US ENERGY CORP
Form 10-K
March 12, 2014

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, 2013

¨ 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:

Title of each class	Name of exchange on which registered
Common Stock, $0.01 par value	NASDAQ Capital Market

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

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

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Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). 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, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ¨ Accelerated filer þ Non-accelerated filer ¨
Smaller reporting company ¨

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, 2013): $52,144,000.

Class	Outstanding at March 11, 2014
Common stock, $.01 par value	27,736,497

Documents incorporated by reference: Certain information required by Items 10, 11, 12, 13, and 14 of Part III is incorporated by reference from portions of the registrant's definitive proxy statement relating to its 2014 annual meeting of stockholders to be filed within 120 days after December 31, 2013.

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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 forward-looking statements in this Annual Report include:

- planned capital expenditures for oil and gas exploration and environmental compliance;
- potential drilling locations and available spacing units, and possible changes in spacing rules;
- 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 Buda formation in South Texas, the Williston Basin in North Dakota, the Eagle Ford shale in South Texas and other areas;
- timing of drilling additional wells and performing other exploration and development projects;
- expected spacing and the number of wells to be drilled with our oil and gas industry partners;
- when "Pooled Payout" or similar thresholds will be reached for the purposes of our agreements with Brigham, Zavanna and other partners;
- expected working and net revenue interests, and costs of wells, relating to the drilling programs with our partners;
- actual decline rates for producing wells in the Buda, Bakken/Three Forks, Eagle Ford and other formations;
- review timing and potential approval of the plan of operations by the U.S. Forest Service in connection with the Mt. Emmons molybdenum project ("Mt. Emmons Project"), the receipt of necessary permits relating to the project, and the expected length of time to permit and develop the project;
- future cash flows, expenses and borrowings;
- pursuit of potential acquisition opportunities;
- our expected financial position;
- 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," "up to," and phrases. Though we believe that the expectations reflected in these statements are reasonable, they involve certain assumptions, risks and uncertainties. Results could differ materially from those anticipated in these statements as a result of numerous factors, including, among others:

For oil and gas:

- our ability to obtain sufficient cash flow from operations, borrowing and/or other sources to fully develop our undeveloped acreage positions;
- volatility in oil and natural gas prices, including declines in oil prices and/or natural gas prices, which would have a negative impact on operating cash flow and could require ceiling test write-downs on our oil and gas assets, and which also could adversely impact the borrowing base available under our credit facility with Wells Fargo Bank (sometimes referred to as the "Credit Facility");

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- 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 return on investment;
- future oil and natural gas production rates, and/or the ultimate recoverability of reserves, falling below estimates;
- the ability to replace oil and natural gas reserves as they deplete from production;
- environmental risks;
- availability of pipeline capacity and other means of transporting crude oil and natural gas production, and related midstream infrastructure and services;
- competition in leasing new acreage and for drilling programs with operating companies, resulting in less favorable terms or fewer opportunities being available;
- higher drilling and completion costs related to competition for drilling and completion services and shortages of labor and materials;
- unanticipated weather events resulting in possible delays of drilling and completions and the interruption of anticipated production streams of hydrocarbons, which could impact expenses and revenues; and
- unanticipated down-hole mechanical problems, which could result in higher than expected drilling and completion expenses and/or the loss of the wellbore or a portion thereof.

For the molybdenum property:

- the ability to obtain permits required to initiate mining and processing operations and the risks associated with adverse rulings concerning these permits;
- 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;
- the ability to fund the capital expenditures required to build the mine and its infrastructure, and the related processing facilities, after all permits and a favorable feasibility study have been received;
- the ability to find a suitable joint venture partner for the project if necessary;
- continued compliance with current environmental regulations and the possibility of new legislation, environmental regulations or permit requirements adverse to the mining industry;
- molybdenum prices and operating costs staying within the parameters established by the feasibility study;
- successfully managing the substantial operating risks attendant to a large scale mining and processing operation; and
- compliance and operating costs associated with the wastewater treatment plant and stormwater management system.

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. 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.

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PART I

Item 1 – Business

Overview

U.S. Energy Corp. ("U.S. Energy", "USE", the "Company", "we" or "us"), is a Wyoming corporation organized in 1966. We an independent energy company focused on the acquisition and development of oil and gas producing properties and other mineral properties in the continental United States. Our oil and gas business is currently focused in South Texas, the Williston Basin in North Dakota and Montana, and Louisiana. However, we do not intend to limit our focus to these geographic areas. We continue to focus on increasing production, reserves, revenues and cash flow from operations while managing our level of debt.

We currently explore for and produce oil and gas through a non-operator business model. However, in the future we may expand our activities to include operations. As a non-operator, we rely on our operating partners to propose, permit, drill, complete and produce oil and gas wells. Before a well is drilled, the operator provides all oil and gas interest owners in the designated well the opportunity to participate in the drilling and completion costs and revenues of the well on a pro-rata basis. Our operating partners also produce, transport, market and account for all oil and gas production.

We are also involved in the exploration for and development of minerals (molybdenum) through our ownership of the Mt. Emmons Project located in west central Colorado, which is a long-term development mining project.

Industry Segments/Principal Products

At December 31, 2013, we have two operating segments: Oil and Gas and Maintenance of Mineral Properties. See Note J to the consolidated financial statements included in this Annual Report for certain financial information by segment.

Office Location and Website

Our principal executive office is 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 (the "SEC") 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 relating to stock ownership of our 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 are not incorporated by reference herein and should not be considered part of this document. In addition, you may read and copy any materials we file with the SEC at the SEC's Public Reference Room, which is located at 100 F Street, NE, Room 1580, Washington, D.C. 20549. Information regarding the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330.

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Business

Oil and Gas

We participate in oil and gas projects primarily as a non-operating working interest owner through exploration and development agreements with various oil and gas exploration and production companies. Our working interest varies by project. These projects may result in numerous wells being drilled over the next three to five years. We are also actively pursuing potential acquisitions of exploration, development and production-stage oil and gas properties or companies.

At December 31, 2013 we had:

- Estimated proved reserves of 3,855,033 BOE (90% oil and 10% natural gas), with a standardized measure value of $104.9 million and a PV10 of $115.1 million.
- At March 5, 2014, our leases covered 143,267 gross and 12,607 net acres.
- 113 gross (16.22 net) producing wells (120 gross (17.29 net) wells at March 5, 2014).
- 1,164 BOE/d average net production for 2013.

PV10 (defined in "Glossary of Oil and Gas Terms") is a non-GAAP measure that is widely used in the oil and gas industry and is considered by institutional investors and professional analysts when comparing companies. However, PV10 data is not an alternative to the standardized measure of discounted future net cash flows, which is calculated under GAAP and includes the effects of income taxes. The following table reconciles PV10 to the standardized measure of discounted future net cash flows as of the dates indicated, which are presented in Note E to the our consolidated financial statements.

	(In thousands) At December 31,		
	2013	2012	2011
Standardized measure of discounted net cash flows	$104,853	$71,017	$62,191
Future income tax expense (discounted)	10,230	5,448	10,346
PV-10	115,083	76,465	72,537

Activities with Operating Partners in Oil and Gas

The Company holds a geographically and geologically diverse portfolio of oil-weighted prospects in varying stages of exploration and development. Prospect stages range from prospect origination, including geologic and geophysical mapping, to leasing, exploration drilling and development. The Company engages in the prospect stages either for its own account or with prospective partners to enlarge our oil and gas lease ownership base.

