchased in 2007) 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.

Occupancy averaged 88.6% in 2009. For that year, we realized average monthly revenues of approximately $219,000 (a 7 % return on investment (approximately 6.8% higher than the return realized on our Treasury Bills for the year)). The occupancy rate at December 31, 2008 was 88% and 80% at December 31, 2009. The decrease in occupancy rate from 2008 to 2009 is due to the national economic downturn and reduced activities in the oil and gas sector in Wyoming. Construction of a coal fired power plant 7 miles north of Gillette is expected to continue through 2011. A continued increase in oil and gas and coal mine activities in the area from the modest increases viewed in late 2009 and early 2010 may favorably impact our occupancy rate in 2010 and later years.

In January 2010 we pledged the apartment complex along with our corporate aircraft as collateral for a $10 million commercial line of credit with a financial institution.

In August 2007, Zions Bank provided secured construction financing, which also was guaranteed by U.S. Energy. The loan was $16.8 million at December 31, 2008. Total cost to buy the land, pay a developer's fee, obtain permits and entitlements, site work and construction, was approximately $24.5 million at December 31, 2008, of which $7.7 million cash was invested by us (including $1.2 million for land purchase). The interest rate on the loan balance at December 31, 2008 was 2.71% (payable monthly) based on LIBOR. Loan maturity was March 1, 2009. In January 2009, we paid off the construction financing ($16.8 million) with internal funds. The property currently has no debt, although we may seek further collateral financing for the project in 2010 to provide additional access to capital for our oil and gas activities as warranted.

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. 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; two vacant lots covering 13.2 acres in Fremont County, Wyoming, and two city lots and improvements including one small office building.

On December 28, 2007, we purchased 13.84 acres of undeveloped land across the street from USE's corporate office building for $500,400 cash, with the intention of developing the land for mixed commercial and multifamily residential purposes. Our basis in the property and improvements at December 31, 2009 is $656,300. When the real estate market recovers we intend to sell the property without development. The timing of sale is not known.

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 predicted.

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.

Employees

As of March 11, 2010, we had 18 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, 2009, 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

1. Concerning the Application of the United States of America in the Gunnison River, Gunnison County, Case No. 99CW267. This case involves an application filed by the United States of America to appropriate 0.033 cubic feet per second of water for wildlife use and for incidental irrigation of riparian vegetation at the Mount Emmons Iron Bog Spring, located in the vicinity of Mount Emmons. MEMCO filed a Statement of Opposition to protect proposed mining operations against any adverse impacts by the water requirements of the Iron Bog on such operations. This case is pending while the parties attempt to reach a settlement on the proposed decree terms and conditions.

2. 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 concerning the conditional water rights associated with Mount Emmons. The conditional water decree ("Decree") requires the Company to file its proposed plan of operations and associated permits ("Plan") 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. Although the BLM issued the mineral patents on April 2, 2004, the patents remained subject to a challenge by High Country Citizens' Alliance, the Town of Crested Butte, and the Board of County Commissioners of Gunnison County (collectively "Protestors"). The Company vigorously defended this legal action through the Federal District Court for the District of Colorado and the Tenth Circuit Court of Appeals. 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 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 State of Colorado, and High Country Citizens' Alliance in September 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. Although, the Company and TCM will be prepared to file a Plan by the April 2, 2010 proposed deadline, the Company and TCM will pursue a ruling from the Water Court that the deadline specified in the Decree requires the filing of the Plan by April 30, 2013.

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Ordinance Related to the Crested Butte Watershed

On May 19, 2008, the Town Council adopted a revised Watershed Ordinance. The Company and TCM intend to work with the Town of Crested Butte concerning activities at Mount Emmons consistent with lawful and applicable rules, regulations, and statutes. It is possible that unexpected delays, and/or increased costs, may be encountered in developing a new mine plan for Mount Emmons as a result of the revised Watershed Ordinance.

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

On March 8, 2008, High Country Citizens' Alliance ('HCCA") filed a request for hearing before the Colorado Land Reclamation Board ("Board") of the approval of a Notice of Intent to Conduct Prospecting Notice for the Mount Emmons molybdenum property ("NOI"), which was approved by the Division of Reclamation, Mining and Safety of the Colorado Department of Natural Resources ("DRMS") on January 3, 2008. The NOI as approved provided 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 28, 2008, the Company and the Colorado Attorney General's Office filed independent Motions to Dismiss alleging among other matters that: (i) HCCA had no standing to appeal the NOI; (ii) the NOI is not an appealable decision under Colorado law; (iii) HCCA's appeal is not timely; and (iv) the appeal is based on information obtained in violation of Colorado law.

On May 14, 2008, the Board denied HCCA's Request for Hearing and also denied their Request for a Declaratory Order. Citing Colorado law, the Board 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 Board'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 Board 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. No hearing date has been scheduled in the District Court of Colorado concerning DRMS's issuance of the NOI to the Company for the Mount Emmons molybdenum property.

Water Treatment Facility – Permit Renewal Protest

The Company received a NPDES Permit renewal for Mount Emmons from the Colorado Department of Public Health and Environment – Water Quality Division ("Water Quality Division") effective September 1, 2008. The NPDES Permit is for a five (5) year period (2008 - 2013). On August 28, 2008, the Town of Crested Butte, Board of County Commissioners for the County of Gunnison and High Country Citizens' Alliance ("Petitioners") filed a Request for Adjudicatory Hearing before the Water Quality Division to challenge the NPDES Permit. The Petitioners seek revisions to the Permit that would require the Company to maintain a prepaid operating contract and provide additional financial security for long term operation of the plant.

A hearing before the Administrative Law Judge ("ALJ") in the Office of Administrative Courts was held on October 2, 2009 in Denver, Colorado. On October 30, 2009 the ALJ issued an order upholding the issuance of the NPDES Permit and rejecting the Petitioners request for financial assurances as a condition of the NPDES permit.

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

On June 26, 2009, 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 2012 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
Keith G. Larsen	16,525,397	322,997
Allen S. Winters	16,449,761	398,633

The directors now are Keith G. Larsen, Mark J. Larsen, Robert Scott Lorimer, H. Russell Fraser, Allen S. Winters, Michael T. Anderson 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.	14,482,178	214,537	42,203

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, 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 ended 12/31/09	6.79	3.65
Calendar year ended December 31, 2008		
First quarter ended 03/31/08	$ 4.45	$ 3.17
Second quarter ended 06/30/08	3.30	2.42
Third quarter ended 09/30/08	3.27	1.87
Fourth quarter ended 12/31/08	2.60	1.52

Holders

At March 11, 2010 the closing market price was $6.41 per share. There were approximately 2,132 shareholders of record, with 26,418,713 shares of common stock issued and outstanding at December 31, 2009.

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 2009

During the twelve months ended December 31, 2009, USE issued a total of 5,189,655 shares and cancelled 706,071 shares. A brief discussion of the issuance of the shares follows:

Registered Securities

During the twelve months ended December 31, 2009, we issued 1,984 shares of common stock as a result of the exercise of options which had been issued to an employee and 71,088 shares as a result of the exercise of warrants which had been issued to two consultants. We also issued 36,583 shares pursuant to the terms of our ESOP. The ESOP funding represents the minimum required amount during the twelve months ended December 31, 2009.

In December 2009, we issued 5 million shares of common stock in a public offering, for gross proceeds of $26.2 million. These securities were offered and sold under a universal shelf registration statement on Form S-3 (SEC File No. 333-162607), declared effective on November 6, 2009. Madison Williams and Company LLC acted as Sole Book-Running and Lead Manager for the public offering (which commenced on December 1, 2009) of the 5 million shares, and C.K. Cooper & Company acted as Co-Manager. The registration statement covers $100 million. Additional shares may be sold under this registration statement in the future.

From November 6, 2009 through December 31, 2009, we paid a total of $1.9 million for underwriting discounts and commissions, expenses paid to or for the underwriters, and other expenses (including printing, legal and audit fees and costs, travel, and related items). Net proceeds to U.S. Energy from the public offer and sale of the 5 million shares was $24.3 million.

As of December 31, 2009, none of the net proceeds had been used. We anticipate using net proceeds in 2010 for oil and gas exploration and development costs and general working capital.

Unregistered Securities

During the twelve months ended December 31, 2009, we issued 80,000 shares pursuant to the 2001 Stock Award Plan, 20,000 shares to each of the executive officers of the Company.

Cancellation of Shares

During the twelve months ended December 31, 2009, the Company completed its Stock Buyback Program by purchasing and cancelling 706,071 shares at a cost of $1.4 million. The program purchased and cancelled a total of 3,094,200 shares at a cost of $8.0 million during 2007, 2008 and 2009.

Equity Plan Compensation Information - Information about Compensation Plans as of December 31, 2009

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	434,215	$ 2.40	--
2001 Incentive Stock Option Plan	3,276,899	$ 3.80	3,327,779
2001 Stock Compensation Plan	(1)	(1)	(1)
2008 Stock Option plan for U.S. Energy Corp. Independent Directors and Advisory board members	130,000	$ 2.52	81,351
Equity compensation plans not approved by security holders	--	$ --	--
Total	3,841,114	$ 3.60	3,409,130

(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, 2009, 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 except per share data) Years ended December 31,				
	2009	2008	2007	2006	2005
Current assets	$ 62,100	$ 72,767	$ 82,729	$ 43,325	$ 7,841
Current liabilities	8,672	19,983	8,093	11,595	1,232
Working capital	53,428	52,784	74,636	31,730	6,609
Total assets	146,723	142,631	131,404	51,901	38,107
Long-term obligations(1)	1,573	1,870	1,283	882	7,950
Shareholders' equity	129,133	111,833	115,100	37,468	26,027

(1)Includes $211,000 of accrued reclamation costs on properties at December 31, 2009, $144,100 at December 31, 2008, $133,400 at December 31, 2007, $124,400 at December 31, 2006, and $5,669,000 at December 31, 2005. See Note M of Notes to Financial Statements

	For the years ended December 31,				
	2009	2008	2007	2006	2005
Operating revenues	$ 9,627	$ 2,287	$ 1,174	$ 880	$ 850
Loss from continuing operations	(9,256)	(9,521)	(14,539)	(14,668)	(6,067)
Other income & expenses	(1,201)	(100)	108,824	2,118	(484)
Gain (loss) before minority interest, income taxes and discontinued operations	(10,457)	(9,621)	94,285	(12,550)	(6,551)
Minority interest in (income) loss of consolidated subsidiaries	--	--	(3,551)	88	185
Benefit from (provision for) income taxes	2,279	3,326	(32,367)	15,332	--
Discontinued operations, net of tax	--	4,907	(2,004)	(1,819)	15,207
NET (LOSS) INCOME	$ (8,178)	$ (1,388)	$ 56,363	$ 1,051	$ 8,841
Per share financial data					
Operating revenues	$ 0.45	$ 0.10	$ 0.06	$ 0.04	$ 0.05

Loss from continuing operations		(0.43)	(0.41)	(0.71)	(0.88)	(0.38)
Other income & expenses		(0.06)	--	5.32	0.12	(0.03)
Gain (loss) befoe minority interest, income taxes and discontinued operations		(0.49)	(0.41)	4.61	(0.76)	(0.39)
Minority interest in income of consolidated subsidiaries		--	--	(0.17)	--	--
Benefit from (provision for) income taxes		0.11	0.14	(1.58)	0.81	--
Discontinued operations, net of tax		--	0.21	(0.10)	--	0.94
NET (LOSS) INCOME	$ (0.38)	$ (0.06)	$ 2.76	$ 0.05	$ 0.55

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

The Company's strategy is to enhance value for our shareholders through the development of a well-balanced portfolio of natural resource-based assets. These natural resource-based assets include (1) the acquisition and development of oil and gas properties, (2) exploration and development of geothermal properties, (3) energy related real estate developments and (4) a molybdenum property, The Company accomplishes these tasks by deploying its available cash reserves as well as joint venturing certain of its projects with industry participants. Each of these activities has different time horizons as well as levels of risk. Capitalized dollar amounts invested in each of these areas at December 31, 2009 and December 31, 2008 were as follows:

	(In thousands) December 31,	
	2009	2008
Evaluated Oil and Gas Properties	$ 24,595	$ 5,320
Unevaluated Oil and Gas Properties	$ 5,360	$ 2,968
Investment in Geothermal Properties	$ 2,958	$ 3,455
Commercial Real Estate	$ 24,600	$ 24,467
Undeveloped Mining Properties	$ 21,969	$ 23,950
	$ 79,482	$ 60,160

The 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's primary investment focus at December 31, 2009 remains in the acquisition and development of oil and gas properties. Oil and gas investments are made through industry partners who to date serve as the operator on the properties. As of December 31, 2009, the Company has invested with four industry partners and has drilled 14 gross wells. At December 31, 2009, nine of these wells were producing oil and gas, two were in the process of being completed and the remaining three wells were dry holes.

On August 24, 2009, the Company entered into an agreement with a wholly owned subsidiary of Brigham Exploration Company ("Brigham") to jointly explore for oil and gas in up to 19,200 acres in the Williston Basin of North Dakota. As of December 31, 2009, six wells had been drilled and completed and two additional wells were being drilled under this agreement for a total cost to the Company of $20.1 million for its participating interest. The Company and Brigham plan on drilling an additional 7 wells under this agreement during 2010.

The Company also has agreements with PetroQuest Energy, Inc. ("PetroQuest"), Yuma Exploration Company, Inc. ("Yuma") and Houston Energy L.P. ("Houston Energy"). The Company also plans on drilling wells with all these industry partners during 2010.

- The Company, through its investment of $4.3 million, owns 23.8% ownership of a geothermal limited partnership, Standard Steam Trust, LLC. ("SST"). The Company recorded an equity loss from SST during the year ended December 31, 2009 of $1.4 million for a net investment at December 31, 2009 of $3.0 million. The Company's investment in geothermal properties is not expected to return cash flows from operations. Rather, it is the Company's plan to work with other industry partners in the exploration and development of geothermal properties and when sufficient data has been gathered, sell them to utilities or large firms desiring the opportunity to construct and operate geothermal power plants. The investment in the geothermal industry allows the Company to participate in the development of power resources in an environmentally friendly industry. Returns on the geothermal investment are anticipated in the next two to five years.

- The Company continues to receive cash flows, revenues and net profits from its energy related multifamily housing development in north eastern Wyoming. The Company does not plan to build or acquire any additional multifamily housing projects.

- The Company's investment in the molybdenum property in Colorado, Mount Emmons, is a long term investment. The Company entered into an Option Agreement with Thompson Creek Metals Company USA ("TCM") on August 19, 2008. Under the agreement, TCM may acquire up to 75% ownership of the Mount Emmons property after expending $400 million.

The principal factors affecting the Company are the success of oil and gas exploration activities, commodity prices, the grade of mineral deposits, permitting and costs associated with exploration and development of the prospects.

Liquidity and Capital Resources

The Company maintained its strong liquidity position throughout the year ended December 31, 2009, notwithstanding its use of cash from entering into the oil and gas drilling agreement with Brigham and others; the retirement of the construction loan on the multifamily housing project; its investment in the geothermal industry as well as normal operating expenses. The Company also experienced $2.6 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, 2009 as compared to the year ended December 31, 2008:

	(In thousands) December 31, 2009	2008
Current ratio(1)	7.16 to 1	3.64 to 1
Working capital(2)	$ 53,428	$ 52,784
Total debt	$ 800	$ 1,875
Total cash and marketable securities less debt	$ 55,840	$ 41,474
Total stockholders' equity	$ 129,133	$ 111,833
Total liabilities to equity	.14 to 1	.27 to 1

(1) Current Assets divided by Current Liabilities
(2) Current Assets less Current Liabilities

The Company’s 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, 2009, the Company’s only debt is related to the acquisition of a property near the Mount Emmons molybdenum property. The Company may seek reserve based debt during 2010 to fund the acquisition of additional oil and gas properties and production. In addition, the Company has in place a $10 million line of credit available.