Each of the operators of our principal prospects has a substantial technical staff. We believe that these arrangements allow us to deliver value to shareholders without having to build the full staff of geologists, engineers and land personnel required to work on diverse projects involving horizontal drilling in North Dakota and South Texas and conventional exploration in Gulf Coast prospects. However, consistent with industry practice with smaller independent oil and gas companies, we also utilize specialized consultants with local expertise as needed.

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The Company currently has oil and gas projects with operating partners in the following areas:

Buda Limestone Formation and Eagle Ford Shale, South Texas Properties

Contango Oil & Gas Company. In 2011, we entered into two participation agreements with Contango Oil & Gas Company ("Contango") to acquire working interests in oil prospects and associated leases located in Zavala and Dimmit Counties, Texas (the "Leona River prospect" and "Booth Tortuga prospect") and working interests in 11 gross (2.98 net) wells producing from the Austin Chalk formation. Under the terms of the agreements, the Company has earned a 30% working interest (and approximate 22.5% net revenue interest) in approximately 11,861 gross acres (3,358.5 net acres). All drilling and leasing occurs on a heads up basis with no carry by the Company. Both prospects are prospective for Eagle Ford, Buda, Pearsall and Georgetown formations. Contango is the operator of the prospects.

On November 13, 2012 the Company acquired a 60% interest in an additional 889.39 gross acres (444 net) with deep oil and gas rights (including the Buda formation) located within the Booth Tortuga prospect acreage for $266,000.

As a result of subsequent acquisitions, our current total acreage in the Leona River and the Booth Tortuga prospects is approximately 15,765 gross acres (4,730 net). Based upon assumed 120 acre spacing units, there is a potential for up to 98 gross and 29.6 net wells in each of the formations should we find commercial quantities of hydrocarbons. Looking forward, the Company continues to seek additional leasing opportunities in this region.

Through the date of this report, we have drilled 7 gross (2.10 net) Buda formation horizontal wells and 3 gross (0.90 net) Eagle Ford formation horizontal wells. Wells in these prospects produced an average of approximately 415 BOE/d net to the Company (76% oil and 24% natural gas and natural gas liquids) during the fourth quarter of 2013.

U.S. Enercorp. On August 5, 2013, under an area of mutual interest election, the Company acquired a 15% working interest in 4,243 gross (636 net) acres (the "Big Wells prospect") from U.S. Enercorp ("Enercorp"), a private oil and gas company based in San Antonio, Texas. This acreage is contiguous to the southwestern portion of the Booth-Tortuga acreage block held with Contango. Under the terms of the election, the leasehold interest is subject to a 25% back-in upon project payout.

Through the date of this report, we have drilled 2 gross (0.30 net) Buda formation horizontal wells in this prospect. During the fourth quarter of 2013, there was one producing well in this prospect that produced approximately 20 BOE/d net to the Company (100% oil).

For further information on the wells drilled in the Buda and Eagle Ford formations in Texas through the date of this Annual Report, see "Item 2 – Properties – Oil and Natural Gas" below.

Williston Basin, North Dakota Properties

Brigham. On August 24, 2009, we entered into a Drilling Participation Agreement (the "DPA") with Brigham Oil & Gas, L.P. ("Brigham"), now a subsidiary of Statoil, 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 the DPA, we earned working interests, derived from Brigham's initial working interests, in fifteen 1,280-acre spacing units in Brigham's Rough Rider project area by participating in the drilling of one initial well in each spacing unit. Accordingly, we have earned the rights to participate in up to 30 gross wells in the Bakken formation and an additional 30 gross wells in the Three Forks formation, for a total of 60 gross wells, based on current spacing rules in

North Dakota.

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If the spacing is ultimately increased to four wells per 1,280 acre spacing unit, the potential number of drilling locations could increase to 120 gross wells. In addition, if stacked horizons within the Three Forks formation are determined to be economical, the total gross potential wells could increase further as operators in this region are now drilling multiple wells to multiple zones within single drilling units.

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 under the terms of the leases obtained by Brigham from third parties, while other leases may have rights to all depths. Working interests earned vary according to Brigham's initial working interest, after-payout provisions and the provisions governing each stage of the program.

Our earn-in rights were staged in three groups of units and were earned upon paying our proportionate share of all drilling and completion costs, or plugging and abandonment costs (if applicable), for all the initial wells (one for each unit) in each group. The number of initial wells (and units in the groups) consists 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 report was filed, see "Item 2 – Properties – Oil and Natural Gas" below. At the date of this report, we have drilled and completed all 15 wells in the initial phase of the DPA and have completed eight additional gross infill wells. These wells produced an average of approximately 385 BOE/d net to the Company (83% oil and 17% natural gas and natural gas liquids) during the fourth quarter of 2013.

Brigham is the operator for all the units covered by the DPA, and is compensated for its 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 2009 and 2010, we earned 65% of Brigham's initial working interest in six initial wells drilled in the 1,280 acre units; our working interest (or "WI") ranges from 61.46% to 29.58% (48.55% to 23.80% net revenue interest (or "NRI")), for an average 49.54% working interest.

We have received production revenues (less property and production taxes) from all six of the initial wells in the First Group equal to our costs on a pooled basis ("Pooled Payout"). Accordingly, our working interest has been reduced to 42.25% of Brigham's initial working interest in the initial wells, and the NRI has decreased to a range of 30.97% to 16.67%, for an average 25.56% NRI. This group of wells produced an average of approximately 89 BOE/d net to the Company (85% oil and 15% natural gas and natural gas liquids) during the fourth quarter of 2013.

By drilling the 6 initial wells in the First Group, we also earned 36% of Brigham's initial working interest in all of the acreage in the applicable unit, which working interest was subsequently reduced by the sale of certain rights to Brigham on December 15, 2011 as noted below. Brigham has no back in rights on any subsequent drilling locations in these units (or in any of the units we earned in the Second and Third Groups). All working interests in each initial well, and all of the subsequent wells, will be subject to proportionate reduction for third party leasehold rights.

Second Group: In 2010, we participated in the drilling and completion of the four wells in the Second Group. Brigham provided us notice that it would be taking 50% of the initial working interest available to them, and we elected to take the remaining 50% of the initial working interest available to Brigham. The four wells were all producing in 2013; our working interests range from 48.03% to 21.02% (NRIs range from 38.24% to 16.29%).

By drilling the 4 initial wells in the Second Group, we also earned working interest rights in all the acreage in these four units. For future wells drilled in these units, we will hold 36% of Brigham's initial

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working interest (without back in rights), subject to proportionate reduction for third party leasehold rights, which working interests were subsequently reduced by the sale of certain rights to Brigham on December 15, 2011 as noted below. After Pooled Payout on the Second Group of four wells, we will assign to Brigham 35% of our working interest in the initial wells in each spacing unit, and the NRI will decrease to a range of 24.86% to 10.59%. We anticipate that Pooled Payout for the Second Group will be reached in the fourth quarter of 2014. This group of wells produced an average of approximately 74 BOE/d net to the Company (83% oil and 17% natural gas and natural gas liquids) during the fourth quarter of 2013.

Third Group: On January 11, 2010, Brigham provided us notice that it would be taking 50% of the working interest available to it in the Third Group. In accordance with the DPA, we elected to take the remaining 50% of the working interest available to Brigham. All five wells in this group were drilled and producing at December 31, 2013. Working (and net revenue) interests range from 42.40% (34.23% NRI) to 24.91% (19.69% NRI).

By drilling the 5 wells in the Third Group, we also earned 36% of Brigham's initial working interest in all the acreage in the units in the Third Group (which will not be subject to back in rights), proportionately reduced for third party leasehold rights, which working interest was subsequently reduced by the sale of certain rights to Brigham on December 15, 2011 as noted below. After payout on a per initial well basis ("Unpooled Payout"), we will assign 27.7% of our working interest in each initial well to Brigham, resulting in NRIs of 24.89% to 14.32%. One well reached Unpooled Payout in 2013. We expect the remaining four initial wells to reach Unpooled Payout between early 2016 and late 2020.

Effective December 15, 2011, the Company sold an undivided 75% of its undeveloped acres in the Rough Rider prospect to Brigham for $13.7 million. Under the terms of the agreement, the Company retained the remaining 25% of its interest in the undeveloped acreage and its original working interest in its 20 developed wells in the Rough Rider prospect. After the sale, our working interest in the undeveloped acreage in the Rough Rider prospect ranges from 3.41% to 9.90%.

From August 24, 2009 to December 31, 2013, we have drilled and completed 21 gross (6.25 net) Bakken formation wells and 2 gross (0.22 net) Three Forks formation well under the DPA. Three gross wells (0.07 net) are in progress as of the date of this report. At this time, no additional drilling activity is scheduled in 2014. Statoil's drilling plans beyond 2014 are not known at this time.

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 was drilled, we have the right to elect not to participate in the drilling or completion in subsequent wells proposed to be drilled in a unit. If the Company 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.

Zavanna, LLC. In December 2010, we signed two agreements with Zavanna, a private oil and gas company based in Denver, Colorado, and other parties. The Company paid $11.0 million in cash to acquire 35% of Zavanna's working interests in oil and gas leases covering approximately 6,050 acres net to Zavanna's interest in McKenzie County, North Dakota which interest was subsequently reduced by the sale to GeoResources, Inc. and Yuma Exploration and Production Company, Inc. in January 2012 as noted below. Approximately 1,650 net acres are currently subject to the agreements.

The acquired acreage is in two prospects – the Yellowstone Prospect and the SE HR Prospect. We expect this program will result in 27 gross 1,280 acre spacing units with the potential for 108 gross Bakken and 108 gross Three Forks wells, based on an assumed four wells per formation in each spacing

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unit. In addition, if stacked horizons within the Three Forks formation are determined to be economical, the total gross potential wells could increase further as operators in this region are now drilling multiple wells to multiple zones within single drilling units.

Our interests in all the acreage in both prospects is subject to reduction by a 30% reversionary working interest under each prospect upon expiration of the "Project Payout Period" or "Project Payout," as those terms are defined in the agreements, whichever occurs first. Project Payout will occur when we have received proceeds from the sale of production (or from the sale of all or part of the acreage to third parties) equal to 130% of the $11.0 million paid on execution of the agreements, plus all drilling and completion costs (including dry hole costs) and surface gathering facilities for all wells drilled on the acreage (and on any additional acreage acquired in the two Areas of Mutual Interest contemplated by the agreements). This acreage is referred to collectively as the "Project Payout Properties." The Project Payout Period for the Yellowstone Project is from the spud date of the initial well drilled in the prospect to July 15, 2014 and the Project Payout Period for the SE HR Prospect is from the spud date of the initial well drilled in the prospect to March 31, 2014.

If Project Payout does not occur within the Project Payout Period, the reduction due to operation of the reversionary working interest will take effect on all acreage other than the Project Payout Properties (i.e., that acreage on which wells have not commenced drilling, including all infill locations in drilling units where the Project Payout Properties are located). After expiration of the Project Payout Period, all costs and expenses related to the Project Payout Properties will continue to be included in the Project Payout calculation until Project Payout occurs. Based on the current economic assumptions used in the December 31, 2013 reserve report, we do not expect these projects to achieve Project Payout.

On January 24, 2012 (but effective as of December 1, 2011), the Company sold an undivided 75% of its undeveloped acreage in the SE HR Prospect and the Yellowstone Prospect to GeoResources, Inc. (56.25%) and Yuma Exploration and Production Company, Inc. (18.75%) for a total of $16.7 million. Under the terms of the agreement, the Company retained the remaining 25% of its interest in the undeveloped acreage and its original working interest in its 10 developed wells in the SE HR and Yellowstone prospects. Our working interest in the remaining locations is approximately 8.75% and net revenue interests in new wells after the sale are in the range of 6.7375% to 7.0%, proportionately reduced depending on Zavanna's actual working interest percentages.

As of December 31, 2013, we have interests in twenty-seven gross 1,280 acre spacing units in the Yellowstone and SEHR prospects with Zavanna. We have drilled and completed 31 gross (3.00 net) Bakken formation wells in these prospects and 4 gross (0.27 net) Three Forks formation wells, including 12 gross (0.16 net) wells operated by Emerald Oil Inc., 2 gross (0.13 net) wells operated by Murex Petroleum, 2 gross (0.04 net) wells operated by Kodiak Oil & Gas, Inc. and 1 gross (0.01 net) well operated by Slawson Exploration Company, Inc. Zavanna operates the remaining wells. These wells produced an average of approximately 276 BOE/d net to the Company (91% oil and 9% natural gas and natural gas liquids) during the fourth quarter of 2013.

Bakken/Three Forks Asset Package Acquisition. On September 21, 2012, but effective July 1, 2012, we acquired interests in 27 producing Bakken and Three Forks formation wells and related acreage in McKenzie, Williams and Mountrail Counties of North Dakota for $2.3 million after adjusting for related revenue and operating expenses from the effective date through September 21, 2012. Under the terms of the agreement, we acquired working interests in 23 drilling units ranging from less than 1% to approximately 5%, with an average working interest of 1.67%. All acreage is currently held by production and produced approximately 80 BOE/d net to the Company (88% oil and 12% natural gas and natural gas liquids) during the fourth quarter of 2013.

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For further information on the wells drilled in North Dakota through the date of this Annual Report, see "Item 2 – Properties – Oil and Natural Gas" below.

Louisiana Properties

Texas Petroleum Investment Company. The Company has an interest in one producing well with Texas Petroleum Investment Company ("TPIC") with a 25% WI (17.63% NRI). During the fourth quarter of 2013, average daily production from this well was approximately 4 BOE/d net to the Company (86% oil and 14% natural gas).

PetroQuest Energy, L.L.C. The Company has an interest in one natural gas and oil producing well with PetroQuest Energy, L.L.C. in coastal Louisiana, with a working interest of 17.0% (12.75% NRI). During the fourth quarter of 2013, average daily production from this well was approximately 83 BOE/d net to the Company (100% natural gas).