Components of the $644,000 increase in working capital for the years ended December 31, 2009 and 2008 were as follows:

	(In thousands)		
	December 31,		Increase
	2009	2008	(Decrease)
Cash and Cash Equivalents	$33,403	$8,434	$24,969
Marketable Securities			
U.S. Treasuries	22,059	51,152	(29,093)
Available for sale securities	1,178	576	602
Accounts Receivable			
Trade	3,882	600	3,282
Reimbursable project costs	2	442	(440)
Income taxes	353	5,896	(5,543)
Restricted investments	--	4,929	(4,929)
Other current assets	1,223	738	485
Current Assets	62,100	72,767	(10,667)
Accounts Payable	6,500	898	5,602
Accrued compensation	1,748	682	1,066
Short term construction debt	--	16,813	(16,813)
Current portion of long-term debt	200	875	(675)
Other current liabilities	224	715	(491)
Current Liabilities	8,672	19,983	(11,311)
Working Capital	$53,428	$52,784	$644

Major changes in working capital during the year ended December 31, 2009 were:

Current Assets

•

Cash increased by $25 million primarily as a result of the Company selling 5 million shares of its common stock in a public offering during the fourth quarter of 2009 for $24.3 million after offering costs. The Company used its cash as well as monetization of U.S. Treasuries in operations, oil and gas exploration and well completion costs, mineral property holding expenses, and investment in geothermal assets. Please see the discussion below regarding cash flows for the twelve months ended December 31, 2009.

- The increase in accounts receivable trade during the year ended December 31, 2009 corresponds with increased oil and gas sales in 2009 and is due to the lag time (30 to 60 days) between production and receipt of payment for production. The reduction of receivables of reimbursable project costs resulted from the collection of amounts due the Company at December 31, 2008 on the Mount Emmons molybdenum property.

- During 2009, the Company received $5.8 million from the Internal Revenue Service as a refund of income taxes paid in 2007. The loss incurred during the twelve months ended December 31, 2009 will be carried back against taxes paid in 2007. This carry back results in an additional amount receivable from the Internal Revenue Service of $353,000, for a net change of $5.5 million in the account receivable for income taxes.

- Restricted investments, cash held in an interest bearing account, decreased by $4.9 million due to the release of funds held in escrow as additional collateral for the construction loan of the multifamily housing project in Gillette, Wyoming. The construction loan of $16.8 million was repaid during the first quarter of 2009. The increase in other current assets at December 31, 2009 over the prior year relate primarily to increased pre paid insurance costs and increased inventories of oil and gas as a result of increased production during the year ended December 31, 2009.

Current Liabilities

- Accounts payable increased significantly as a result of drilling and completion costs associated with oil and gas activities in the Williston Basin with Brigham prior to December 31, 2009 which were not invoiced until January 2010.

- Accrued compensation expense increased as a result of the accrual of a bonus payable to all employees of the Company. The bonus is approximately $1.4 million. The accrued bonus at December 31, 2009 resulted from officers and employees accomplishing corporate and personal goals and financial results pursuant to a compensation plan, the Performance Compensation Plan, that was proposed by the Company's compensation committee and adopted by the full board of directors in April of 2009. The bonus will be paid in the first quarter of 2010. At December 31, 2008, there was a one-time bonus of $529,000 accrued for an officer. All other accrued compensation is the accrual of retirement benefits to two retired officers which will be paid through 2011.

- In an effort to maximize the return on cash reserves invested in U.S. Treasuries, the Company repaid a construction loan on its multifamily housing project in the amount of $16.8 million during the first quarter of 2009. At December 31, 2009, there was no debt against the housing project.

- At December 31, 2008, the Company had debt of $1,875,000 for the purchase of a property near the Mount Emmons molybdenum project. During the year ended December 31, 2009, the Company retired $1,075,000 of this debt leaving $200,000 as current debt and $600,000 as long term debt which will be retired at the rate of $200,000 per annum through December 31, 2013.

- The primary reduction in other current liabilities was the release of $478,000 of retainage due the contractor that construct the multifamily housing project in north east Wyoming.

Analysis of Cash Flows:

The following tables summarize the provision and use of cash in Operations, Investing Activities and Financing Activities for the years ended December 31, 2009, 2008 and 2007:

	(In thousands) December 31,		
	2009	2008	2007
Cash provided by (used in) Operations	$ 2,552	$ (6,536)	$ (29,411)
Cash provided by (used in) Investing Activities	$ 17,150	$ (70,557)	$ 86,820
Cash provided by Financing Activities	$ 5,267	$ 8,910	$ 255

Change in Cash and Cash Equivalents and U.S. Treasuries

	2009	2008	2007
Net Increase (Decrease) in cash and cash equivalents	$ 24,969	$ (63,857)	$ 55,318
Net (redemption)investment in U.S. Treasury investments	(29,093)	49,897	-
Net change in cash and U.S. Treasuries	$ (4,124)	$ (13,960)	$ 55,318

Investments of surplus cash in U.S. Treasuries have maturity dates in excess of 90 days and are therefore classified as Held to Maturity Marketable Securities for financial presentation purposes under Generally Accepted Accounting Practices ("GAAP") in the United States of America. Although they are classified in this manner they are used as needed to fund operations and capital projects, and accordingly are presented in the above table with cash and cash equivalents for clarity of the net change in ready liquid assets. A description of the provision of and use of cash in Operations, Investing Activities and Financing Activities for the year ended December 31, 2009 follows:

Operations:

Operations for the year ended December 31, 2009 resulted in a net after tax loss of $8.2 million. This loss included $9.9 million in non cash expenses related to depreciation, depletion, impairment on oil and gas properties, and equity loss from Standard Steam Trust, LLC. ("SST") – the Company's investment in the geothermal industry, and non cash compensation. The Company also received $5.8 million in a refund from the Internal Revenue Service.

For a complete discussion of the cash flows from Operations please refer to Results of Operations below.

Investing Activities:

Cash provided by Investing Activities:

- The vast majority of cash provided by Investing Activities is as a result of the redemption of U.S. Treasuries in the amount of $29.3 million.

- TCM paid the first option payment of $1.0 million in January 2009 and prepaid the second option payment of $1.0 million in December 2009. The second option payment was not due until January 2010.

- Net proceeds from the release of restricted investments of $4.6 million is the release of cash, held as additional collateral, by the construction loan lender, when the construction loan was repaid during the first quarter of 2009.

Cash consumed in Investing Activities:

- The Company invested an additional $877,000 in SST during the year ended December 31, 2009 to fund SST's operating overhead and the acquisition of additional prospective geothermal properties.
- The Company invested $17.5 million in oil and gas properties.
- The Company invested $410,000 in property and equipment, $254,000 for the improvement of certain equipment within the water treatment plant at the Mount Emmons water treatment plant, $133,000 in improvements at the Company's multifamily housing project and $23,000 in the acquisition of office equipment.

Financing Activities:

Cash provided by Financing Activities:

- The Company sold five million shares of its common stock in a public offering during the fourth quarter of 2009. The shares were priced at $5.25 per share for which the Company received $24.3 million net, after offering expenses plus an additional $238,000 for the exercise of employee options and warrants to third party consultants.

Cash consumed in Financing Activities:

- The Company retired $17.9 million in long term debt. The retired debt consisted of $16.8 million due under a construction loan for the Company's multifamily housing project and $1.1 million due under a note for the purchase of a 160 acre parcel of property purchased in the vicinity of the Mount Emmons molybdenum project.
- The Company completed its $8.0 million stock buyback program by purchasing 706,071 shares of its common stock for $1.4 million, or an average cost per share of $1.98 per share.

Capital Resources

Oil and Gas Production

The Company's current sources of cash are expected to be provided by successful oil and gas wells. The ultimate amount of cash resources derived from the production of oil and gas will be determined by production volumes, the price of oil and gas, exploration and production costs. The Company plans to continue its exploration for and development of oil and gas properties and may also acquire existing production.

The following table is a summary of the Company's estimated reserves as of December 31, 2009:

Estimated net proved reserves:	Bakken	Gulf Coast	Total
Producing:			
Oil (bbls)	749,213	36,884	786,097
Gas (Mcf)	569,296	908,000	1,477,296
NGL (bbls)	--	24,031	24,031
Non-producing:			
Oil (bbls)	--	25,692	25,692
Gas (Mcf)	--	24,000	24,000
NGL (bbls)	--	--	--
Total (BOE)	844,096	241,940	1,086,036
Future net income before income taxes	$31,047,000	$5,848,000	$36,895,000
PV10	$20,768,000	$4,992,000	$25,760,000

Estimated proved reserves (on a BOE basis) at December 31, 2009 increased by 889,738 BOE or approximately 453% over estimated proved reserves at December 31, 2008. Most of the increase is related to the six proved Bakken wells at December 31, 2009.

The reserve estimates are calculated by independent engineering firms in accordance with SEC rules. Estimated future net cash flows before income taxes are discounted at 10%. This value is not intended to represent the current market value of the reserves. Reserve estimates are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, oil and gas prices, and other factors.

Estimates of reserve volumes and future net cash flows are based on the average of first day of month prices during the year ended December 31, 2009 ($61.18 per barrel of oil and $3.866 per MMbtu of gas). Future estimated production taxes and ad valorem taxes, capital costs and operating costs are deducted from estimated future cash flows, and the result is discounted at an annual rate of 10% to determine "present value" ("PV10").

PV10 is widely used in the oil and gas industry, and is followed by institutional investors and professional analysts, to compare companies. However, the PV10 data is not an alternative to the standardized measure of discounted future net cash flows calculated under GAAP and in accordance with ASC 932-235-55, which includes the effects of income taxes. The following table provides a reconciliation of Estimated Future Net Revenues Discounted at 10% to the Standardized Measure of Discounted Future Net Cash Flows as shown in Note F to the Company's Consolidated Financial Statements.

	Year Ended December 31, 2009
Estimated future net revenues discounted at 10%	$ 25,760,000
Future income tax expense (discounted)	(5,776,000)

Standardized measure of discounted future net cash flows	$ 19,984,000

Cash on Hand

At December 31, 2009, the Company had $33.4 million in cash and cash equivalents and $22.1 million in U.S. Treasuries. The Company has invested its cash in interest bearing accounts, with the majority invested in U.S. Government Treasuries. During the past two years, this investment policy has insured the preservation of principal and yielded a return. Additionally, the investment of the Company’s surplus cash in U.S. Treasuries has insured that the Company would not become an inadvertent investment company.

Commercial Bank

Line of Credit – During January 2010, the Company entered into a $10.0 million line of credit with a commercial bank (an increase from the $5.0 million line of credit at the same bank in 2009). No borrowings have been made under this line of credit as of the date of this report. The line of credit has a variable interest rate which is tied to a national market rate with a minimum interest rate of 5.5%. The line of credit is available until January 31, 2011 at which time it may be renewed depending on the financial strength and needs of the Company. The credit line is secured by the Company’s multifamily housing project in north east Wyoming and a corporate aircraft.

Equity Market

The Company filed a registration statement with the Securities and Exchange Commission on October 20, 2009 which became effective on November 6, 2009. The registration statement provides for the sale of $100 million of the Company’s common stock. During the fourth quarter of 2009, the Company sold 5 million shares of its common stock for $5.25 per share or $26.3 million, $24.3 net of offering costs. Additional capital may be raised under the registration statement to fund future oil and gas acquisitions and development drilling.

Real Estate

The Company owns a 216 unit multifamily housing property in Gillette, Wyoming, known as Remington Village. The property averaged an occupancy rate of 88% during 2009 and was 80% occupied as of December 31, 2009. Occupancy is dependent on coal mining operations, oil and gas exploration and construction of a power generating plant in the area. As with all sectors of the energy industry, there was a slow down during 2009 in the Gillette, Wyoming area. The property generated positive cash flow of $1.7 million during 2009 and is projected to remain in that range of cash flow during 2010. To reach these levels occupancy rates will have to average 88% and costs and expenses remain similar to those experienced in 2009.

Although the property is pledged as collateral for the Company’s $10 million line of credit, there is no debt against the property. The Company may seek long term financing on the property during 2010 to further its oil and gas exploration and development projects. The Company plans on holding the property until the local real estate market improves, at which time the property may be sold. The company has $24.5 million invested in the property.

Mount Emmons Molybdenum Property and Thompson Creek Metals Company, USA

The Company entered into and agreement with TCM for the permitting and development of the Mount Emmons molybdenum property, near Crested Butte, Colorado. Under the terms of the agreement TCM pays all costs related to activities on the project with the exception of the water treatment plant which are currently paid 100% by the Company. TCM may earn up to a 75% interest in the property after it spends $400 million. At such time as TCM has acquired its desired level of ownership the Company and TCM will fund all costs in proportion to their ownership.

TCM is obligated to pay the Company six annual option payments in the amount of $1.0 million each due in January each year through 2014. TCM has paid two of these payments as of December 31, 2009, one of which was prepaid in December 2009 for the January 2010 option payment.

Once permitted and placed into production, Mount Emmons is expected to provide the Company with long term capital resources. Historical records filed by predecessor owners of the Mount Emmons molybdenum property with the Bureau of Land Management (BLM) in the 1990's for the application of patented mineral claims, referenced identification of mineral resources of approximately 220 million tons of 0.366% molybdic disulfide (MoS2) mineralization. A high grade section of the mineralization containing roughly 23 million tons at a grade of 0.689% MoS2 was also reported. No assurance can be given that these quantities of MoS2 exist or that the Company and TCM will be successful in permitting the property.

Future Receipts of Royalties and Contractual Commitments from Uranium Properties

The Company retained a 4% Net Profits Royalty on a portion of the Green Mountain uranium property in Wyoming which is owned and operated by Rio Tinto, Inc. No assurance can be given as to when or if the property will be placed into production. Any royalty due will be based on the market price of uranium concentrates and the cost of producing those concentrates.

Pursuant to the terms of the 2007 sale of the Company's uranium properties, the Company is entitled to receive $20 million when commercial production begins at the Utah uranium mill which the Company sold; $7.5 million when the first delivery of ore to any commercial mill, after commercial production commences, from any of the uranium properties the Company sold; and a production royalty of up to $12.5 million. No assurance can be given as to if or when these events and payments will occur.

Capital Requirements

The direct capital requirements of the Company during 2010 are the funding of the drilling and completion of nine additional wells with Brigham in the Bakken formation, additional oil and gas exploration and development projects, acquisition of prospective oil and gas properties and or existing production, operating and capital improvement costs of the water treatment plant at the Mount Emmons molybdenum project, operations at Remington Village, possible additional funding of geothermal operations and general and administrative costs.

Oil and Gas Exploration and Development

The total amount of capital expenditures that the Company has budgeted for the exploration and development of oil and gas resources during 2010 is $41.5 million. These costs are not firm commitments. Provided that the Company has the capital available, it plans on spending these funds to develop additional reserves to increase revenues and cash flows. The following is a breakdown of the budgeted amounts by area.

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Bakken – Williston Basin North Dakota

Under its agreement with Brigham, the Company is committed to drill and complete an additional nine wells in the Williston Basin during 2010. The Company has budgeted $18.6 million for these activities. The actual amount expended on the nine wells will vary from the budgeted amount as a result of larger or smaller ownership interests of Brigham. Other factors which can cause actual to vary from budgeted amounts are drilling conditions, problems encountered on site and weather. The wells to be drilled in 2010 will be approximately 10,000 feet in depth with 10,000 foot laterals to be completed with 28 to 32 frac stages. The first six wells drilled with Brigham have cost approximately $6.3 million each on an 8/8th basis.

By electing to participate in all of the initial wells available to us, we have earned the rights to drill up to 30 total wells in the Bakken formation and an additional 30 wells in the Three Forks formation, for a total of 60 wells, based on current spacing rules in North Dakota. If the spacing is ultimately increased to three wells per 1,280 acre spacing unit, the potential number of drilling locations could increase to 90. Working interests earned will vary according to Brigham's initial working interest, after-payout provisions and the provisions governing each stage of the program. At our current and projected drilling rates, we expect that it will take four to six years to drill all of the wells in these units.

Gulf Coast

The Company has budgeted $4.4 million to drill up to four wells with PetroQuest in the Gulf coast area in 2010. Weather and down hole problems can cause wells in this area to cost more than anticipated. The Company has drilled one successful gas well and one dry hole with PetroQuest.

The Company has budgeted $1.5 million to drill up to three shallow inland oil and gas wells with Houston Energy. These wells have a lower risk of weather challenges due to the fact that they are inland.