Other Texas Properties

Southern Resources Company. Our agreement with Southern Resources Company ("Southern") covers a 13.5% working interest (9.86% NRI) in 1,282 gross (173 net) acres in Hardin County, Texas. The Company earned a working interest in all the acreage by participating in the initial test well and paying $135,000 in seismic, land acquisition and legal costs. The Company agreed to carry the seller in an 18.75% working interest to the casing point decision ("CPD") in the initial test well, and a 12.5% carried working interest in the second test well to the CPD. Subsequent wells will be paid for proportionally to all parties' working interests. Mueller Exploration, Inc. ("Mueller") operates all of the wells. As of December 31, 2013 we had 1 gross (0.14 net) producing well in this project. No drilling is currently scheduled on these properties in 2014. During the fourth quarter of 2013, average daily net production from this well was approximately 1 BOE/d (48% oil and 52% natural gas and natural gas liquids).

Woodbine Acquisition. In May 2012, we entered into a participation agreement with Mueller to participate in the Woodbine Sub-Clarksville 7 Project located in Anderson and Cherokee Counties, Texas. Under the terms of the agreement, we acquired a 26.5% initial working interest (19.6% net revenue interest) in approximately 6,766 gross (1,274 net) acres for $1.7 million. The promoted amount covered our portion of the costs for land, geological and geophysical work, as well as all dry hole costs for an initial test well in each of the seven prospects. Upon payout of our initial well costs in each unit, our interest will be reduced to a 19.8% working interest (14.7% net revenue interest). Future infill drilling will be on a heads up basis, and our interest will be a 19.8% working interest (14.7% net revenue interest). All seven initial wells were drilled in 2012 and deemed to be non-productive. Two of the wells had non-commercial quantities of oil and gas, indicating potential for up-dip exploration. One additional gross (0.20 net) well was drilled in 2013 and determined to be non-productive. No additional drilling is scheduled at this time.

For further information on the wells drilled in Texas and Louisiana through the date of this Annual Report, see "Item 2 – Properties – Oil and Natural Gas" below.

Daniels County, Montana Acreage

In 2010 through 2012, the Company acquired a working interest in approximately 30,332 gross (18,939 net) mineral acres of undeveloped leasehold interests in Daniels County, Montana for approximately $1.2 million. This acreage is believed to have conventional and horizontal Bakken and Three Forks resource potential.

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On June 8, 2012, we sold an undivided 87.5% of this acreage to Greehey & Company Ltd. ("Greehey") for $3.7 million. Under the terms of the agreement, we retained a 12.5% working interest in the acreage and reserved overriding royalty interests ("ORRI") in leases we owned that had in excess of 81% NRI. Greehey also committed to drill a vertical test well to depths sufficient to core the Bakken and Three Forks formations on or before December 31, 2015. We delivered an 80% NRI to the purchaser and a 1% ORRI to Energy Investments, Inc. ("EII"), a land broker, in connection with the sale. We also paid EEI a commission equal to 10% of the cash consideration paid by Greehey.

Forward Plan

In 2014 and beyond, the Company intends to seek additional opportunities in the oil and natural gas sector, including but not limited to further acquisition of assets, participation with current and new industry partners in their exploration and development projects, acquisition of operating companies, and the purchase and exploration of new acreage positions.

Activities other than Oil and Gas

Molybdenum

The Company re-acquired the Mt. Emmons Project located near Crested Butte, Colorado on February 28, 2006. The Mt. Emmons Project includes a total of 160 fee acres, 25 patented and approximately 1,345 unpatented mining and mill site claims, which together approximate 9,853 acres, or over 15 square miles of claims and fee lands. For further information, see "Item 2 – Properties – Molybdenum - Mt. Emmons Project" below.

Renewable Energy — Geothermal

At December 31, 2013 we owned a 19.54% interest in Standard Steam Trust ("SST"), a geothermal limited liability company. Our investment in SST does not obligate us to fund any future cash calls, but if we elect not to fund cash calls, we will suffer dilution. We did not participate in any cash calls in 2011, 2012 or 2013, which diluted our ownership. In December 2013, we recorded an impairment charge of $2.2 million to write off the carrying amount of the investment in SST at December 31, 2013 to zero.

Assets Held for Sale

The Company's audited consolidated financial statements and notes thereto included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2012 presented approximately $17.1 million in book value of assets held for sale, consisting of $15.2 million related to Remington Village and $1.9 million related to a corporate aircraft and related facilities. These assets were sold during 2013.

Remington Village Sale

On September 11, 2013, the Company, through its wholly owned subsidiary Remington Village LLC, completed the sale of the Remington Village Apartment Complex in Gillette, Wyoming ("Remington Village") to an affiliate of the Miller Frishman Group, LLC for $15.0 million. The $9.5 million balance on the commercial note due on Remington Village was paid in full at closing. After deduction of payment of the note, commission and other closing costs, the net proceeds to the Company were approximately $5.0 million, which have been allocated to the Company's oil and gas business, reduction of debt and general corporate purposes.

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Corporate Aircraft and Related Facilities Sale

On January 10, 2013, the Company sold its corporate aircraft for $1.9 million and related facilities for $767,000. The proceeds were allocated to our oil and gas business and general corporate purposes.

Item 1A - Risk Factors

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

Risks Involving Our Business

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 risk, and thus a significant risk of loss of initial investment that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The cost and timing 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;
- inability to obtain required permits from State and Federal agencies;
- inability to obtain, or limitations on, easements from land owners;
- uncertainty regarding our operating partners drilling schedules;
- high pressure or irregularities in geologic formations;
- equipment failures;
- title problems;
- fires, explosions, blowouts, cratering, pollution, spills and other environmental risks or accidents;
- changes in government regulations and issuance of local drilling restrictions or moratoria;
- adverse weather;
- 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 that impair or prevent production. We may participate in wells that are or become unproductive or, though productive, do not produce in economic quantities.

In addition, initial 24-hour or other limited-duration production rates announced regarding our oil and gas properties are not necessarily indicative of future production rates.

Dry holes and other unsuccessful or uneconomic exploration, exploitation and development activities can adversely affect our cash flow, profitability and financial condition, and can adversely affect our reserves. As a non-operator, we have limited ability to control the manner in which drilling and other exploration and development activities on our properties are conducted, which may increase these risks.

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Our business may be impacted by adverse commodity prices.

In the past three years, oil prices have ranged from a high of $113.39 per barrel to a low of $75.40 per barrel. Global markets, in reaction to general economic conditions and perceived impacts of future global supply, have caused large fluctuations in price, and significant future price swings are likely. Natural gas prices have also been volatile, reaching a ten year high during December 2005 on the Henry Hub of $15.39 per MMbtu, and a ten year low during April 2012 of $1.82 per MMbtu. Declines in the prices we receive for our oil and natural gas production can adversely affect many aspects of our business, including our financial condition, revenues, results of operations, cash flows, liquidity, reserves, rate of growth and the carrying value of our oil and natural gas properties, all of which depend primarily or in part upon those prices. Declines in the prices we receive for our oil and natural gas also can adversely affect our ability to finance capital expenditures, make acquisitions, raise capital and satisfy our financial obligations. In addition, declines in prices can reduce the amount of oil and natural gas that we can produce economically and, as a result, adversely affect the quantity and present value of our proved reserves. Among other things, a reduction in our reserves can limit the capital available to us, as the maximum amount of available borrowing under our Credit Facility is, and the availability of other sources of capital likely will be, based to a significant degree on the estimated quantity and value of our reserves.

Mineral prices also change significantly over time. Molybdenum prices have fluctuated significantly, with 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, 2013 was $9.75 per pound, compared to $11.57 per pound at year end 2012. Price improvement in 2014 will be dependent on continued demand, but demand could weaken if industrial consumption sags due to economic constraints in key global markets. Lower molybdenum prices would adversely affect the feasibility of developing the Mt. Emmons Project.

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

Generally, crude oil produced from the Bakken formation in North Dakota is high quality (36 to 44 degrees API, which is comparable to West Texas Intermediate Crude). However, due to takeaway constraints, our realized oil prices in the Williston Basin generally have been from $8.00 to $10.00 less per barrel than prices for other areas in the United States, and recently as much as $24.00 less per barrel. This discount, or differential, may widen in the future, which would reduce the price we receive for our production.

Drilling and completion costs for the wells we drill in the Williston Basin are comparable to or higher than other areas where there is no price differential. As a result of this reverse leverage effect, a significant, prolonged downturn in oil prices on a national basis could result in a ceiling limitation write-down of the oil and gas properties we hold. Such a price downturn also could reduce the cash flow from our Williston Basin properties and adversely impact our ability to participate fully in drilling with Brigham, Zavanna and other operators. Our production in other areas could also be affected by adverse changes in differentials. In addition, changes in differentials could make it more difficult for us to effectively hedge our exposure to changes in commodity prices.

We may require funding in addition to working capital during 2014.

We were able to maintain adequate working capital in 2013 primarily through borrowing under our Credit Facility and cash flow from operations. Working capital at December 31, 2013 was $6.0 million, an amount that is sufficient to continue substantial exploration and development work on our oil and gas properties, but may not be enough to take full advantage of the opportunities we now have or to be in position to pursue new opportunities. In 2014, we have budgeted $22.2 million for work on existing oil and gas programs and $8.0 million for acquisitions.

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Our exploration and development agreements contain customary industry non-consent provisions. Pursuant to these provisions, if a well is proposed to be drilled or completed but a working interest owner doesn't participate, the resulting revenues (which otherwise would go to the non-participant) flow to the participants until they receive from 150% to 300% of the capital they provided to cover the non-participant's share. In order to be in position to avoid non-consent penalties and to make opportunistic investments in new assets, we will continue to evaluate various options to obtain additional capital, including borrowings under our Credit Facility, sales of one or more producing or non-producing oil and gas assets and/or the issuance of equity.

The oil and gas and minerals businesses present the opportunity for significant returns on investment, but achievement of such returns is subject to high risk. As examples:

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

- We are paying the annual costs (approximately $1.7 million) to operate and maintain the water treatment plant and stormwater management system at the Mt. Emmons Project, and these costs could increase in the future.

These types of events could require a reassessment of priorities and therefore potential re-allocations of existing capital and could also mandate obtaining new capital. There can be no assurance that we will be able to complete any financing transaction on acceptable terms. For example, our ability to borrow under our Credit Facility may be limited if we are unable, or run a significant risk of becoming unable, to comply with the financial covenants that we are required to satisfy under the agreement. In addition, the borrowing base under the agreement is subject to redetermination periodically and from time to time at the lenders' discretion. Borrowing base reductions may occur as a result of unfavorable changes in commodity prices, asset sales, performance issues or other events. In addition to reducing the capital available to finance our operations, a reduction in the borrowing base could cause us to be required to repay amounts outstanding under the Credit Facility in excess of the reduced borrowing base, and the funds necessary to do so may not be available at that time. Other sources of external debt or equity financing may not be available when needed on acceptable terms or at all, especially during periods in which financial market conditions are unfavorable. Also, the issuance of equity would be dilutive to existing shareholders.

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

The oil and natural gas business is very competitive. We compete with many public and private exploration and development companies in finding investment opportunities. We also compete with oil and gas operators in acquiring acreage positions. Our principal competitors are small to mid-size companies with in-house petroleum exploration and drilling expertise. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. They also 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.

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Successful exploitation of the Buda formation, the Williston Basin (Bakken and Three Forks shales) and the Eagle Ford shale is subject to risks related to horizontal drilling and completion techniques.

Operations in the Buda formation and the Bakken, Three Forks and Eagle Ford shales in many cases involve utilizing the latest drilling and completion techniques in an effort 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 (as applicable to the formation) and being able to run tools and other equipment consistently through the horizontal well bore.

For wells that are hydraulically fractured, completion risks include, but are not limited to, being able to fracture stimulate the planned number of frac stages, 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 sufficient period of time.

Currently, the typical cost for drilling and completing a horizontal well is estimated at approximately $4.0 million for wells targeting the Buda formation, between $8.9 million and $11.2 million for wells in the Williston Basin, and $7.5 million for wells in the Eagle Ford, in each case on a gross basis. Costs for any individual well will vary due to a variety of factors. These wells are significantly more expensive than a typical onshore shallow conventional well. Accordingly, unsuccessful exploration or development activity affecting even a small number of wells could have a significant impact on our results of operations. Costs other than drilling and completion costs can also be significant for Williston Basin, Eagle Ford and other wells. For example, we incurred approximately $3.1 million in workover costs relating to a single Williston Basin well in 2011, and these costs substantially exceeded our estimates.

If our access to oil and gas markets is restricted, it could negatively impact our production and revenues. Securing access to takeaway capacity may be particularly difficult in less developed areas of the Williston Basin.

Market conditions or limited availability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines, rail transportation and processing facilities owned and operated by third parties. In particular, access to adequate gathering systems or pipeline or rail 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 as those in other areas.

As of the date of this report, all of the wells we have drilled in the Williston Basin have produced oil and natural gas (generally at an initial ratio of about 85% oil and 15% gas). Oil sales generally commence immediately after completion work is finished, but natural gas is flared (burned off) until the well can be hooked up to a transmission line. Installation of a gathering system can take from 90 to 120 days, or longer, depending on well location, weather conditions, and availability of service providers. As of the date of this report, all but one of our Williston Basin wells is selling gas.

Continued drilling in the Williston Basin and South Texas has placed additional demands on the capacity of the various gathering and intrastate or interstate transportation pipelines or rail tankers and other midstream facilities available in these areas, and increased production from us and others could

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exceed available capacity in some areas from time to time. If this occurs, it will be necessary for new rail takeaway lines, pipelines, gathering systems and/or other types of infrastructure to be built. Certain pipeline or rail projects that are planned for the Williston Basin and other areas may not occur. In such event, we might have to sell our production for significantly lower prices or shut in our wells until a pipeline connection or rail capacity is available. In the case of natural gas, we may have to flare the gas we produce or shut the well in.

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

We may not be able to participate in all or even a substantial portion of the many locations we have potentially available through our agreements with our partners. 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, applicable spacing rules and other factors.

Lower oil and natural gas prices may cause us to record ceiling test 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 (a charge often referred to as a "ceiling test write-down"). The risk of a ceiling test write-down increases when oil and gas prices are depressed, if we have substantial downward revisions in estimated proved reserves or if we drill unproductive wells.

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.