The Company has budgeted $1.7 million to drill six wells and maintain leases as well as complete interpretation of seismic data with Yuma in 2010.

Other

The Company has budgeted $240,000 for the maintenance of leases during 2010 as well as $15.0 million for the acquisition of either prospective oil and gas properties or existing production.

Mount Emmons Molybdenum Property

Under the terms of its agreement with TCM, the Company is responsible for all costs associated with operating the water treatment plant at the Mount Emmons molybdenum property. Annual operating costs during 2010 are projected to be approximately $1.7 million. Additionally, the Company has budgeted $1.6 million for capital improvements in the plant which are expected to improve its efficiency.

The Company and TCM purchased a 160 acre parcel of property near the Mount Emmons property. Under the terms of the purchase agreement the Company is obligated to make annual payments to the prior owner in the amount of $200,000 beginning in January 2010 through January 2014 with 6% interest per annum on the unpaid balance. In addition to the retirement of the debt, the Company will be responsible for one half of the holding and operating costs of the acreage which are expected to be minimal.

Through December 31, 2009, TCM has expended $7.6 million on the property which includes $2.5 million in option payments to the Company. Although TCM is contractually obligated to spend $5.0 million during 2010 it has budgeted $8.4 million for the project in 2010. Both the contractual amount as well as budgeted amount include the $1.0 million option payment to the Company which was pre-paid by TCM in December 2009. As per the terms of the agreement with TCM, the Company will not be required to fund any of the proposed work to be performed on the property during 2010 unless TCM terminates the agreement. TCM, as project manager, is preparing and evaluating engineering and environmental reports and studies to prepare a Plan of Operations, and anticipates submitting it to the U.S. Forest Service (“USFS”) in 2010. All the costs of developing and submitting this plan will be paid for by TCM as per the agreement.

Real Estate

Cash operating expenses at Remington Village are projected to be $1.1 million for 2010. The Company does not anticipate any major capital expenditures on the property. Remington Village is pledged as collateral for a $10.0 million line of credit with a commercial bank. At the date of this report there was no debt against Remington Village. The Company may seek long term financing of the property during 2010 to provide capital for the exploration and development or acquisition of oil and gas properties and or production. At December 31, 2009, the Company had invested $24.5 million in the property.

Geothermal and Alternative Energy Projects

The Company invested $4.3 million in a geothermal company, Standard Steam Trust, LLC, (“SST”) as of December 31, 2009. This investment was reduced by an equity loss of $1.4 million leaving a net investment at December 31, 2009 of $3.0 million. As a result of not funding a cash call in December of 2009, the Company’s ownership interest of SST was reduced from 25% to 23.8%. SST plans on continuing its temperature gradient drilling and the acquisition of additional prospective geothermal properties during 2010. The Company has not budgeted any capital resources for further investment in SST during 2010 but may elect to participate in cash calls during the year. The Company is not obligated to fund cash calls and will suffer further dilution if it does not fund.

Reclamation Costs

The Company has two reclamation obligations:

- Oil and Gas

Bakken – The Company’s reclamation obligation on the six wells drilled in the Williston Basin as of December 31, 2009 is $37,000.

Gulf Coast – The Company’s reclamation on all Gulf Coast wells drilled as of December 31, 2009 is $45,800.

No reclamation is expected to be performed on the existing wells at December 31, 2009 during the year ended December 31, 2010. Reclamation will only begin after the wells no longer produce oil or gas in economic quantities. The earliest projected reclamation will begin in 2013 in the Gulf Coast.

- Mount Emmons molybdenum property –

The asset retirement obligation for the Mount Emmons molybdenum property at December 31, 2009 is $128,500. As the Mount Emmons project is developed, the reclamation liability is expected to increase. It is not anticipated that this reclamation work will occur in the near term. The Company's objective, upon closure of the proposed mine at the Mount Emmons property, is to eliminate long-term liabilities associated with the property.

Results of Operations

Year Ended December 31, 2009 Compared with the Year ended December 31, 2008

The Company recorded a net loss after taxes of $8.2 million, or $0.38 per share, for the year ended December 31, 2009 as compared to a net loss after taxes of $1.4 million, or $0.06 per share, during the year ended December 31, 2008. The net loss for the year ended December 31, 2008 included a gain of $4.9 million, or $0.21 per share, from discontinued operations related to the sale of a portion of the Company's investment in Sutter Mining Company, Inc. Non cash expenses during the years ended December 31, 2009 and 2008 are as follows:

	(In thousands) Year ended December 31,	
	2009	2008
Depreciation, depletion and amortization	$ 5,066	$ 1,426
Impairment of oil and gas properties	1,468	--
Impairment of marketable securities	--	1,023
Equity loss from SST	1,374	--
Non cash compensation	1,935	2,536
Non cash services	65	46
Totals	$ 9,908	$ 5,031

Depreciation, amortization and depletion expense increased $3.6 million during the year ended December 31, 2009 over the prior year due primarily to the increased depletion on wells drilled in the Williston Basin and the a full years depreciation of the Company's multifamily housing complex. Non-cash compensation decreased $601,000 during the year ended December 31, 2009 from those recorded during the same period of 2008 as a result of lower expenses related to the amortization of stock options and lower market prices for the Company's common stock related to equity compensation.

The Company recognized $9.6 million in revenues during the year ended December 31, 2009 as compared to revenues of $2.3 million during the prior year. Tabular representation of the increases in revenues as well as the loss from operations for the four quarters of 2009 and the years ended December 31, 2009 and 2008 is as follows:

(In thousands)	2009 Quarters Ended				Year Ended December 31,	
	March 31,	June 30,	September 30,	December 31,	2009	2008
Revenues	$ 1,413	$ 1,394	$ 1,284	$ 5,536	$ 9,627	$ 2,287
Operating Expenses	2,683	2,603	2,322	4,741	12,349	$ 10,382
Depreciation, Depletion and Amortization	1,089	981	848	2,148	5,066	1,426
Impairment	1,063		405		1,468	-
	4,835	3,584	3,575	6,889	18,883	11,808
Operating Loss	(3,422)	(2,190)	(2,291)	(1,353)	(9,256)	(9,521)

Fourth quarter revenues are on average four times greater than the first three quarters of 2009. The increase is as a result of the Company's drilling activity in the Williston Basin wells with Brigham. The fourth quarter revenues are reflective of only six wells drilled and completed during the fourth quarter of 2009 with production occurring primarily during the months of November and December. Revenues during the fourth quarter increased by a factor of four times while expenses roughly doubled of the previous quarters. The increased expenses are a result of the increased depletion recognized on the increased oil production during the quarter. Also included in the increased operating expenses is a $1.4 million bonus accrual pursuant to the Company's adopted performance compensation plan. The bonus will not be paid until the first quarter of 2010. During the year ended December 31, 2009, the Company recorded an impairment of $1.5 million on its oil and gas operations due to depressed oil and gas prices during the first and third quarters of 2009 and only one producing well to spread the entire exploration cost over. As a result of increased oil and gas prices during the fourth quarter of 2009 and additional production to amortize the full cost pool over, no additional impairment was required during 2009.

The oil production from the Williston Basin has not only increased revenue trends but has also cut the operating loss by half on a quarterly basis. As additional wells are drilled and completed during 2010 it is believed that this trend will continue. The Company has experienced a very high rate of completion in the Williston Basin with good initial production flows. Future wells may not perform as well. The multi stage frac completion techniques used by the Company and Brigham are relatively new which makes long term production projections uncertain. The Company relies on professional third party reserve engineers to calculate decline curves.

Oil and gas operations produced a net operating gain during the year ended December 31, 2009 as compared to a loss from oil and gas operations during the year ended December 31, 2008. The following table details the results of operations from the oil and gas sector on a quarterly basis for 2009 and an annual basis for the years ended December 31, 2009 and 2008:

(In thousands)						
	2009 Quarters Ended				Year ended December 31,	
Oil & Gas	March 31,	June 30,	September 30,	December 31,	2009	2008
Revenues	$ 674	$ 645	$ 593	$ 4,932	$ 6,844	$ 571
Operating expenses	$ 99	$ 71	$ (29)	$ 207	$ 348	$ 62
Depreciation, depletion and amortization	713	607	475	1,776	3,571	382
Impairment	1,063	--	405	--	1,468	--
	$ 1,875	$ 678	$ 851	$ 1,983	$ 5,387	$ 444
Operating (loss) gain	$ (1,201)	$ (33)	$ (258)	$ 2,949	$ 1,457	$ 127

Production from the Williston Basin during the fourth quarter of 2009 increased revenues from oil and gas operations by 7.7 times over the prior three quarters of 2009 and 12 times over the revenues from oil and gas production during the twelve months ended December 31, 2008. The operating gain from oil and gas operations during the fourth quarter of 2009 was $2.9 million in comparison to an annual gain from oil and gas operations of $1.5 million. During the first three quarters of 2009, the Company recorded an impairment of $1.5 million.

The following table summarizes production volumes, average sales prices and operating revenues for the years ended December 31, 2009 and 2008:

	Year ending December 31,		2009 Period Compared to 2008 Period	
	2009	2008	Increase (Decrease)	% Increase (Decrease)
Production volumes				
Oil and condensate (Bbls)	80,461	2,330	78,131	3353 %
Natural gas (Mcf)	487,978	73,635	414,343	563 %
Average sales prices				
Oil and condensate (per Bbl)	$ 60.01	$ 36.78	$ 23.23	63 %
Natural gas (per Mcf)	4.13	6.59	(2.46)	-37 %
Operating revenues (in thousands)				
Oil and condensate	$ 4,829	$ 86	$ 4,743	5534 %
Natural gas	2,015	485	1,530	315 %
Total operating revenue	6,844	571	6,273	1099 %

Lease operating expense		(348	)	(62	)	(286	)	460 %
DD&A		(3,571	)	(382	)	(3,189	)	835 %
Impairment		(1,468	)	--		(1,468	)	100 %
Gain	$	1,457		$ 127		$ 1,330		1049 %

The Company plans to drill and complete an additional nine wells in the Williston Basin during 2010. Factors that could affect the income from operations in 2010 on wells to be drilled are:

- Lower working interests in the wells due to lower ownership interest in the leases held by Brigham
- Brigham has elected to participate at 50% which will reduce both the cost to the Company as well as the revenues if the wells are successful
- Lower market prices for oil and gas during 2010
- Higher drilling and operating expenses
- Steeper decline rates than currently anticipated
- Mechanical and geological problems with the wells

The Company's other revenue producing sector is commercial real estate. A breakdown of the income from operations from commercial real estate is contained in the following table:

(In thousands)

	2009 Quarters Ended				Year Ended December 31,	
Real Estate	March 31,	June 30,	September 30,	December 31,	2009	2008
Revenues	$ 734	$ 745	$ 686	$ 603	$ 2,768	$ 1,633
Operating Expenses	280	237	245	297	1,059	648
Interest Expense	19	-	-	-	19	417
Depreciation, Depletion and Amortization	232	261	262	290	1,045	517
	531	498	507	587	2,123	1,582
Operating Gain	$ 203	$ 247	$ 179	$ 16	$ 645	$ 51

Although revenues increased $1.1 million during the year ended December 31, 2009 over the prior year, the Company experienced a decline in quarterly revenues throughout the year. The decline is as a result of lower occupancy rates at Remington Village. Expenses increased during the fourth quarter as a result of a bad debt write off of $64,000. As a result of a full year of operations, revenues increased as well as the operating gain from $51,000 in 2008 to $645,000 during the year ended December 31, 2009. Commercial real estate generated positive cash flow of $1.7 million during the year ended December 31, 2009 and $1.1 million during the year ended December 31, 2008. Interest expense was reduced from $417,000 during 2008 to $19,000 during 2009 as a result of the repayment of the construction loan utilized to build the property. The loan was retired in January of 2009 and no debt existed against the property as of December 31, 2009.

Mount Emmons Molybdenum Property

When the Company entered into its agreement with TCM, it agreed to pay all costs associated with the water treatment plant at the Mount Emmons molybdenum property and thereby recorded $1.6 million in costs and expenses for that facility and $323,000 in holding costs of the Mt. Emmons molybdenum property during the year ended December 31, 2009. During the year ended December 31, 2008, the Company expended $1.5 million in operating costs related to the water treatment plant and $834,000 in holding costs related to the Mt. Emmons molybdenum property.

General Administrative

General and administrative expenses increased by $1.5 million during the year ended December 31, 2009 over those experienced at during the year ended December 31, 2008. The increase is as a result of the accrual of a yearend bonus to all employees of the Company as a result of meeting corporate and personal goals, meeting annual budget goals, increased share price and cash flow from operations. Under a Performance Compensation Plan ("PCP") adopted by the board of directors, employees can earn from 33% to 100% of their base compensation as bonuses if the terms of the PCP are met. No employees earned 100% of their base compensation or the allowable amount under the PCP during 2009 as certain financial measurements were not met. The PCP was proposed by the Company's Compensation Committee and adopted by the full Board in April 2009. Details of the PCP are disclosed in their entirety in the Company's annual proxy statement for the annual meeting held in June of 2009. The bonus for 2009 performance will be paid during the first quarter of 2010.

Other income and expenses – The Company recorded an equity loss of $1.4 million from its investment in SST during the year ended December 31, 2009 with no similar losses reported during the prior year. Equity losses from the Company's investment in SST are expected to continue until such time as SST properties are sold, equity losses reduce the Company's investment to zero or the Company sells its investment. Interest income decreased from $1.4 million during the year ended December 31, 2008 to $314,000 during the year ended December 31, 2009. The decrease is a result of lower amounts of cash invested in interest bearing instruments and lower interest paid on those investments. Interest expense during the year ended December 31, 2009 was related primarily to the construction loan for Remington Village, $19,000, and the financing of a property purchased with TCM near the Mount Emmons property, $60,000. Interest expense during 2008 related primarily to the construction loan for Remington Village which was fully repaid in January 2009.

During the year ended December 31, 2008, the Company recorded a net gain on the sale of its controlling interest in Sutter Gold Mining, Inc of $4.9 million. No similar activities occurred during the year ended December 31, 2009.

The Company therefore recorded a net loss after taxes of $8.2 million, or $0.38 per share, during the year ended December 31, 2009 as compared to a net loss after taxes of $1.4 million, or $.06 per share, during year ended December 31, 2008.

Year Ended December 31, 2008 Compared with the Year Ended December 31, 2007

During the twelve months ended December 31, 2008, the Company recorded a loss of $1.4 million as compared to a gain of $56.4 million during 2007. The decrease in net earnings for 2008 as compared to 2007 is primarily due to a gain on the sale of uranium assets during 2007 in the amount of $111.7 million. Other components in the net change to the results of operations were (a) increased Revenues during 2008 from real estate rentals and the sale of oil and gas, (b) decreased Operating Costs and Expenses during 2008, (c) reduced Other Income and Expenses, (d) the elimination of minority interest in the gain of consolidated subsidiaries, (e) increased gain from discontinued operations during 2008 as a result of the sale of the Company's controlling interest in Sutter Gold Mining, Inc. ("SGMI") and (f) changes in the provision for and benefit from Income Taxes.

Operating Revenues:

Rental revenues of $1.5 million were received from Remington Village, during 2008. There were no revenues from Remington Village in 2007 as there were no units available for rent during the early construction period. Other real estate revenues decreased $832,000 during 2008 from those recorded during 2007. The decrease was as a result of the Company selling lots at its southern Utah real estate property during 2007 while no similar sales occurred during 2008 as the entire property was ultimately sold during 2007. The Company recorded its first revenues from its successful well drilled in the Gulf Coast during 2008 of $571,000. There was no oil or gas production during 2007. The reduction of $157,000 in management fee and other revenues during the twelve months ended December 31, 2008 is as a result of no management fees being charged on the uranium properties during 2008 as all the uranium properties were sold in 2007. Lower management fees were charged against Mount Emmons as the Company was the operator from March 31, 2008 through August 19, 2008 during which time there were no management fees charged. The Company charged management fees for services it provided under the contract with Kobex to the Mount Emmons property during the twelve months ended December 31, 2007.

Operating revenues therefore increased by $1.1 million for the year ended December 31, 2008 as compared to the year ended December 31, 2007.