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Full cost pool capitalized costs are amortized over the life of production of proven properties. Capitalized costs at December 31, 2013, 2012 and 2011, which were not included in the amortized cost pool, were $7.5 million, $9.2 million and $20.0 million, respectively. These costs consist of wells in progress, costs for seismic analysis of potential drilling locations, and 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, 2013 and 2012, 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, 2013, we used $96.78 per barrel for oil and $3.67 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%.

During the first quarter of 2013, capital costs for oil and gas properties exceeded the ceiling test limit and we recorded a ceiling test write-down of $5.8 million primarily due to a decline in the price of oil, additional capitalized well costs and changes in production. We recorded a similar write-down of $5.2 million in 2012. We may be required to recognize additional ceiling test 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.

We do not currently operate our drilling locations. 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 operate or at the current time expect to be the operator of any of the prospects we hold with industry partners. As a non-operator, our ability to exercise influence over the operations of the drilling programs is limited. In the usual case in the oil and gas industry, new work is proposed by the operator and often is approved by most of the non-operating parties. If the work is approved by the holders of a majority of the working interests, but we disagree with the proposal and do not (or are unable to) participate, we will forfeit our share of revenues from the well until the participants receive 150% to 300% of their investment. In some cases, we could lose all of our interest in the well. We would avoid a penalty of this kind only if a majority of the working interest owners agree with us and the proposal does not proceed.

The success and timing of our drilling and development activities on properties operated by others depend upon a number of factors outside of our control, including:

- the nature and timing of the operator's drilling and other activities;
- the timing and amount of required capital expenditures;
- the operator's geological and engineering expertise and financial resources;
- the approval of other participants in drilling wells; and
- the operator's selection of suitable technology.

The fact that we do not operate our prospects with industry partners makes it more difficult for us to predict future production, cash flows and liquidity needs. Our ability to grow our production and reserves depends on decisions by our partners to drill wells in which we have an interest, and they may elect to reduce or suspend the drilling of those wells.

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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 provide estimates of the quantities of hydrocarbons that can be economically recovered from proved properties, utilizing current commodity prices and taking into account expected capital and other expenditures. These reports also provide estimates of the future net present value of the reserves, which we use for internal planning purposes and for testing the carrying value of the properties on our balance sheet.

The reserve data included in this report represent estimates only. Estimating quantities of, and future cash flows from, 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, 2013, 53% of our estimated proved reserves were producing, 3% were proved developed non-producing and 44% were proved undeveloped. Estimation of proved undeveloped reserves and proved developed non-producing reserves is almost always based on analogy to existing wells, volumetric analysis or probabilistic methods, 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 and proved undeveloped 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 and standardized measure estimates are based on costs as of the date of the estimates and assume fixed commodity prices. Actual future prices and costs may be materially higher or lower than the prices and costs used in the estimate.

Further, the effect of derivative instruments is not reflected in these assumed prices; we have three such instruments in place at December 31, 2013. Also, the use of a 10% discount factor to calculate PV10 and standardized measure values may not necessarily represent the most appropriate discount factor given actual interest rates and risks to which our business or the oil and natural gas industry in general are subject.

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

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

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

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

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

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

Additionally, the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, among other things, imposes restrictions on the use and trading of certain derivatives, including energy derivatives. The nature and scope of those restrictions will be determined in significant part through regulations that are in the process of being implemented by the SEC, the Commodities Futures Trading Commission and other regulators. If, as a result of the Dodd-Frank Act or its implementing regulations, capital or margin requirements or other limitations relating to our commodity derivative activities are imposed, this could have an adverse effect on our ability to implement our hedging strategy. In particular, a requirement to post cash collateral in connection with our derivative positions, which are currently collateralized on a non-cash basis by our oil and natural gas properties and other assets, would likely make it impracticable to implement our current hedging strategy. In addition, requirements and limitations imposed on our derivative counterparties could increase the costs of pursuing our hedging strategy.

Our acreage must be drilled before lease expiration, generally within three to five years, in order to hold the acreage by production. In the highly competitive market for acreage, failure to drill sufficient wells in order to hold acreage will result in a substantial lease renewal cost, or if renewal is not feasible, the loss of our lease and prospective drilling opportunities.

Unless production is established within the spacing units covering the undeveloped acres on which some of our potential drilling locations are identified, the leases for such acreage will expire. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. In addition, on certain portions of our acreage, third-party leases could become immediately effective if our leases expire. As such, our actual drilling activities may materially differ from our current expectations, which could adversely affect our business.

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Our producing properties are primarily located in the Williston Basin and South Texas, making us vulnerable to risks associated with having operations concentrated in these geographic areas.

Because our operations are geographically concentrated in the Williston Basin and South Texas (93% of our production in the fourth quarter of 2013 was from these areas), the success and profitability of our operations may be disproportionally exposed to the effect of regional events. These include, among others, regulatory issues, natural disasters and fluctuations in the prices of crude oil and natural gas produced from wells in the region and other regional supply and demand factors, including gathering, pipeline and other transportation capacity constraints, available rigs, equipment, oil field services, supplies, labor and infrastructure capacity. Any of these events has the potential to cause producing wells to be shut-in, delay operations and growth plans, decrease cash flows, increase operating and capital costs and prevent development of lease inventory before expiration. In addition, our operations in the Williston Basin may be adversely affected by seasonal weather and lease stipulations designed to protect wildlife, which can intensify competition for services, infrastructure and equipment during months when drilling is possible and may result in periodic shortages. Any of these risks could have a material adverse effect on our financial condition and results of operations.

Our acquisition activities may not be successful.

As part of our growth strategy, we have made and may continue to make acquisitions. However, suitable acquisition candidates may not continue to be available on terms and conditions we find acceptable, and acquisitions pose substantial risks to our business, financial condition and results of operations. In pursuing acquisitions, we compete with other companies, many of which have greater financial and other resources than we do. The following are some of the risks associated with acquisitions, including any completed or future acquisitions:

- acquired properties may not produce revenues, reserves, earnings or cash flow at anticipated levels, or at all;
- we may assume liabilities that were not disclosed to us or that exceed our estimates;
- we may be unable to integrate acquisitions successfully and realize anticipated economic, operational and other benefits in a timely manner, which could result in substantial costs and delays or other operational, technical or financial problems; and
- acquisitions could disrupt our ongoing business, distract management, divert resources and make it difficult to maintain our current business standards, controls and procedures.

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

Typically, operators obtain a preliminary title opinion prior to drilling. We rely on our operating partners to provide us with ownership of the interests we pay for. To date, our operators have generally provided preliminary title opinions prior to drilling. 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 a productive well because the operator (and therefore the Company) would not own the interest.

Insurance may be insufficient to cover future liabilities.

Our business is focused in two areas, each of which presents potential liability exposure: oil and gas exploration and development and permitting and limited exploration of the Mt. Emmons molybdenum property. We also have potential exposure to general liability and property damage associated with the

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ownership of other corporate assets. In the past, we relied primarily on the operators of our oil and gas properties to obtain and maintain liability insurance for our working interest in our oil and gas properties. In some cases, we may continue to rely on those operators' insurance coverage policies depending on the coverage. However, since June 2011, we have established our own insurance policies for our oil and gas operations that are broader in scope and coverage and are in our control. We also maintain insurance policies for liabilities associated with and damage to general corporate assets.