Operating Costs and Expenses:

Operating Costs and Expenses decreased by $3.9 million for the year ended December 31, 2008 as compared to the year ended December 31, 2007. Operating Costs and Expenses related to other real estate and general and administrative costs were reduced while expenses associated with the Remington Village project, oil and gas production and mineral holding costs increased.

Operating costs for Remington Village during 2008 were $839,000. These costs consist of contract property management services, maintenance, insurance and general administration costs and $469,000 of depreciation. There were no operating costs relating to Remington Village during 2007.

There were no costs and expenses for the production of oil and gas during 2007. During 2008, the Company recorded expenses of $444,000 for its portion of the operating costs and expensed for the producing well in the Gulf Coast.

Mineral holding and water treatment costs increased by $1.2 million during 2008 over the same costs and expenses during 2007. The increases were for the cost of operating and maintaining the water treatment plant at Mount Emmons, of $1.5 million and $834,000 for costs and expenses incurred by the Company for engineering studies during the time it served as manager of the property. This increase is as a result of the withdrawal of Kobex from the Mount Emmons molybdenum property on March 31, 2008. Subsequent to March 31, 2008 the Company paid the holding costs related to the Mount Emmons property while Kobex paid these costs during 2007. After August 19, 2008, the Company continued to pay all costs associated with the water treatment plant and TCM paid all other costs associated with the property.

General and administrative costs and expenses were reduced primarily as a result of a bonus which was paid to all employees and directors of the Company 2007 at the closing of the sale of the Company's uranium assets to Uranium One and the payment of an early retirement severance package for one of the Company's officers. Although there was no similar bonus paid during 2008, the Company did pay one half of a $500,000 bonus to one of its officers which was approved on March 7, 2008. The approved bonus to the officer was for services rendered over many years, was comparable to a similar bonus paid two former officers for similar services, is net of taxes and is payable in eight equal quarterly payments beginning on March 31, 2008 and ending December 31, 2009.

Other Income and Expenses:

During 2007, there were transactions relating to gains and losses from the sale of uranium assets and marketable securities, while there were no similar transactions during 2008. The combined income recognized from the sale of the uranium assets and sale of securities during 2007 compared to no similar activities during 2008 accounted for the majority of the decrease of other income and expenses of $108.9 million.

During 2008, the Company recorded a net loss of $17,000 on the sale of its used corporate aircraft and other miscellaneous equipment due to some repairs that had to be made to the aircraft prior to the sale. The Company netted $1.1 million from the sale of the aircraft when it was sold. The loss recorded during 2008 from the sale of assets is compared to a gain of $2.3 million during 2007. The gain recorded in 2007 was as a result of the sale of a townsite in southern Utah and the receipt of payments due under the Mount Emmons agreement with Kobex as well as an agreement related to the uranium properties which were sold to Uranium One.

Interest Income – The Company recognized $1.4 million in interest income during 2008, which is $1.4 million less than the interest income received during 2007. The decrease during 2008 is as a result of lower levels of cash being invested at significantly lower interest rates. At December 31, 2008, the Company was earning between .22% and 1.91% on its U.S. Treasury Bills. This low interest rate is reflective of the condition of global economics. The Company continues to seek the deployment of surplus funds into investments and operations which will yield a higher return.

Interest Expense during 2008 increased $426,000 over the interest expense recorded during 2007 to $486,000. The increase is as a result of completion of Remington Village. As each of the nine buildings were completed, the Company no longer capitalized construction loan interest on that building but rather expensed it. The interest thus expensed on the construction loan resulted in the increased interest expense.

During 2007, the Company acquired the minority interest shares of Crested Corp. As a result of that acquisition and the sale of SGMI, there are no minority interest in gains and losses of consolidated subsidiaries at December 31, 2008. The Company reported a minority interest in the gain of consolidated subsidiaries for the year ended December 31, 2007 of $3.6 million. The minority interest gain in consolidated subsidiaries recorded during the year ended December, 2007 was primarily the minority interest gain of $3.6 million of Crested. On a consolidated basis, all previous minority interest losses of Crested that were absorbed by the Company through consolidation have been fully reinstated through December 31, 2007.

During 2008, the Company sold its controlling interest in SGMI. The Company recognized a gain of $5.4 million on the sale of the shares of SGMI and a loss of $501,000 from the discontinued operations of SGMI. This results in a net gain on the sale of the SGMI shares of $4.9 million. As a result of the Company's controlling interest in SGMI, the Company has shown the loss from SGMI which was previously consolidated as a loss from discontinued operations of $2,003,600 at December 31, 2007.

Due to the loss recorded during the year ended December 31, 2008, the Company recorded a net benefit from income taxes during the year then ended of $3.3 million. During the year ended December 31, 2007 the Company recorded a provision for income taxes of $32.4 million.

As a result of the above described changes in revenues, costs and expenses, the Company recorded a loss of $1.4 million during the year ended December 31, 2008, or a loss of $0.06 per share as compared to a gain of $56.4 million or $2.75 earnings per share basic and $2.54 per share diluted during the year ended December 31, 2007.

Critical Accounting Policies

Mineral Properties - The Company capitalizes all costs incidental to the acquisition of mineral properties. Mineral exploration costs are expensed as incurred. When exploration work indicates that a mineral property can be economically developed as a result of establishing proved and probable reserves, costs for the development of the mineral property as well as capital purchases and capital construction are capitalized and amortized using units of production over the estimated recoverable proved and probable reserves. Costs and expenses related to general corporate overhead are expensed as incurred. All capitalized costs are charged to operations if the Company subsequently determines that the property is not economical due to permanent decreases in market prices of commodities, excessive production costs or depletion of the mineral resource.

Mineral properties at December 31, 2009 and December 31, 2008 reflect capitalized costs associated with the Company's Mount Emmons molybdenum property near Crested Butte, Colorado. The Company has entered into an agreement with TCM to develop this property. TCM may earn up to a 75% interest in the project for the investment of $400 million. The Company received the first two of six anticipated annual payments in the amount of $1.0 million during 2009. These payments were applied as a reduction of the Company's investment in the Mount Emmons property.

The Company reviews its investment in the Mount Emmons property annually to determine if an impairment has occurred to the carrying value of the property. As a result of the market price for Molybdenum Oxide increasing from $10.00 per pound at December 31, 2008 to $11.50 per pound at December 31, 2009 and the reduction of the book value of Mount Emmons by $2.0 million as a result of TCM's option payments, as well as the continued support of TCM in the form of a $8.4 million budget for 2010 work on the property, the Company has determined that no impairment is needed to the book value of the property.

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Oil and Gas Properties - The Company follows the full cost method in accounting for its oil and gas properties. 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 average prices per barrel of oil and per MMbtu of natural gas at the first of each month in the 12-month period prior to the end of the reporting period and costs, adjusted for contract provisions, financial derivatives that hedge the Company's oil and gas revenue and asset retirement obligations, (ii) the cost of properties not being amortized, (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 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.

Ceiling Test - The Company performs a quarterly ceiling test for each of its oil and gas cost centers, which in 2009 and 2008, there was only one. The ceiling test incorporates assumptions regarding pricing and discount rates over which management has no influence in the determination of present value. In arriving at the ceiling test for the year ended December 31, 2009, the Company used $61.18 per barrel for oil and $3.866 per MMbtu for natural gas to compute the future cash flows of the Company's producing property. The discount factor used was 10%.

At December 31, 2009, the ceiling was in excess of the net capitalized costs as adjusted for related deferred income taxes and no impairment beyond the $1.5 million impairment taken in the first three quarters of 2009 was required. Furthermore, as of year-end there were no unproved properties that were considered to be impaired and reclassified to properties being amortized. Management will continue to review its unproved properties based on market conditions and other changes and if appropriate unproved property amounts may be reclassified to the amortized base of properties within the full cost pool.

Proved Reserves – Our estimates of proved reserves are based on quantities of oil and gas reserves which current engineering data indicates are recoverable from known reservoirs under existing economic and operating conditions. Estimates of proved reserves are key elements in determining our depletion expense and our full cost ceiling limitation. Estimates of proved reserves are inherently imprecise because of uncertainties in projecting rates of production and timing of developmental expenditures, interpretations of geological, geophysical, engineering and production data and the quality and quantity of available data. Changing economic conditions also may affect our estimates of proved reserves due to changes in developmental costs and changes in commodity prices that may impact reservoir economics. We utilize independent reserve engineers to estimate our proved reserves annually.

On December 29, 2008, the SEC issued a revision to Staff Accounting Bulletin 113 (“SAB 113”) which established guidelines related to modernizing accounting and disclosure requirements for oil and natural gas companies. The revised disclosure requirements include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. The revised rules also allow companies the option to disclose probable and possible reserves in addition to the existing requirement to disclose proved reserves. The revised disclosure requirements also require companies to report the independence and qualifications of third party preparers of reserves and file reports when a third party is relied upon to prepare reserves estimates. A significant change to the rules involves the pricing at which reserves are measured. The revised rules utilize a 12-month average price using first of the month pricing during the 12-month period prior to the ending date of the balance sheet to report oil and natural gas reserves rather than year-end prices. In addition, the 12-month average will also be used to measure ceiling test impairments and to compute depreciation, depletion and amortization. The revised rules are effective for reserve estimation at December 31, 2009 with first reporting for calendar year companies in their 2009 annual reports.

Use of Estimates - The preparation of financial statements in conformity with generally accepted accounting principles in the USA requires management to make estimates and assumptions. These estimates and assumptions affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates include oil and gas reserves used for depletion and impairment considerations and the cost of future asset retirement obligations. Due to inherent uncertainties, including the future prices of oil and gas, these estimates could change in the near term and such changes could be material.

Asset Retirement Obligations - The Company records the fair value of the reclamation liability on its oil and gas and non operating mining properties as of the date that the liability is incurred. The Company reviews the liability each quarter and determines if a change in estimate is required as well as accretes the liability on a quarterly basis for the future liability. Final determinations are made during the fourth quarter of each year. The Company deducts any actual funds expended for reclamation during the quarter in which it occurs.

Revenue Recognition - The Company records oil and natural gas revenue under the sales method of accounting. Under the sales method, the Company recognizes revenues based on the amount of oil or natural gas sold to purchasers, which may differ from the amounts to which the Company is entitled based on its interest in the properties. Gas balancing obligations as of December 31, 2009 were not significant. Revenues from real estate operations are reported on a gross revenue basis and are recorded at the time the service is provided.

Stock Based Compensation - The Company measures the cost of employee services received in exchange for all equity awards granted including stock options based on the fair market value of the award as of the grant date.

The Company recognizes the cost of the equity awards over the period during which an employee is required to provide service in exchange for the award, usually the vesting period. As share-based compensation expense is recognized based on awards ultimately expected to vest, the expense has been reduced for estimated forfeitures based on historical forfeiture rates.

Income Taxes - The Company recognizes deferred income tax assets and liabilities for the expected future income tax consequences, based on enacted tax laws, of temporary differences between the financial reporting and tax bases of assets, liabilities and carry forwards.

The Company recognizes deferred tax assets for the expected future effects of all deductible temporary differences, loss carry forwards and tax credit carry forwards. Deferred tax assets are reduced, if deemed necessary, by a valuation allowance for any tax benefits which, based on current circumstances, are not expected to be realized. Management believes it is more likely than not that such tax benefits will be realized and a valuation allowance has not been provided.

The Company has reviewed other current outstanding statements from the FASB and does not believe that any of those statements will have a material adverse affect on the financial statements of the Company when adopted.

Future Operations

We intend to acquire new oil and gas properties and pursue new business opportunities. Long term, we intend to be prepared to pay our share of the holding and development costs associated with the Mount Emmons property.

Effects of Changes in Prices

Natural resource operations are significantly affected by changes in commodity prices. As prices for a particular mineral increase, values for that mineral typically also increase, making acquisitions of such properties more costly and sales potentially more valuable. Conversely, a price decline could enhance acquisitions of properties containing those natural resources, but could make sales of such properties more difficult. Operational impacts of changes in mineral commodity prices are common in the natural resource business. Historical and current prices for the Company's two main natural resource participation interests follow:

Oil and Gas – The ten year Cushing, OK WTI spot price for oil reached a high of $133.88 per barrel during June 2008 and a ten year low of $19.39 per barrel during December of 2001. As of December 31, 2009 the Cushing, OK WTI spot price for oil had increased to $74.47 per barrel.

The ten year U.S. Natural Gas City Gate Price reached a high of $12.48 per mcf in July of 2008 and the ten year low was $3.27 per mcf in January 2000. The price per mcf at December 31, 2009 was $6.24.

Higher oil and gas prices should positively impact our revenues going forward while lower oil and gas prices will have a negative impact not only on revenues, cash flows and profitability but also may impact ultimate reserve calculations for our wells. There is no assurance that the Company's projected 2010 investments in oil and gas properties will be profitable.

Molybdenum - The ten year high for dealer molybdenum oxide was $38 per pound in June of 2005 declined to a ten year low of $8.03 per pound in April of 2009. The mean price of molybdenum oxide at December 31, 2009 and December 31, 2008 was $11.50 per pound and $10.00 per pound, respectively. The price of molybdenum will have a direct impact on the development of Mount Emmons. Should the price for molybdenum remain at the December 2009 level or be even further reduced, the development of the Mount Emmons property could be delayed or permanently put on hold.

Contractual Obligations

Contractual obligations at December 31, 2009 consist of debt to third parties of $800,000 of which $200,000 is due in 2010, executive retirement of $915,000 and asset retirement obligations of $211,000. The executive retirement benefits are paid to former executive officers who qualify under the terms of the Company's Executive Retirement Plan. Asset retirement obligations will be satisfied during the next 34 years. The following table shows the scheduled debt payment and expenditures for budgeted asset retirement obligations as of December 31, 2009:

	(In thousands) Payments due by period				
	Total	Less than one Year	One to Three Years	Three to Five Years	More than Five Years
Long-term debt obligations	$ 800	$ 200	$ 600	$ --	$ --
Executive retirement	$ 915	153	165	--	597
Asset retirement obligation	$ 211	--	--	26	185
Totals	$ 1,926	$ 353	$ 765	$ 26	$ 782

Item 7A – Quantitative and Qualitative Disclosures About Market Risk

None

Item 8 – Financial Statements

Financial statements meeting the requirements of Regulation S-X are included below.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
U.S. Energy Corp.

We have audited the accompanying balance sheets of U.S. Energy Corp. and subsidiary (the "Company") as of December 31, 2009 and 2008, and the related statements of operations, shareholders' equity, and cash flows for each of the two years in the period ended December 31, 2009. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of U.S. Energy Corp. and subsidiary as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 12, 2010 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ Hein and Associates LLP

HEIN & ASSOCIATES LLP

Denver, Colorado
March 12, 2010

Report of Independent Registered Public Accounting Firm

Board of Directors and Shareholders ofU.S. Energy Corp.

We have audited the accompanying consolidated statements of operations, stockholders' equity and cash flows of U.S. Energy Corp. and Subsidiaries (the Company) for the year ended December 31, 2007. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated results of operations and cash flows of U.S. Energy Corp. and Subsidiaries, for the year ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note J to the consolidated financial statements, effective January 1, 2007, the Company changed its method of accounting for uncertain tax positions. As discussed in Note B to the consolidated financial statements, effective January 1, 2009, the Company changed its presentation of noncontrolling interests.

/s/ Moss Adams LLP
Scottsdale, Arizona
March 12, 2008, except as to the reclassification adjustments to reflect discontinued operations described in Note N as to which the date is March 12, 2009, and except as to the presentation of noncontrolling interests as to which the date is March 12, 2010.

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U.S. ENERGY CORP.
BALANCE SHEETS
ASSETS
(In thousands)

	December 31, 2009	December 31, 2008
CURRENT ASSETS:		
Cash and cash equivalents	$ 33,403	$ 8,434
Marketable securities		
Held to maturity - treasuries	22,059	51,152
Available for sale securities	1,178	576
Accounts receivable		
Trade	3,882	600
Reimbursable project costs	2	442
Income taxes	353	5,896
Restricted investments	--	4,929
Other current assets	1,223	738
Total current assets	62,100	72,767
INVESTMENT	2,958	3,455
PROPERTIES AND EQUIPMENT:		
Oil & gas properties under full cost method, net of $3,953 and $382 accumulated depletion, depreciation and amortization	26,002	7,906
Undeveloped mining claims	21,969	23,950
Commercial real estate, net	23,200	23,998
Property, plant and equipment, net	9,301	9,639
Net properties and equipment	80,472	65,493
OTHER ASSETS	1,193	916
Total assets	$ 146,723	$ 142,631

The accompanying notes are an integral part of these statements.