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

We would be liable for claims in excess of coverage and for any deductible provided for in the relevant policy. If uncovered liabilities are substantial, payment could adversely impact the Company's cash on hand, resulting in possible curtailment of operations. Moreover, some liabilities are not insurable at a reasonable cost or at all.

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

Oil and gas exploration, development and production activities are subject to certain federal, state and local laws and regulations relating to a variety of issues, including 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, well construction, the spacing of wells, unitization and pooling of properties, habitat and endangered species protection, reclamation and remediation, restrictions on drilling activities in restricted areas, emissions into the environment, management of drilling wastes, water discharges, chemical disclosures 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 any future changes. The adoption or enforcement of stricter regulations, if enacted, could have a significant impact on our operating costs.

Our business activities in mining are also regulated by government agencies. Among other things, permits are required to explore for minerals, operate mines and build and operate processing facilities. 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 new or modified regulations, we may decide not to move forward with the project.

In addition, we must comply with numerous environmental laws and regulations with respect to our activities, including the National Environmental Policy Act, or NEPA, the Clean Air Act, the Clean Water Act, and the Resource Conservation and Recovery Act, or RCRA. Other laws impose reclamation obligations on abandoned mining properties, in addition to or in conjunction with federal statutes.

Under these laws and regulations, we could be liable for personal injuries, property and natural resource damages, releases or discharges of hazardous materials, well reclamation costs, oil spill clean-up costs, other remediation and clean-up costs, plugging and abandonment costs, governmental sanctions, and other environmental damages. Some environmental laws, such as the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), impose joint and several and strict liability. Strict liability means liability without fault such that in some situations we could be exposed to liability for clean-up costs and other damages as a result of conduct that was lawful at the time it occurred or

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otherwise without negligence on our part or for the conduct of third parties. These third parties may include prior operators of properties we have acquired, operators of properties in which we have an interest and parties that provide transportation services for us. If exposed to joint and several liabilities, we could be responsible for more than our share of a particular clean-up, reclamation or other obligation, and potentially for the entire obligation, even where other parties were involved in the activity giving rise to the liability.

Federal, state and local legislation and regulations relating to hydraulic fracturing could result in increased costs, additional drilling and operating restrictions or delays in the production of natural gas and crude oil, and could prohibit hydraulic fracturing activities.

Many of our activities involve the use of hydraulic fracturing, which is a process that creates a fracture extending from the well bore in a rock formation to enable oil or natural gas to move more easily through the rock pores to a production well. Fractures are typically created through the injection of water and chemicals into the rock formation.

Proposals have been introduced in the U.S. Congress to regulate hydraulic fracturing operations and related injection of fracturing fluids and propping agents used by the oil and natural gas industry in fracturing fluids under the Safe Drinking Water Act (“SDWA”), and to require the disclosure of chemicals used in the hydraulic fracturing process under the SDWA, the Emergency Planning and Community Right-to-Know Act (“EPCRA”), or other laws. Sponsors of these bills, which have been subject to various proceedings in the legislative process, including in the House Energy and Commerce Committee and the Senate Environmental and Public Works Committee, have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies and otherwise cause adverse environmental impacts. In March 2011, the Environmental Protection Agency (“EPA”) announced its intention to conduct a comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on water quality and public health. EPA issued an initial report about the study in December 2012. The initial report described the focus of the continuing study but did not include any data concerning EPA’s efforts to date, nor did it draw any conclusions about the safety of hydraulic fracturing. A draft report including data and conclusions is expected in 2014.

EPA also has begun a Toxic Substances Control Act (“TSCA”) rulemaking which will collect expansive information on the chemicals used in hydraulic fracturing fluid, as well as other health-related data, from chemical manufacturers and processors. Concurrently, the White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices.

EPA also finalized major new Clean Air Act (“CAA”) standards (New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants) applicable to hydraulically fractured natural gas wells in August 2012. The standards will require, among other things, use of reduced emission completions, or green completions, to reduce volatile organic compound emissions during well completions as well as new controls applicable to a wide variety of storage tanks and other equipment, including compressors, controllers, and dehydrators. While most key provisions in the new CAA standards are not effective until 2015 and EPA currently is re-considering parts of the rule, the rules associated with such standards are substantial and will likely increase future costs of our operations and will require us to make modifications to our operations and install new equipment.

EPA has also issued permitting guidance under the SDWA for the underground injection of liquids from hydraulically fractured (and other) wells where diesel is used. This recently-issued guidance may create duplicative requirements, further slow down the permitting process in certain areas, increase the costs of operations, and result in expanded regulation of hydraulic fracturing activities by EPA depending on how it is implemented. Certain other federal agencies are analyzing, or have been requested to review, environmental issues associated with hydraulic fracturing. Most notably, the U.S. Department of the

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Interior, through the Bureau of Land Management ("BLM"), is currently conducting a rulemaking that will require, among other things, disclosure of chemicals and more stringent well integrity measures associated with hydraulic fracturing operations on public land. BLM has not indicated when it will issue a final rule.

Currently, hydraulic fracturing is regulated primarily at the state level through permitting and other compliance requirements. For example, North Dakota requires disclosure of information concerning the chemicals used in hydraulic fracturing fluids and imposes certain well construction and testing requirements. In addition, Montana has enacted regulations requiring operators to disclose information about hydraulic fracturing fluids on a well-by-well basis. Further, operators must generally obtain approval from the state before hydraulic fracturing occurs and submit a report after the work is performed. Montana also requires specific construction and testing requirements for wells that will be hydraulically fractured. Other states in which we conduct operations may implement similar or more onerous requirements. Certain state governments have adopted or are considering adopting laws and regulations that impose or could impose, among other requirements, stringent permitting or air emission control requirements, disclosure, wastewater disposal, baseline sampling, well construction and well location requirements on hydraulic fracturing operations or otherwise seek to ban underground injection of fracturing wastewater or fracturing activities altogether. At the local level, some municipalities and local governments have adopted or are considering similar actions.

In addition, lawsuits have been filed against unrelated third parties in a number of states alleging contamination of drinking water by hydraulic fracturing. Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition to natural gas and crude oil production activities using hydraulic fracturing techniques. Additional legislation, litigation, regulation, or moratoria could also lead to operational delays or lead us to incur increased operating costs in the production of crude oil and natural gas, including from the development of our shale plays, or could make it more difficult to perform hydraulic fracturing or other drilling activities. If these legislative, regulatory, litigation, and other initiatives cause a material decrease in the drilling of new wells and in related servicing activities, our profitability could be materially impacted.

Certain federal income tax deductions currently available with respect to crude oil and natural gas and exploration and development may be eliminated as a result of future legislation.

President Obama has made proposals that would, if enacted into law, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could defer or eliminate certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition and results of operations.