U.S. ENERGY CORP.
BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
(In thousands)

	December 31, 2009	December 31, 2008
CURRENT LIABILITIES:		
Accounts payable	$ 6,500	$ 898
Accrued compensation	1,748	682
Short-term construction debt	--	16,813
Current portion of long-term debt	200	875
Other current liabilities	224	715
Total current liabilities	8,672	19,983
LONG-TERM DEBT, net of current portion	600	1,000
DEFERRED TAX LIABILITY	7,345	8,945
ASSET RETIREMENT OBLIGATIONS	211	144
OTHER ACCRUED LIABILITIES	762	726
COMMITMENTS AND CONTINGENCIES		
SHAREHOLDERS' EQUITY:		
Common stock, $.01 par value; unlimited shares authorized; 26,418,713 and 21,935,129 shares issued, respectively	264	219
Additional paid-in capital	118,998	93,951
Accumulated surplus	9,485	17,663
Unrealized gain on marketable securities	386	--
Total shareholders' equity	129,133	111,833
Total liabilities and shareholders' equity	$ 146,723	$ 142,631

The accompanying notes are an integral part of these statements.

U.S. ENERGY CORP.
STATEMENTS OF OPERATIONS
(In thousands except per share data)

	Years ended December 31, 2009	2008	2007
OPERATING REVENUES:			
Oil & gas	$ 6,844	$ 571	--
Real estate	2,768	1,633	934
Management fees and other	15	83	240
	9,627	2,287	1,174
OPERATING COSTS AND EXPENSES:			
Oil and gas	3,919	444	--
Impairment of oil and gas properties	1,468	--	--
Real estate	2,104	1,165	380
Water treatment plant	1,636	1,462	--
Mineral holding costs	323	834	1,093
General and administrative	9,433	7,903	14,240
	18,883	11,808	15,713
OPERATING LOSS	(9,256)	(9,521)	(14,539)
OTHER INCOME & (EXPENSES):			
(Loss) gain on sales of assets	(43)	(17)	2,339
Gain on sale of uranium assets	--	--	111,728
Equity loss in unconsolidated investment	(1,374)	--	--
Loss on sale of marketable securities	--	--	(8,318)
Impairment of marketable securities	--	(1,023)	--
Gain of foreign exchange	--	--	430
Loss from dissolution of subsidiaries	--	--	(118)
Dividends	--	--	23
Interest income	314	1,426	2,800
Interest expense	(98)	(486)	(60)
	(1,201)	(100)	108,824
(LOSS) GAIN BEFORE PROVISION FOR INCOME TAXES AND DISCONTINUED OPERATIONS	(10,457)	(9,621)	94,285
INCOME TAXES:			
Current benefit from (provision for)	210	4,645	(17,589)
Deferred benefit from (provision for)	2,069	(1,319)	(14,778)
	2,279	3,326	(32,367)

(LOSS) GAIN FROM CONTINUING OPERATIONS	(8,178)	(6,295)	61,918

The accompanying notes are an integral part of these statements.

U.S. ENERGY CORP.
STATEMENTS OF OPERATIONS
(In thousands except per share data)

	Years ended December 31, 2009	2008	2007
DISCONTINUED OPERATIONS			
Loss from discontinued operations	--	(501)	(2,004)
Gain on sale of discontinued operations (net of taxes)	--	5,408	--
	--	4,907	(2,004)
NET (LOSS) INCOME	(8,178)	(1,388)	59,914
NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS	--	--	(3,551)
NET (LOSS) INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ (8,178)	$ (1,388)	$ 56,363
PER SHARE DATA			
Basic (loss) earnings from continuing operations	$ (0.38)	$ (0.27)	$ 2.85
Basic (loss) earnings from discontinued operations	--	0.21	(0.10)
Basic (loss) earnings per share	$ (0.38)	$ (0.06)	$ 2.75
Diluted (loss) earnings from continuing operations	$ (0.38)	$ (0.27)	$ 2.63
Diluted (loss) earnings from discontinued operations	--	0.21	(0.09)
Diluted (loss) earnings per share	$ (0.38)	$ (0.06)	$ 2.54
BASIC AND DILUTED WEIGHTED AVERAGE SHARES OUTSTANDING	21,604,959	23,274,978	20,469,846
DILUTED WEIGHTED AVERAGE SHARES OUTSTANDING	21,604,959	23,274,978	22,189,828

The accompanying notes are an integral part of these statements.

U.S. ENERGY CORP.
STATEMENT OF SHAREHOLDERS' EQUITY
(In thousands except share data)

	Common Stock Shares	Common Stock Amount	Additional Paid-In Capital	Retained Earnings	Unrealized Gain (Loss) on Marketable Securities	Treasury Stock Shares	Treasury Stock Amount	Unallocated ESOP Contribution	Total Shareholders' Equity
Balance December 31, 2006	19,659,591	$ 196	$ 77,481	$ (39,102)	$ 306	497,845	$ (924)	$ (491)	$ 37,466
Net income available to common shareholders	--	--	--	56,363	--	--	--	--	56,363
Unrealized loss on marketable securities	--	--	--	--	(726)	--	--	--	(726)
Unrealized tax effect on the unrealized loss	--	--	--	--	164	--	--	--	164
Comprehensive income									55,801
Income tax benefit from pre FAS 123R stock options	--	--	1,242	--	--	--	--	--	1,242
Change in basis of minority interests	--	--	--	3,898	--	--	--	--	3,898
Funding of ESOP	84,995	1	360	--	--	--	--	--	361
Issuance of common stock to outside directors	3,812	--	18	--	--	--	--	--	18
Issuance of common stock in stock compensation plan	62,500	1	318	--	--	--	--	--	319

Vesting of stock options issued to employees	--	--	607	--	--	--	--	--	607
Issuance of common stock from employee stock options	1,109,894	11	1,959	--	--	--	--	--	1,970
Issuance of common stock from stock warrants	359,598	4	1,243	--	--	--	--	--	1,247
Payment of dividend	--	--	--	(2,108)	--	--	--	--	(2,108)
Adjustment to common stock warrants	--	--	124	--	--	--	--	--	124
Release of forfeitable stock	292,740	3	1,766	--	--	--	--	--	1,769
Purchases of treasury stock	--	--	(378)	--	--	228,000	(1,047)	--	(1,425)
Issuance of common stock for the Crested merger	2,876,252	29	13,375	--	--	80,000	(41)	--	13,363
Cancellation of common stock	(856,889)	(9)	(2,003)	--	--	(805,845)	2,012	--	--
Changes in minority interest	--	--	448	--	--	--	--	--	448
Balance December 31, 2007	23,592,493	$ 236	$ 96,560	$ 19,051	$ (256)	--	$ --	$ (491)	$ 115,100

The accompanying notes are an integral part of these statements.

U.S. ENERGY CORP.
STATEMENT OF SHAREHOLDERS' EQUITY
(continued)
(In thousands except share data)

	Common Stock Shares	Common Stock Amount	Additional Paid-In Capital	Retained Earnings	Unrealized Gain (Loss) on Marketable Securities	Unallocated ESOP Contribution	Total Shareholders' Equity
Balance December 31, 2007	23,592,493	$ 236	$ 96,560	$ 19,051	$ (256)	$ (491)	$ 115,100
Net loss available to common shareholders	--	--	--	(1,388)	--	--	(1,388)
Recognized impairment on marketable securities	--	--	--	--	256	--	256
Unrealized tax effect on on the unrealized loss	--	--	--	--	--	--	--
Comprehensive (loss)							(1,132)
Funding of ESOP	126,878	1	207	--	--	--	208
Vesting of stock warrants to outside contractor	--	--	30	--	--	--	30
Issuance of common stock 2001 stock compensation plan	85,000	1	283	--	--	--	284
Vesting of stock options issued to employees	--	--	1,151	--	--	--	1,151
Vesting of stock options issued to outside directors	--	--	17	--	--	--	17

Cancellation of common stock from the ESOP	(155,811)	(2)	(489)	--	--	491	--
Issuance of common stock from stock warrants	446,698	5	1,523	--	--	--	1,528
Deferred tax on FAS 123R compensation	--	--	202	--	--	--	202
Common stock buy back program	(2,160,129)	(22)	(5,533)	--	--	--	(5,555)
Balance December 31, 2008	21,935,129	$ 219	$ 93,951	$ 17,663	$ --	$ --	$ 111,833

The accompanying notes are an integral part of these statements.

U.S. ENERGY CORP
STATEMENT OF SHAREHOLDERS' EQUITY
(continued)
(In thousands except share data)

	Common Stock Shares	Common Stock Amount	Additional Paid-In Capital	Retained Earnings	Unrealized Gain on Marketable Securities	Total Shareholders' Equity
Balance December 31, 2008	21,935,129	$ 219	$ 93,951	$ 17,663	$ --	$ 111,833
Net loss available to common shareholders	--	--	--	(8,178)	--	(8,178)
Unrecognized gain on marketable securities	--	--	--	--	602	602
Unrealized tax effect on on the unrealized gain	--	--	--	--	(216)	(216)
Comprehensive (loss)						(7,792)
Issuance of common stock	5,000,000	50	24,267	--	--	24,317
Funding of ESOP	36,583	--	217	--	--	217
Issuance of common stock 2001 stock compensation plan	80,000	1	185	--	--	186
Issuance of common stock from stock warrants	71,088	1	232	--	--	233
Issuance of common stock from stock options	1,984	--	5	--	--	5
Vesting of stock options	--	--	1,430	--	--	1,430

issued to employees						
Vesting of stock warrants						
to outside contractor	--	--	9	--	--	9
Vesting of stock options						
issued to outside directors	--	--	56	--	--	56
Excess tax benefit on the exercise						
stock options and warrants	--	--	38	--	--	38
Common stock buy back program	(706,071)	(7)	(1,392)	--	--	(1,399)
Balance December 31, 2009	26,418,713	$ 264	$ 118,998	$ 9,485	$ 386	$ 129,133

The accompanying notes are an integral part of these statements.

U.S. ENERGY CORP.
STATEMENTS OF CASH FLOWS

	(In thousands) For the years ended December 31, 2009	2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net (loss) income	$ (8,178)	$ (1,388)	$ 59,914
Gain on the sale of SGMI stock	--	(5,408)	--
Loss from discontinued operations	--	501	2,004
(Loss) gain from continuing operations	(8,178)	(6,295)	61,918
Reconcile net loss to net cash used in operations:			
Depreciation, depletion and amortization	5,066	1,426	438
Accretion of discount on treasury investment	(183)	(1,255)	--
Impairment of marketable securities	--	1,023	--
Impairment of oil and gas properties	1,468	--	--
Gain on sale of assets to Uranium One	--	--	(111,728)
Gain on foreign exchange	--	--	(430)
Loss on sale of marketable securities	--	--	8,318
Equity loss from Standard Steam	1,374	--	--
Deferred income taxes	(2,069)	1,319	14,778
Loss (gain) on sale of assets	43	17	(2,356)
Noncash compensation	1,935	2,536	1,284
Noncash services	65	46	142
Net changes in assets and liabilities			
Accounts receivable	(2,843)	(342)	(755)
Income tax receivable	5,543	(3,809)	(903)
Other current assets	(192)	(18)	(246)
Accounts payable	80	(692)	680
Accrued compensation	1,000	(283)	(958)
Other liabilities	(557)	(209)	377
NET CASH PROVIDED BY (USED IN) OPERATING ACTIVITIES	2,552	(6,536)	(29,441)

The accompanying notes are an integral part of these statements.

U.S. ENERGY CORP.
STATEMENTS OF CASH FLOWS

	(In thousands) For the years ended December 31, 2009	2008	2007
CASH FLOWS FROM INVESTING ACTIVITIES:			
Net redemption (investment in) treasury investments	$ 29,277	$ (49,897)	$ --
Investment in Standard Steam	(877)	(3,455)	--
Acquisition and development of real estate	(3)	(11,597)	(7,517)
Acquisition and development of oil and gas properties	(17,498)	(5,354)	(2,910)
Acquisition and development of mining properties	(1)	(2,905)	(485)
Minining property option payment	2,000	--	--
Acquisition of property and equipment	(410)	(294)	(6,429)
Proceeds from sale of property and equipment	11	1,103	3,978
Proceeds from sale of marketable securities	--	--	92,251
Proceeds from sale of uranium assets	--	--	14,023
Net change in notes receivable	--	--	560
Net change in investments in affiliates	--	--	349
Net change in restricted investments	4,651	1,842	(7,000)
NET CASH PROVIDED BY (USED IN) INVESTING ACTIVITIES	17,150	(70,557)	86,820
CASH FLOWS FROM FINANCING ACTIVITIES:			
Issuance of common stock	$ 24,516	1,528	3,217
Issuance of subsidiary stock	--	--	340
Tax benefit from the exercise of stock options	38	--	1,242
Payment of cash dividend	--	--	(2,108)
Proceeds from short-term construction debt	--	11,423	--
Proceeds from long term debt	--	1,875	164
Repayments of debt	(17,888)	(362)	(1,134)
Stock buyback program	(1,399)	(5,554)	(1,466)
NET CASH PROVIDED BY			

FINANCING ACTIVITIES	5,267	8,910	255
Net cash used in operating activities of discontinued operations	--	(76)	(2,260)
Net cash provided by (used in) investing activities of discontinued operations	--	4,402	(56)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	24,969	(63,857)	55,318
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	8,434	72,292	16,974
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 33,403	$ 8,434	$ 72,292

The accompanying notes are an integral part of these statements.

U.S. ENERGY CORP.
STATEMENTS OF CASH FLOWS

	(In thousands) For the years ended December 31, 2009	2008	2007
SUPPLEMENTAL DISCLOSURES:			
Income tax (received) paid	$ (5,753)	$ (945)	$ 17,250
Interest paid	$ 39	$ 69	$ 60
NON-CASH INVESTING AND FINANCING ACTIVITIES:			
Unrealized gain	$ 386	$ --	$ 563
Acquisition & development of oil and gas properties through accounts payable	$ 5,522	$ --	$ --
Acquisition & development of oil and gas properties through asset retirement obligations	$ 58	$ --	$ --
Development of mining properties properties through asset retirement obligations	$ 9	$ --	$ --

The accompanying notes are an integral part of these statements.

U.S. ENERGY CORP.
NOTES TO FINANCIAL STATEMENTS
DECEMBER 31, 2009, 2008 and 2007

A. BUSINESS ORGANIZATION AND OPERATIONS

U.S. Energy Corp. was incorporated in the State of Wyoming on January 26, 1966. U.S. Energy Corp. (the "Company" or "USE") engages in the acquisition, exploration, holding, sale and/or development of mineral properties. Principal asset interests at December 31, 2009 are in oil and gas, molybdenum, geothermal and real estate. Historically, the Company also participated in other base and precious metals. Our uranium and gold assets were sold during 2008 and 2007.

B. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates include oil and gas reserves used for depletion and impairment considerations and the cost of future asset retirement obligations. Due to inherent uncertainties, including the future prices of oil and gas, these estimates could change in the near term and such changes could be material.

Principles of Consolidation

The financial statements of the Company as of December 31, 2009 and December 31, 2008 include only the accounts of the Company and its wholly owned subsidiary Remington Village, LLC ("Remington Village"). The consolidated financial statements contained in this report for the year ended December 31, 2007 also include subsidiaries of the Company which were either merged into the Company or liquidated and dissolved during 2008 and 2007. These subsidiaries were majority-owned or controlled subsidiaries: Plateau Resources Limited, ("Plateau") (100%), Four Nines Gold, Inc. ("FNG") (50.9%), SGMI (54.4%), Yellow Stone Fuels, Inc. ("YSFI") (49.1%), Crested Corp. ("Crested") (70.9%), and the USECC Joint Venture ("USECC"), a consolidated joint venture which was equally owned by the Company and Crested. On December 15, 2008, the Company purchased a 25% ownership interest in Standard Steam Trust LLC ("SST") which is accounted for using the equity method. At December 31, 2009 the Company's ownership interest in SST was reduced to 23.8%.

Cash and Cash Equivalents

The Company considers all highly liquid investments with original maturities of three months or less to be cash equivalents. The Company maintains its cash and cash equivalents in bank deposit accounts which exceed federally insured limits. At December 31, 2009 and 2008, the Company had its cash and cash equivalents with several financial institutions, primarily invested in U.S. Treasury Bills. The Company has not experienced any losses in such accounts and believes it is not exposed to any significant credit risk on cash and cash equivalents.

Marketable Securities

The Company categorizes its marketable securities as available-for-sale or held-to-maturity. Increases or decreases in the fair value which are considered temporary are recorded within equity as comprehensive income or losses. Gains or losses as a result of sale are recorded in operations when realized.

U.S. ENERGY CORP.
NOTES TO FINANCIAL STATEMENTS
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(Continued)

Accounts Receivable

The Company determines any required allowance by considering a number of factors including the length of time trade and other accounts receivable are past due and the Company's previous loss history. The Company provides reserves for account receivable balances when they become uncollectable. Payments subsequently received on such reserved receivables are credited to the allowance for doubtful accounts. During the year ended December 31, 2009, the Company recorded $109,000 in uncollectable receivables related to its multi family housing project. The balance of accounts receivable at December 31, 2009 are for the sale of oil and gas and have been received subsequent to the balance sheet date. No reserve for uncollectable receivables was booked during the year ended December 31, 2009 and 2008.

Restricted Investments

The Company accounts for cash deposits held as collateral for reclamation obligations as restricted investments. Maturities or release dates less than twelve months from the end of the reported accounting period are reported as current assets while maturities or release dates in excess of twelve months from report dates are reported as long term assets.

Properties and Equipment

Land, buildings, improvements, machinery and equipment are carried at cost. Depreciation of buildings, improvements, machinery and equipment is provided principally by the straight-line method over estimated useful lives ranging from 3 to 45 years. Following is a breakdown of the lives over which assets are depreciated:

Machinery and Equipment:		
	Office Equipment	3 to 5 years
	Planes	15 years
	Field Tools and Hand Equipment	5 to 7 years
	Vehicles and Trucks	3 to 7 years
	Heavy Equipment	7 to 10 years
Buildings and Improvements:		
	Service Buildings	20 years
	Corporate Headquarter Building	45 years

U.S. ENERGY CORP.
NOTES TO FINANCIAL STATEMENTS
DECEMBER 31, 2009, 2008 and 2007
(Continued)

Components of Property and Equipment as of December 31, 2009 and 2008 are as follows:

	(In thousands) December 31, 2009	2008
Oil & gas properties		
Unevaluated	$ 3,993	$ 2,968
Well in progress	1,367	--
Evaluated	24,595	5,320
	29,955	8,288
Less accumulated depreciation depletion and amortization	(3,953)	(382)
Net book value	$ 26,002	$ 7,906
Mining properties	$ 21,969	$ 23,950
Commercial real estate	$ 24,600	$ 24,467
Less accumulated depreciation depletion and amortization	(1,400)	(469)
Net book value	$ 23,200	$ 23,998
Building, land and equipment	$ 14,196	14,399
Less accumulated depreciation depletion and amortization	(4,895)	(4,760)
Net book value	$ 9,301	$ 9,639
Totals	$ 80,472	$ 65,493

Oil and Gas Properties

The Company follows the full cost method in accounting for its oil and gas properties. 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.

U.S. ENERGY CORP.
NOTES TO FINANCIAL STATEMENTS
DECEMBER 31, 2009, 2008 and 2007
(Continued)

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 average prices per barrel of oil and per MMbtu of natural gas at the first of each month in the 12-month period prior to the end of the reporting period and costs, adjusted for contract provisions, financial derivatives that hedge the Company's oil and gas revenue and asset retirement obligations, (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 differences between the book and tax basis of 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. During the year ended December 31, 2009, the Company recorded a non-cash impairment of $1.1 million during the quarter ended March 31, 2009 and $404,000 during the quarter ended September 30, 2009.

Mineral Properties

The Company capitalizes all costs incidental to the acquisition of mineral properties. Mineral exploration costs are expensed as incurred. When exploration work indicates that a mineral property can be economically developed as a result of establishing proved and probable reserves, costs for the development of the mineral property as well as capital purchases and capital construction are capitalized and amortized using units of production over the estimated recoverable proved and probable reserves. Costs and expenses related to general corporate overhead are expensed as incurred. All capitalized costs are charged to operations if the Company subsequently determines that the property is not economical due to permanent decreases in market prices of commodities, excessive production costs or depletion of the mineral resource.

Mineral properties at December 31, 2009 and 2008 reflect capitalized costs associated with the Company's Mount Emmons molybdenum property near Crested Butte, Colorado. The Company has entered into an agreement with Thompson Creek Metals Company USA ("TCM") to develop this property. TCM may earn up to a 75% interest in the project for the investment of $400 million. The Company's carrying balance in the Mount Emmons property at December 31, 2009 and 2008 is as follows (in thousands):

Costs associated with Mount Emmons	
at December 31, 2008	$ 23,950
Development costs during the year ended December 31, 2009	9
Accretion of asset retirement obligation	10
Option payments received from TCM	
January, 2009	(1,000)
December, 2009	(1,000)
Costs at December 31, 2009	$ 21,969

U.S. ENERGY CORP.
NOTES TO FINANCIAL STATEMENTS
DECEMBER 31, 2009, 2008 and 2007
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Long-Lived Assets – Real Estate

The Company evaluates its long-lived assets, which consist of commercial real estate, for impairment when events or changes in circumstances indicate that the related carrying amount may not be recoverable. Impairment calculations are generally based on market appraisals. If estimated future cash flows, on an undiscounted basis, are less than the carrying amount of the related asset, an asset impairment is considered to exist. Changes in significant assumptions underlying future cash flow estimates may have a material effect on the Company's financial position and results of operations. At December 31, 2009 and 2008, no impairment existed on the Company’s long-lived assets as the appraised value at December 31, 2009 and 2008 exceeded construction and carrying value and rental rates remained strong and costs within projected limits.

Fair Value of Financial Instruments

The carrying amount of cash equivalents, receivables, other current assets, accounts payable and accrued expenses approximate fair value because of the short-term nature of those instruments. The recorded amounts for short-term and long-term debt approximate the fair market value due to the variable nature of the interest rates on the short-term debt, and the fact that interest rates remain generally unchanged from issuance of the long-term debt.

Asset Retirement Obligations

The Company accounts for its asset retirement obligations under FASB ASC 410-20, "Asset Retirement Obligations." The Company records the fair value of the reclamation liability on its inactive mining properties and its operating oil and gas properties as of the date that the liability is incurred. The Company reviews the liability each quarter and determines if a change in estimate is required as well as accretes the discounted liability on a quarterly basis for the future liability. Final determinations are made during the fourth quarter of each year. The Company deducts any actual funds expended for reclamation during the quarter in which it occurs.

The following is a reconciliation of the total liability for asset retirement obligations:

	(In thousands) For the years ended December 31,	
	2009	2008
Beginning asset retirement obligation	$ 144	$ 133
Accretion of discount	12	9
Liabilities incurred	55	25
Liabilities settled	--	(23)
Ending asset retirement obligation	$ 211	$ 144
	December 31,	
	2009	2008

Mining properties	$ 128	$ 119
Oil & Gas Wells	83	25
Ending asset retirement obligation	$ 211	$ 144

U.S. ENERGY CORP.
NOTES TO FINANCIAL STATEMENTS
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(Continued)

Revenue Recognition

The Company records natural gas and oil revenue under the sales method of accounting. Under the sales method, the Company recognizes revenues based on the amount of natural gas or oil sold to purchasers, which may differ from the amounts to which the Company is entitled based on its interest in the properties. Natural gas balancing obligations as of December 31, 2009 and 2008 were not significant.

Revenues from real estate operations are reported on a gross revenue basis and are recorded at the time the service is provided.

Management fees are recorded when the service is provided. Management fees are for operating and overseeing services performed on mineral properties in which the Company participates with joint venture or industry partners.

Stock Based Compensation

The Company measures the cost of employee services received in exchange for all equity awards granted including stock options based on the fair market value of the award as of the grant date.

The Company has computed the fair values of its options granted to employees using the Black Scholes pricing model and the following weighted average assumptions:

	For the year ended December 31,		
	2009	2008	2007
Risk-free interest rate	--	3.23 %	4.82 %
Expected lives (years)	--	6.00	10.00
Expected volatility	--	56.51 %	48.80 %
Expected dividend yield	--	--	--

The Company recognizes the cost of the equity awards over the period during which an employee is required to provide service in exchange for the award, usually the vesting period. As share-based compensation expense is recognized based on awards ultimately expected to vest, the expense has been reduced for estimated forfeitures based on historical forfeiture rates.

Income Taxes

The Company recognizes deferred income tax assets and liabilities for the expected future income tax consequences, based on enacted tax laws, of temporary differences between the financial reporting and tax bases of assets, liabilities and carry forwards.

Additionally, the Company recognizes deferred tax assets for the expected future effects of all deductible temporary differences, loss carry forwards and tax credit carry forwards. Deferred tax assets are reduced, if deemed necessary, by a valuation allowance for any tax benefits which, based on current circumstances, are not expected to be realized. Management believes it is more likely than not that such tax benefits will be realized and a valuation allowance has not been provided.

U.S. ENERGY CORP.
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Net Income (Loss) Per Share

Basic earnings per share are computed based on the weighted average number of common shares outstanding. Common shares held by the ESOP are included in the computation of earnings per share. Total shares held by the ESOP at December 31, 2009, 2008, and 2007 were 642,913, 606,330 and 541,735, respectively. Diluted earnings per share is computed based on the weighted average number of common shares outstanding adjusted for the incremental shares attributed to outstanding options and warrants to purchase common stock, if dilutive. Using the treasury stock method, potential common shares relating to options and warrants are excluded from the computation of diluted loss per share for the years ending December 31, 2009 and 2008 because they were anti dilutive. Potential shares relating to options and warrants were included in the diluted earnings per share for the year ended December 31, 2007. Dilutive options and warrants totaled 282,504, 226,246, and 1,719,982 at December 31, 2009, 2008 and 2007, respectively.

Recent Accounting Pronouncements

FASB Codification Discussion - We follow accounting standards set by the Financial Accounting Standards Board, commonly referred to as the “FASB.” The FASB sets generally accepted accounting principles (GAAP) that we follow to ensure we consistently report our financial condition, results of operations, and cash flows.

The FASB recognized the complexity of its standard-setting process and embarked on a revised process in 2004 that culminated in the release on July 1, 2009, of the FASB Accounting Standards Codification,™ sometimes referred to as the Codification or ASC. The Codification does not change how the Company accounts for its transactions or the nature of related disclosures made. However, when referring to guidance issued by the FASB, the Company refers to topics in the ASC. The above change was made effective by the FASB for periods ending on or after September 15, 2009.

FASB ASC 810-10 - In June 2009, the FASB issued an amendment to ASC 810-10, Consolidation. As a result, in December 2009, the FASB issued ASC 2009-17, Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities. This guidance amends ASC 810-10-15 to replace the quantitative-based risks and rewards calculation for determining which enterprise has a controlling financial interest in a Variable Interest Entity (“VIE”) with a primarily qualitative approach focused on identifying which enterprise has the power to direct the activities of a VIE that most significantly impact the entity’s economic performance. It also requires ongoing assessments of whether an enterprise is the primary beneficiary of a VIE and requires additional disclosures about an enterprise’s involvement in VIEs. This guidance is effective as of the beginning of the reporting entity’s first annual reporting period that begins after November 15, 2009 and earlier adoption is not permitted. The adoption of ASC 810-10 is not expected to have a material effect on our financial position and results of operations.

U.S. ENERGY CORP.
NOTES TO FINANCIAL STATEMENTS
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FASB ASC 810-10-65 - In December 2007, the FASB issued guidance now codified as ASC Section 810-10-65, "Consolidation—Transition and Open Effective Date Information" ("ASC 810-10-65"), which requires companies to treat non-controlling interests (commonly referred to as minority interest) as a separate component of shareholders' equity and not as a liability. This pronouncement will apply prospectively, except for the presentation and disclosure requirements, which will apply retrospectively. ASC 810-10-65 is effective for periods beginning on or after December 15, 2008 and will impact the accounting for non-controlling interests after the effective date, to the extent the Company enters into an acquisition with a non-controlling interest. The adoption of this standard resulted in a different presentation of noncontrolling interests on the Company's consolidated financial statements.

FASC ASC 815-10-50 - In March 2008, the FASB issued guidance related to the disclosures about derivative instruments and hedging activities under FASB ASC 815-10-50, Derivatives and Hedging. This guidance requires companies to provide enhanced disclosures about (a) how and why they use derivative instruments, (b) how derivative instruments and related hedged items are accounted for under applicable guidance, and (c) how derivative instruments and related hedged items affect a company's financial position, financial performance, and cash flows. These disclosure requirements are effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. The Company has no hedges in place as of December 31, 2009. If the Company elects to hedge production in 2010 it will comply with FASB ASC 815-10-50.

Accounting Standards Update No. 2009-01 - In June 2009, the FASB issued Accounting Standards Update No. 2009-01 which amends ASC 105, Generally Accepted Accounting Principles. This guidance states that the ASC will become the source of authoritative U.S. GAAP recognized by the FASB to be applied by nongovernmental entities. Once effective, the Codification's content will carry the same level of authority. Thus, the U.S. GAAP hierarchy will be modified to include only two levels of U.S. GAAP: authoritative and non-authoritative. This is effective for financial statements issued for interim and annual periods ending after September 15, 2009. The Company adopted ASC 105 as of September 30, 2009 and thus have incorporated the new Codification citations in place of the corresponding references to legacy accounting pronouncements.

Accounting Standards Update No. 2010-03 - In December 2008, the Securities and Exchange Commission published a Final Rule, Modernization of the Oil and Gas Reporting Requirements. The new rule permits the use of new technologies to determine proved reserves if those technologies have been demonstrated to lead to reliable conclusions about reserves volumes. The new requirements also allow companies to disclose their probable and possible reserves to investors. In addition, the new disclosure requirements require companies to: (a) report the independence and qualifications of its reserves preparer or auditor; (b) file reports when a third party is relied upon to prepare reserves estimates or conducts a reserves audit; and (c) report oil and gas reserves using an average price based upon the prior 12-month period rather than year-end prices. The use of average prices will affect impairment and depletion calculations. In January 2010, the FASB issued Accounting Standards Update No. 2010-03, Oil and Gas Reserve Estimation and Disclosure, to align the oil and gas reserve estimation and disclosure requirement of the SEC Final Rule with the ASC 932. The new disclosure requirements are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. The Company's adoption of this Final rule for this annual reported dated December 31, 2009 affected our oil and gas disclosures but had no material effect on our financial position and results of operations.

U.S. ENERGY CORP.
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Accounting Standards Update No. 2009-05 - In August 2009, the FASB issued Accounting Standards Update No. 2009-05, Measuring Liabilities at Fair Value, which amends ASC 820, Fair Value Measurements and Disclosures. This Update provides clarification that in circumstances in which a quoted price in an active market for the identical liability is not available, a reporting entity is required to measure the fair value using one or more of the following techniques: a valuation technique that uses the quoted price of the identical liability or similar liabilities when traded as an asset, which would be considered a Level 1 input, or another valuation technique that is consistent with ASC 820. This Update is effective for the first reporting period (including interim periods) beginning after issuance. The Company adopted this guidance as of September 30, 2009, which did not have a material impact on our consolidated financial statements.

Accounting Standards Update 2010-09 - In May 2009, the FASB issued FASB ASC 855, "Subsequent Events," and in February 2010, the FASB issued ASC Update 2010-09, "Subsequent Events (Topic 855) – Amendments to Certain Recognition and Disclosure Requirements," which establishes standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued. Under this standard, entities that file or furnish financial statements with the SEC, such as the Company, are required to use an issued date in evaluating subsequent events. This standard, as updated, is effective February 24, 2010, and the Company adopted it at that date. The adoption did not have a material impact on the Company's results of operations or financial position.

The Company has reviewed other current outstanding statements from the FASB and does not believe that any of those statements will have a material adverse affect on the financial statements of the Company when adopted.

C. RELATED-PARTY TRANSACTIONS

Sutter Gold Mining Company, Inc. ("SGMI")

On August 22, 2008, the Company sold 39,062,720 common shares of SGMI that it owned, to RMB Resources Ltd. ("RMB"), as trustee for the Telluride Investment Trust. The sale of these shares represented approximately 49.9% of the outstanding common shares of SGMI for purchase price of $5.1 million. Under the terms of the agreement, the Company retained an equity position of approximately 3,550,361 shares and the 5% net profits interest royalty. The Company also participated in a non-brokered private placement by SGMI with the purchase of 4,545,455 units for total cash consideration of $496,000. Based on these transactions, the Company owns approximately 8,095,816 shares or 7.8% of SGMI. As a result of participating in the private placement the Company also received 24-month warrants to purchase an additional 2,272,728 common shares of SGMI at a price of Cdn. $0.15 per share.

The Company recorded a gain of $5.4 million from the sale of its controlling interest in SGMI during the year ended December 31, 2008. The Company also recorded losses from discontinued operations of SGMI of $501,000 and $2.0 million for the years ended December 31, 2008 and 2007, respectively.

U.S. ENERGY CORP.
NOTES TO FINANCIAL STATEMENTS
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D. FAIR VALUE

The Company adopted Financial Accounting Standards Board Accounting Standards Codification Topic 820 "Fair Value Measurements and Disclosures" (FASB ASC 820) on January 1, 2008, as it relates to financial assets and liabilities. The Company adopted FASB ASC 820 on January 1, 2009, as it relates to nonfinancial assets and liabilities. FASB ASC 820 establishes a fair value hierarchy that prioritizes the inputs the Company to measure fair value. The three levels of the fair value hierarchy defined by FASB ASC 820 are as follows:

- Level 1 — Unadjusted quoted prices is available in active markets for identical assets or liabilities.
- Level 2 — Pricing inputs, other than quoted prices within Level 1, which are either directly or indirectly observable.
- Level 3 — Pricing inputs that are unobservable requiring the Company of valuation methodologies that result in management's best estimate of fair value.

The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the nonfinancial assets and liabilities and their placement in the fair value hierarchy levels. The fair value of the Company's asset retirement obligations and other accrued liabilities are determined using discounted cash flow methodologies based on inputs that are not readily available in public markets. The fair value of the asset retirement obligations and other accrued liabilities are reflected on the balance sheet as detailed below.

		Fair Value Measurements at December 31, 2009 Using		
Description	December 31, 2009	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Asset retirement obligations	$ 211	$ --	$ --	$ 211
Other accrued liabilities	762	--	--	762
Total	$ 973	$ --	$ --	$ 973

		Fair Value Measurements at December 31, 2008 Using		
	December 31,	Quoted Prices in Active	Significant Other Observable	Significant Unobservable Inputs

Description	2008	Markets for Identical Assets (Level 1)	Inputs (Level 2)	(Level 3)
Asset retirement obligations	$ 144	$ --	$ --	$ 144
Other accrued liabilities	726	--	--	726
Total	$ 870	$ --	$ --	$ 870

See Note B for a roll forward of the asset retirement obligation.

U.S. ENERGY CORP.
NOTES TO FINANCIAL STATEMENTS
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(Continued)

As of December 31, 2009, the Company held $23.2 million of investments in government securities and marketable securities. The fair value of the investments is reflected on the balance sheet as detailed below.

		Fair Value Measurements at December 31, 2009 Using		
Description	December 31, 2009	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Held to maturity - treasuries	$ 22,059	$ 22,059	$ --	$ --
Available for sale securities	1,178	1,178	--	--
Total	$ 23,237	$ 23,237	$ --	$ --

		Fair Value Measurements at December 31, 2008 Using		
Description	December 31, 2008	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Held to maturity - treasuries	$ 51,152	$ 51,152	$ --	$ --
Available for sale securities	576	576	--	--
Total	$ 51,728	$ 51,728	$ --	$ --

The following table summarizes, by major security type, the fair value and any unrealized gain of the Company's investments. The unrealized gain is recorded on the consolidated balance sheet as other comprehensive income, a component of stockholders' equity.

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December 31, 2009

	Less Than 12 Months		12 Months or Greater		Total	
Description of Securities	Fair Value	Unrealized (Loss)/Gain	Fair Value	Unrealized (Loss)/Gain	Fair Value	Unrealized (Loss)/Gain
Held to maturity - treasuries	$ 22,059	$ --	$ --	$ --	$ 22,059	$ --
Available for sale securities	1,178	602	--	--	1,178	602
Total	$ 23,237	$ 602	$ --	$ --	$ 23,237	$ 602

December 31, 2008

	Less Than 12 Months		12 Months or Greater		Total	
Description of Securities	Fair Value	Unrealized (Loss)/Gain	Fair Value	Unrealized (Loss)/Gain	Fair Value	Unrealized (Loss)/Gain
Held to maturity - treasuries	$ 51,152	$ --	$ --	$ --	$ 51,152	$ --
Available for sale securities	576	--	--	--	576	--
Total	$ 51,728	$ --	$ --	$ --	$ 51,728	$ --

The Company’s other financial instruments include cash and cash equivalents, accounts receivable, accounts payable, other current liabilities and long-term debt and short-term construction debt. The carrying amount of cash and cash equivalents, accounts receivable, accounts payable and other current liabilities approximate fair value because of their immediate or short-term maturities. The carrying value of the Company long-term debt approximates its fair market value since it interest rates have remained generally unchanged from the issuance of the long-term debt. The carrying value of the Company short-term construction debt, at December 31, 2008, approximates its fair market value since it bears interest at a floating market interest rate. The following are estimated fair values and carrying values of our other financial instruments at each of these dates:

	December 31, 2009		December 31, 2008	
Description	Carry Amount	Fair Value	Carry Amount	Fair Value

Long-term debt	$ 800	$ 800	$ 1,875	$ 1,875
Short-term construction debt	$ --	$ --	$ 16,813	$ 16,813

E. MINERAL PROPERTY TRANSACTIONS

Mount Emmons Molybdenum Properties

On August 19, 2008, USE and Thompson Creek Metals Company USA ("TCM"), a Colorado corporation headquartered in Englewood, Colorado, entered into an Exploration, Development and Mine Operating Agreement for USE's 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).

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The Agreement covers two distinct periods of time: The Option Period, during which TCM may exercise an option (the "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 USE and also have an option to acquire up to an additional 25% interest in Mount Emmons. The following table sets forth the required option and property expenditures that Thompson Creek must make to own its interest in the Mount Emmons molybdenum property:

	(In thousands) Option Payments to U.S. Energy	Expenditures by Thompson Creek on the Project	Total	
Closing	$ 500		$ 500	(1)
December 31, 2008		2,000	2,000	(2)
January 1, 2009	1,000		1,000	(3)
December 31, 2009		4,000	4,000	(4)
January 1, 2010	1,000		1,000	(5)
December 31, 2010		4,000	4,000	
January 31, 2011	1,000		1,000	
June 30, 2011		1,500	1,500	
Total - First Stage	$ 3,500	$ 11,500	$ 15,000	(6)
January 2012	$ 1,000		$ 1,000	
January 2013	1,000		1,000	
January 2014	1,000		1,000	
Stage Two Expenditures		32,000	32,000	(7)
Total - Second Stage	$ 3,000	$ 32,000	$ 35,000	(8)
Stage Three Expenditures	$ --	$ 350,000	$ 350,000	(9)
	$ 6,500	$ 393,500	$ 400,000	

(1) Paid at Closing on September 11, 2008
(2) Paid during the twelve months ended December 31, 2008
(3) Paid on January 2, 2009
(4) Paid $3,847,600 and deposited $142,400 into escrow for the project
(5) Paid on December 31, 2009
(6) If Thompson Creek has paid a total of $15 million it will own 15%
(7) To be paid for the development of the project by July 31, 2018
(8) If Thompson Creek has paid a total of $50 million it will own 50%
(9) If Thompson Creek pays 100% of the next $350 million it will own 75% of the project.

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Costs to operate the water treatment plant at the property will be paid solely by USE until TCM elects to exercise its option to own an interest in the property.

Failure by TCM to incur the required amount of expenditures by a deadline, or make an Option Payment to USE, subject to the terms of the Agreement, the Agreement may be terminated without further obligation to USE 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 USE, 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% USE. 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 USE and TCM then would share expenditures in accordance with their participation interests at that date, in accordance with the Joint Venture. 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 the Project Manager of Mount Emmons. A four person Management Committee governs the projects' operations, with two representatives each from USE 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 USE's 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.

Oil and Gas Exploration

The Company participates in oil and gas projects as a non-operating working interest owner and has active agreements with several oil and gas exploration and production companies. Our working interest varies by project, but typically ranges from approximately 5% to 65%. These projects may result in numerous wells being drilled over the next three to five years.

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On August 24, 2009, the Company and Brigham Oil & Gas, L.P. ("Brigham") a Delaware limited partnership wholly-owned by Brigham Exploration Company (a Delaware corporation), entered into a Drilling Participation Agreement (the "DPA"). The DPA provides for the Company and Brigham to jointly explore for oil in the Bakken and Three Forks formations, in up to fifteen 1,280 acre spacing units (19,200 gross acres) in a portion of Brigham's Rough Rider prospect in Williams and McKenzie Counties, North Dakota. The terms of the DPA call for the drilling of up to 15 initial Bakken wells in 15 separate 1,280 acre spacing units. Under the terms of the DPA, the Company committed to drilling six initial wells (and earning subsequent working interests in six 1,280 acre spacing units) and exercised its option to drill nine additional wells (and earning subsequent working interests in nine additional 1,280 acre spacing units). Upon the drilling and completion of the first or initial well in each 1,280 acre spacing unit, the Company will earn 36% of Brigham's original working interest in the remaining acreage (or drilling locations) in each 1,280 acre unit or 19,200 gross acres in the Rough Rider project area.

Under the DPA the wells to be drilled are broken into three groups. The first group consists of six wells, the second group of four wells and the final of five wells. The Company participated for 65% of Brigham's original working interest in each initial well drilled in the first six well program. As of December 31, 2009, Brigham elected to participate in the next 9 wells at 50% of their working interest which decreased the Company's participation in those wells to 50% from the 65% participation interest on the first six wells. Each participation amount for both Brigham and the Company will be subject to dilution or expansion based on other working interest owners' participation in the initial wells and/or subsequent wells in each 1,280 acre spacing unit. Upon receiving a pooled payout of all of the costs and expenses incurred to drill and complete the six initial wells in the six initial 1,280 acre spacing units, the Company will assign back 35% of its 65% of Brigham's original working interest to Brigham after which the Company will own 42.25% of Brigham's original working interest in the initial well in each 1,280 acre spacing unit. The Company is also entitled to a pooled payout on the second group of four wells similar to the first six well program. Participation in the third group of five wells and spacing units entitles the Company to a well by initial well per spacing unit payout before a 27.7% back in assignment to Brigham.

At December 31, 2009, 6 wells, 2.99 net wells to the Company, had been drilled and completed with net costs of $18.7 million. There were an additional 2 wells, 0.58 net wells to the Company, being drilled at December 31, 2009 at a net cost of $1.4 million. The remaining seven wells will be drilled during 2010. As a result of participating in all 15 wells, the Company will earn the rights to drill up to 30 total wells in the Bakken formation and an additional 30 wells in the Three Forks formation for a total of 60 wells, based on current spacing in North Dakota. Brigham operates all of the wells. If the spacing is ultimately increased to three wells per 1,280 acre spacing unit, the potential number of drilling locations could increase to 90. The drilling of each well typically takes 30 days while the completion typically takes 21-28 days.

Full cost pool capitalized costs are amortized over the life of production of proven properties. Capitalized costs at December 31, 2009 and 2008 which were not included in the amortized cost pool were $5.4 and $3.0 million, respectively. These costs consist of wells in progress, seismic costs that are being analyzed for potential drilling locations as well as land costs and are related to unproved properties. No capitalized costs related to unproved properties are included in the amortization base at December 31, 2009 and 2008. It is anticipated that these costs will be added to the full cost amortization pool in the next two years as properties are evaluated, drilled or abandoned.

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Ceiling Test Analysis – The Company performs a quarterly ceiling test for each of its oil and gas cost centers, which in 2009, there was only one. The ceiling test incorporates assumptions regarding pricing and discount rates and over which management has no influence in the determination of present value. In arriving at the ceiling test for the quarter ended December 31, 2009, the Company used $61.18 per barrel for oil and $3.866 per MMbtu for natural gas (and adjusted for property specific gravity, quality, local markets and distance from markets) to compute the future cash flows of the Company's producing property. The discount factor used was 10%.

During the year ended December 31, 2009, the Company recorded impairments totaling $1.5 million, $1.1 million in the first quarter of 2009 and $405,000 in the third quarter of 2009. This impairment was as a result of two factors, (1) low prices for natural gas during the quarter ended March 31, 2009, $3.58 per MMbtu and (b) a dry hole drilled during the quarter ended September 30, 2009, which resulted in costs exceeding the ceiling test.

Wells in Progress - Wells in progress represent the costs associated with wells that have not reached total depth or been completed as of period end. They are classified as wells in progress and withheld from the depletion calculation and the ceiling test. The costs for these wells are then transferred to evaluated property when the wells reach total depth and are cased and the costs become subject to depletion and the ceiling test calculation in future periods.

Sale of Mineral Interests

Uranium One Asset Purchase Agreement ("Uranium One") - Uranium

On April 30, 2007, the Company and certain of its then subsidiary companies, completed the sale of uranium assets, including a uranium mill in Utah and unpatented mining claims in Wyoming, Colorado, Arizona and Utah and certain contractual rights the Company had with a third party for the development of uranium properties. The uranium assets were sold to sxr Uranium One Inc. ("Uranium One,") headquartered in Toronto, Canada with offices in South Africa and Australia (Toronto Stock Exchange and Johannesburg Stock Exchange, "UUU"), and certain of its private subsidiary companies. Uranium One assumed liabilities associated with the uranium assets it acquired, including (but not limited to) those future reclamation liabilities associated with the uranium mill in Utah, and the mining claims.

The Company holds a 4% net profits interest on Rio Tinto's Jackpot uranium property located on Green Mountain in Wyoming. This interest was not included in the sale of uranium assets to Uranium One.

On October 29, 2007, Uranium One purchased a commercial property associated with uranium assets it had previously purchased from the Company, for $2.7 million. Cash proceeds from the sale of the property were $2.6 million. The Company recorded a gain on the sale of assets from the sale of the property of $472,000.

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F. SUPPLEMENTAL FINANCIAL INFORMATION ON OIL AND NATURAL GAS EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES

Capitalized Costs

The following table presents information regarding the Company's net costs incurred in the purchase of proved and unproved properties, and in exploration and development activities:

	(In thousands) Year Ended December 31,	
	2009	2008
Unproved oil and gas properties and wells in progress	$ 5,360	$ 2,968
Proved oil and gas properties	24,595	5,320
Total capitalized costs	$ 29,955	$ 8,288
Accumulated depreciation, depletion and amortization (DD&A)	(3,953)	(382)
Net capitalized costs	$ 26,002	$ 7,906

The Company's DD&A per equivalent BOE was $22.07 in 2009 and $25.20 in 2008.

Undeveloped properties as of December 31, 2009 include costs incurred in the following years:

	(In thousands)			
	Acquisitions	Exploration	Development	Total
2007	$ 1,729	$ --	$ --	$ 1,729
2008	544	--	--	544
2009	1,075	2,012	--	3,087
Total	$ 3,348	$ 2,012	$ --	$ 5,360

Costs Incurred

Costs incurred in oil and natural gas property acquisition, exploration and development activities are summarized below:

	(In thousands) Year Ended December 31,		
	2009	2008	2007
Property acquisition costs:			
Proved	$ --	$ --	$ --
Unproved	560	1,184	2,910

Exploration costs		21,107		4,194		--
Development costs		--		--		--
Total costs incurred	$	21,667	$	5,378	$	2,910

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Results of Operations

Results of operations from oil and natural gas producing activities are presented below:

	(In thousands) Year Ended December 31, 2009	2008	2007
Oil and natural gas revenues	$ 6,844	$ 571	$ --
Less:			
Oil and natural gas operating costs	348	62	--
Depreciation, depletion and amortization	3,571	382	--
Impairment	1,468	--	--
	5,387	444	--
Results of operations from oil and natural gas	$ 1,457	$ 127	$ --

Oil and Natural Gas Reserves (Unaudited)

Proved reserves are estimated quantities of oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are reserves that can reasonably be expected to be recovered through existing wells with existing equipment and operating methods.

Proved oil and natural gas reserve quantities at December 31, 2009 and the related discounted future net cash flows before income taxes are based on the estimates prepared by Cawley, Gillespie & Associates, Inc. and Ryder Scott Company, L.P. The reserve report for the period ended December 31, 2008 was prepared by Ryder Scott Company, L.P. Such estimates have been prepared in accordance with guidelines established by the Securities and Exchange Commission.

The Company's net ownership interests in estimated quantities of proved oil and natural gas reserves and changes in net proved reserves, all of which are located in the continental United States, are summarized below:

December 31, 2009	Oil (BBLS)	Natural Gas or NGL (MCFE)
Beginning of year	29,798	1,000,000
Revisions of previous quantity estimates	(3,747)	423,839
	866,199	710,621

Extensions, discoveries and improved recoveries		
Sales of reserves in place	--	--
Production	(80,461)	(487,978)
End of Year	811,789	1,646,482
Proved developed reserves at end of year	811,789	1,646,482

December 31, 2008	Oil (BBLS)	Gas (MCF)
Beginning of year	--	--
Revisions of previous quantity estimates	--	--
Extensions, discoveries and improved recoveries	32,128	1,073,635
Sales of reserves in place	--	--
Production	(2,330)	(73,635)
End of Year	29,798	1,000,000
Proved developed reserves at end of year	29,798	1,000,000

Standardized Measure (Unaudited)

The standardized measure of discounted future net cash flows relating to the Company's ownership interests in proved oil and natural gas reserves as of year-end is shown below:

	(In thousands) Year Ended December 31,		
	2009	2008	2007
Future cash inflows	$ 51,024	$ 7,112	$ --
Future costs:			
Production	(14,025)	(1,154)	--
Development	(104)	(64)	--
Future income tax expense	(8,273)	(1,993)	--
Future net cash flows	28,622	3,901	--
10% discount factor	(8,638)	(583)	--
Standardized measure of discounted fuure net cash flows	$ 19,984	$ 3,318	$ --

Future cash flows are computed by applying average prices per barrel of oil and per MMbtu of natural gas at the first of each month in the 12-month period prior to the end of the reporting period to year-end quantities of proved oil and natural gas reserves. Average prices used in computing year end 2009 and 2008 future cash flows were $61.18/barrel and $41.41/barrel, respectively, for oil and $3.866/MMbtu and $5.88/MMbtu for natural gas, respectively. Future operating expenses and development costs are computed primarily by the Company's petroleum engineers by estimating the expenditures to be incurred in developing and producing the Company's proved oil and natural gas reserves at the end of the year, based on year end costs and assuming continuation of existing economic conditions.

Future income taxes are based on year-end statutory rates, adjusted for the tax basis of oil and gas properties and available applicable tax assets. A discount factor of 10% was used to reflect the timing of future net cash flows. The standardized measure of discounted future net cash flows is not intended to represent the replacement cost or fair market value of the Company's oil and natural gas properties. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs, and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

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Change in Standardized Measure (Unaudited)

Changes in standardized measure of future net cash flows relating to proved oil and natural gas reserves are summarized below:

	(In thousands) Year Ended December 31, 2009	2008	2007
Balance at beginning of period	$ 3,318	$ --	$ --
Sales of oil and gas, net of production costs	(6,496)	(509)	--
Net change in prices and production costs	297	--	--
Net change in future development costs	--	--	--
Extensions and discoveries	26,721	5,820	--
Revisions of previous quantity estimates	1,586	--	--
Previously estimated development costs incurred	--	--	--
Net change in income taxes	(4,385)	(1,993)	--
Accretion of discount	531	--	--
Changes in production rates, timing and other	(1,588)	--	--
Balance at end of period	$ 19,984	$ 3,318	$ --

Sales of oil and natural gas, net of oil and natural gas operating expenses, are based on historical pretax results. Sales of oil and natural gas properties, extensions and discoveries, purchases of minerals in place and the changes due to revisions in standardized variables are reported on a pretax discounted basis.

G. GEOTHERMAL

During the year ended December 31, 2009, the Company increased its minority interest in Standard Steam Trust, LLC ("SST"), a Denver, Colorado based private geothermal resource acquisition and development company, to $4.3 million from $3.5 million at December 31, 2008. The Company recognized a $1.4 million equity loss during the year ended December 31, 2009. The Company's net investment at December 31, 2009 was $3.0 million. Due to not funding yearend cash call from SST the Company's ownership interest decreased from 25% to 23.8%.

SST is managed by Terra Caliente, LLC ("Terra"), also a private Denver based company, with oversight by an advisory board (USE is one of three members) as to budgets, major expenditures, sale or other disposition of prospects, and similar matters. SST was formed to explore for, acquire and develop geothermal properties to the level where they could be sold to industry partners for the development of electrical generation plants.

H. ENERGY SECTOR HOUSING

Remington Village – Gillette, Wyoming.

During 2008, the Company completed construction of a nine building multifamily apartment complex, with 216 units on 10.15 acres located in Gillette, Wyoming.

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In August 2007, Zions Bank provided secured construction financing (also guaranteed by USE). The amount due under the construction loan was $16.8 million at December 31, 2008. Total cost to buy the land, pay a developer's fee, obtain permits and entitlements, site work and construction, was approximately $24.5 million. During the year ended December 31, 2009 the Company retired the construction loan on the property of $16.8 million from cash reserves.

I. OTHER LIABILITIES AND DEBT

As of December 31, 2009 and 2008, the Company had current and long term liabilities associated with the following funding commitments:

Other Liabilities and Debt:

Other Liabilities

	(In thousands) December 31, 2009	2008
Retainage on construction in progress	$ 10	$ 488
Employee health insurance self funding	--	23
Deferred rent	35	29
Security deposits	150	103
Accrued expenses	29	72
	$ 224	$ 715
Other long term liabilities:		
Accrued retirement costs	$ 762	$ 726

Debt

	December 31, 2009	2008
Short Term Debt		
Construction note - collateralized by property, interest at 2.71%	$ --	$ 16,813
Long Term Debt		

Real estate note - collateralized by property, interest at 6%	$ 800	$ 1,875
Less current portion	(200)	(875)
Totals	$ 600	$ 1,000

In December 2008, the Company and TCM purchased land for $4 million ($2 million in January 2009, $400,000 annually for five years). The Company is responsible for one-half the purchase price. As of December 31, 2009 the Company has paid $1.2 million leaving $800,000 to be paid at the rate of $200,000 per year through 2013.

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At the date of filing of this annual report the Company has a $10,000,000 line of credit from a commercial bank. The line of credit has a variable interest rate (5.5% minimum). The line of credit expires January 31, 2011. As of the date of this report none of the line of credit had been drawn down. The line of credit is collateralized by certain the Company's multifamily housing project, Remington Village, and the Company's aircraft.

J. INCOME TAXES

The income tax provision differs from the amounts computed by applying the statutory federal income tax rate to income from continuing operations before taxes. The reasons for these differences are as follows:

	(In thousands) Year ended December 31,		
	2009	2008	2007
Book income before income taxes	$ (10,457)	$ (4,714)	$ 88,730
Equity income from non consolidated tax sub	--	--	3,551
Add back losses from non consolidated tax subs	--	--	2,010
Prior year true-up and rate change	153	(171)	(265)
Reverse income from discontinued operations	--	(4,907)	--
Tax impact of adjustment resulting from basis study	3,179	--	--
Tax impact of change in asset classification	--	(549)	--
Tax impact of percentage depletion carryover	(355)	--	--
Permanent differences	1,150	1,106	(2,549)
Taxable income before temporary differences	$ (6,330)	$ (9,235)	$ 91,477
Expected Federal and State Tax Benefit (35% for 2008)	--	(3,232)	32,017
Expected Federal Tax Benefit (34% for 2009)	(2,152)	--	-
Expected State Tax Benefit (2% net of federal benefit)	(127)	--	--
Total Expected Tax Benefit	$ (2,279)	$ (3,232)	$ 32,017
Federal deferred income tax expense (benefit)	$ (1,794)	$ 1,319	$ 14,778
Federal current expense (benefit)	(210)	(4,551)	17,239
Total federal income tax expense (benefit)	$ (2,004)	$ (3,232)	$ 32,017
Current state income tax expense net of federal benefit	--	(94)	350
Deferred state income tax expense net of federal benefit	(275)	--	--
Total provision (benefit)	$ (2,279)	$ (3,326)	$ 32,367

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The tax impact of change in asset classification relates to the Company's investment in shares of Sutter Gold Mining, Inc. that it owned at December 31, 2008. When this asset was previously accounted for as a subsidiary, no deferred tax asset for the excess of tax basis over book basis was recognized. As this investment is now being treated as a marketable security, subject to impairment, a deferred tax asset was established in 2008.

In 2009, the Company performed a basis study to reconcile its book basis in depreciable property to its tax basis in such property. As a result of this study the Company determined that its deferred tax liability related to these basis differences was understated. Accordingly, the Company increased the associated deferred tax liability in 2009. This increase is reflected above in the tax impact of adjustment resulting from basis study.

The components of deferred taxes as of December 31, 2009 and 2008 are as follows:

	(In thousands) December 31, 2009	2008
Current deferred tax assets:		
Tax basis in excess of book	$ 349	$ 550
Non-deductible reserves and other	534	43
Total net current deferred tax assets/(liabilities)	$ 883	$ 593
Non-current deferred tax assets:		
Deferred compensation	$ 629	$ 651
Accrued reclamation	76	50
Net operating loss carryover	2,078	--
Alternative Minimum Tax credit carryover	810	--
Charitable contributions carryover	19	--
Percentage depletion carryover	128	--
Total noncurrent deferred tax assets	3,740	701
Non-current deferred tax liabilities:		
Book basis in excess of tax basis	(8,529)	(7,884)
Book basis in excess of tax basis - oil and gas	(2,520)	(1,750)
Accrued reclamation	(36)	(12)
Total deferred tax liabilities	(11,085)	(9,646)

Total net non-current deferred tax assets/(liabilities)	$ (7,345)	$ (8,945)

A valuation allowance for deferred tax assets is required when it is more likely than not that some portion or all of the deferred tax assets will not be realized. No valuation allowance is provided at December 31, 2009 and December 31, 2008 as the Company believes that it is more likely than not that the deferred tax assets will be utilized in future years.

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During the year ended December 31, 2009, net current deferred tax assets increased by $289,000 and net non-current deferred tax liabilities decreased by $1.6 million. The total change in net deferred tax liabilities was a decrease of $1.9 million. This decrease comprised of a deferred income tax benefit $2.1 million, the reduction of other comprehensive income in the amount of $217,000 resulting from the future tax impact of unrealized gain on marketable securities, and an increase to additional paid in capital of $38,000 resulting from the exercise of certain incentive stock options and warrants.

The book basis in excess of tax basis in the schedule above relates primarily to the $7.3 million difference created from the excess of the purchase price over the carrying value of the assets acquired in the purchase of the remaining minority interest of Crested Corp. in 2007.

At December 31, 2009, the Company has a net operating loss carry-forward for federal income tax purposes of $5.1 million which is available to offset future federal taxable income through 2029. In addition, the Company has alternative minimum tax credit carry-forwards of $810,000 which are available to offset future federal income taxes over an indefinite period.

Current taxes receivable at December 31, 2009 is comprised of $353,000 of federal income taxes. At December 31, 2008, current taxes receivable was $5.9 million.

The Company's practice is to recognize interest and/or penalties related to income tax matters in income tax expense. The Company had no accrued interest or penalties at December 31, 2009 or December 31, 2008.

Pursuant to ASC 740-10, the Company identified and evaluated any potential uncertain tax positions. The Company has concluded that there are no uncertain tax positions requiring recognition in the financial statements.

The Internal Revenue Service has audited the Company's and subsidiaries tax returns through the year ended May 31, 2000. The Company's income tax liabilities are settled through fiscal 2000.

K. SEGMENTS AND MAJOR CUSTOMERS

During the years ended December 31, 2009 and December 31, 2008, the Company, for financial reporting purposes, operated in three business segments, the exploration for and sale of oil and gas, rental of multifamily housing units and mining. As of December 31, 2009, no one customer had a majority of the units under contract in the Company's multifamily housing project in Gillette, Wyoming.

During the year ended December 31, 2007, the Company was involved in one reportable business segment, commercial activities which include operations managed by third parties and the sale of real estate lots at the Company's commercial real estate property in southern Utah which has been sold. The Company also received management fees for mineral properties which were not consolidated business segments in prior years but are broken out separately in the attached table for comparison. The Company's operating segments are reflected in the tables below:

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SEGMENT INFORMATION

	(In thousands) For the years ended December 31, 2009	2008	2007
Revenues:			
Real estate	$ 2,768	$ 1,633	$ 934
Oil & gas	6,844	571	--
Other	15	83	240
Total revenues:	9,627	2,287	1,174
Operating expenses:			
Real estate	2,104	1,165	380
Oil and gas	3,919	444	--
Impairment of oil & gas properties	1,468	--	--
Mineral properties	1,636	834	1,093
Total operating expenses:	9,127	2,443	1,473
Interest expense			
Real estate	19	417	--
Oil & gas	--	--	--
Mineral properties	60	--	--
Total interest expense:	79	417	--
Operating gain/(loss)			
Real estate	$ 645	51	554
Oil & gas	1,457	127	--
Mineral properties	(1,681)	(751)	(853)
Operating (loss)	421	(573)	(299)
Other revenues and expenses:	(10,878)	(9,048)	91,033
(Loss)/gain before discontinued operations and income taxes	$ (10,457)	$ (9,621)	$ 90,734
Depreciation, depletion and amortization expense:			

Real estate	$ 1,045	$ 517	$ 41
Oil & gas	3,571	382	--
Mineral properties	54	49	36
Corporate	396	478	361
Total depreciation expense	$ 5,066	$ 1,426	$ 438

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	(In thousands) December 31, 2009	2008
Assets by segment		
Real estate	$ 23,450	$ 30,980
Oil & Gas properties	30,016	8,523
Mineral properties	21,998	24,927
Corporate assets	71,259	78,201
Total assets	$ 146,723	$ 142,631

L. SHAREHOLDERS' EQUITY

During 2009, the Company issued 5,189,655 shares of common stock. Issued shares consist of (a) 5,000,000 shares issued in a public offering during the fourth quarter; (b) 36,583 shares issued for the 2009 ESOP contribution; (c) 80,000 shares issued to officers of the Company pursuant to the 2001 Stock Compensation Plan; (d) 71,088 shares issued as a result of warrants being exercised and (e) 1,984 shares as a result of the exercise of options by an employee of the Company.

Stock Buyback Plan

During the year ended December 31, 2009, the Company completed its $8.0 million stock buyback plan. The Company purchased 706,071 shares for $1.4 million or an average purchase price of $1.98 per share. During prior years the Company purchased 2,388,129 shares at an average cost of $6.6 million or $2.76 per share. The total number of shares purchased under the stock buyback program was 3,094,200 shares for approximately $8.0 million or an average purchase price of $2.59 per share.

Stock Option Plans

The Board of Directors adopted the U.S. Energy Corp. 1989 Stock Option Plan for the benefit of the Company's employees. The Option Plan, as amended and renamed the 1998 Incentive Stock Option Plan ("1998 ISOP"), reserved 3,250,000 shares of the Company's $.01 par value common stock for issuance under the 1998 ISOP. Options which expired without exercise were available for reissue until the 1998 ISOP was replaced by the 2001 ISOP. The last options issued under the 1998 ISOP will expire if not exercised by January 9, 2011 and the 1998 ISOP will be terminated at that date.