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

Climate change has emerged as an important topic in public policy debate. It is a complex issue, with some scientific research suggesting that rising global temperatures are the result of an increase in greenhouse gases ("GHGs"). Products produced by the oil and natural gas exploration and production industry are a source of certain GHGs, namely carbon dioxide and methane, and future restrictions on the combustion of fossil fuels or the venting of natural gas could have a significant impact on our future operations. EPA has issued a notice of finding and determination that emissions of carbon dioxide,

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methane and other GHGs present an endangerment to human health and the environment, which has allowed the EPA to begin regulating emissions of GHGs under existing provisions of the Clean Air Act. The EPA has begun to implement GHG-related reporting and permitting rules. Similarly, the U.S. Congress has considered, and may in the future consider, "cap and trade" legislation that would establish an economy-wide cap on emissions of GHGs in the United States and would require most sources of GHG emissions to obtain GHG emission "allowances" corresponding to their annual emissions of GHGs. Similarly, President Obama has indicated that climate change and GHG regulation is a significant priority for his second term. The President issued a Climate Action Plan in June 2013 that, among other things, calls for a reduction in methane emissions from the oil and gas sector. In November 2013, the President released an Executive Order charging various federal agencies, including EPA, with devising and pursuing strategies to improve the country's preparedness and resilience to climate change. In part through these executive actions, the direct regulation of methane emissions from the oil and gas sector continues to be a focus of regulation. 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 our production. For example, 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. Also, 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 regulatory changes and/or perceived negative impacts on the climate from GHGs could result in lower world-wide consumption of, and prices for, crude oil.

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 can be adversely affected by seasonal weather conditions. In the Williston Basin, drilling and other oil and natural gas activities sometimes cannot be conducted as effectively during the winter months, and this can materially increase our operating and capital costs. Gulf Coast operations are also subject to the risk of adverse weather events, including hurricanes.

Shortages of equipment, services and qualified personnel could reduce our cash flow and adversely affect results of operations.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices and activity levels in new regions, causing periodic shortages. These problems can be particularly severe in certain regions such as the Williston Basin and Texas. During periods of high oil and gas prices, the demand for drilling rigs and equipment has increased along with increased activity levels, and this may result in shortages of equipment. In addition, there is currently a shortage of hydraulic fracturing capacity in many of the areas in which we participate. Higher oil and natural gas prices generally stimulate increased demand for equipment and services and subsequently often result in increased prices for drilling rigs, crews and associated supplies, oilfield equipment and services, and personnel in exploration, production and midstream operations. These types of shortages and subsequent price increases could significantly decrease our profit margin, cash flow and operating results and/or restrict or delay our ability to drill those wells and conduct those activities that we currently have planned and budgeted, causing us to miss our forecasts and projections.

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We do not have a feasibility study relating to Mt. Emmons.

We have not yet completed a feasibility study on the Mt. 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 of 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 deposit contains 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).

The timing and cost of obtaining a feasibility study for the Mt. Emmons property cannot be predicted. However, when such a study is obtained, it may not support our internal valuations of the property, and additionally may not be sufficient to attract new partners or investment capital.

The exploration and future development of our Mt. Emmons Project is highly speculative, involves substantial expenditures, and may be non-productive.

Mineral exploration and development, including the exploration and development of our Mt. Emmons Project, involves a high degree of risk. Exploration projects are frequently unsuccessful and few prospects that are explored are ultimately developed into producing mines. We cannot assure you that our exploration or development efforts at Mt. Emmons will be successful. Substantial expenditures are required to determine if the project has economically mineable mineralization, and our ability to fund these expenditures will be driven substantially by the market price for molybdenum. It could take several years to obtain the necessary governmental approvals and permits to establish proven and probable mineral reserves and to develop and construct mining and processing facilities. Because of these uncertainties, it cannot be assumed that our efforts at Mt. Emmons will result in the discovery of economic mineral reserves or the development of the project into a producing mine. Similarly, other attempts to create value from the Mt. Emmons Project, including a potential land exchange transaction, may not be successful.

Development of the Mt. Emmons Project is subject to numerous environmental and permitting risks.

The Mt. Emmons Project is located on fee property within the boundary of U.S. Forest Service ("USFS") land. Although mining of the mineral resource would occur on fee property, associated ancillary activities will occur on USFS land. The Company submitted a full mine plan of operations in part to satisfy the requirements of the conditional water rights decree on October 10, 2012. Under the procedures mandated by the National Environmental Protection Act ("NEPA"), the USFS is expected to prepare an environmental analysis in the form of an environmental impact statement to evaluate the predicted environmental and socio-economic impacts of the proposed mine plan. The NEPA process provides for public review and comment of the proposed plan.

The USFS is the lead regulatory agency in the NEPA process, and coordinates with the various federal and state agencies in the review and approval of the mine plan of operations. Various Colorado state agencies will have primary jurisdiction over certain areas. For example, enforcement of the Clean Water Act in Colorado is delegated to the Colorado Department of Public Health and Environment. A water discharge permit under the Colorado Discharge Permit System ("CDPS") is required before the USFS can approve the plan of operations. We currently have CDPS permits for the discharge from the water treatment plant and for stormwater discharges associated with the Mt. Emmons Project, but this project is not related to the proposed mining activities.

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

Obtaining and maintaining the various permits for the mining operations at the Mt. Emmons Project will be complex, time-consuming, and expensive, and is subject to ongoing litigation. 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 control, or changes in agency policy and federal and state laws, could further affect the successful permitting of the mine operations and the costs of complying with environmental permits and related requirements. The timing, cost, and ultimate success of our future development efforts and mining operations cannot be predicted.

We depend on key personnel.

Our employees have experience in dealing with the acquisition of and financing of oil and gas as well as mineral properties, but we have a limited technical staff. From time to time we rely on third party consultants for professional engineering, geophysical and geological advice in oil and gas matters. 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 oil and gas and minerals industry.

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 common stock, warrants and convertible debt to investors in private placements and public offerings. These transactions caused dilution to existing shareholders. Also, from time to time, we issue options and warrants to employees, directors and third parties as incentives, with exercise prices equal to the market price at the date of issuance. Exercise of options and warrants would result in dilution to existing shareholders. Future issuances of equity securities, or securities convertible into equity securities, would also have a dilutive effect on existing shareholders. In addition, the perception that such issuances may occur could adversely affect the market price of our common stock.

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. Accordingly, stockholders must look solely to increases in the price of our common stock to realize a gain on their investment, and this may not occur.

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We could implement take-over defense mechanisms that could discourage some advantageous transactions.

Although our shareholder rights plan expired in 2011, certain provisions of our governing documents and applicable law could have anti-takeover effects. For example, we are subject to a number of provisions of the Wyoming Management Stability Act, an anti-takeover statute, and have a classified or “staggered” board. We could implement additional anti-takeover defenses in the future. These existing or future defenses could prevent or discourage a potential transaction in which shareholders would receive a takeover price in excess of then-current market values, even if a majority of the shareholders support such a transaction.

Our stock price likely will continue to be volatile.

Our stock is traded on the Nasdaq Capital Market. In the two years ended December 31, 2013, the stock has traded as high as $3.83 per share and as low as $1.47 per share. The principal factors which have contributed and/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 stock trading on any given day;
- fluctuations in our financial operating results;
- industry trends;
- legislative and regulatory changes; and
- global economic uncertainty.

The stock market has recently experienced significant price and volume fluctuations, as have some commodity prices. These fluctuations have particularly affected the market prices of securities of oil and gas companies like ours. These market fluctuations could adversely affect the market price of our stock.

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

Our reserve estimates as of December 31, 2013, 2012 and 2011 are based on reserve reports prepared by Cawley, Gillespie & Associates, Inc., or CGA, Ryder Scott Company, L.P., or Ryder Scott, and Netherland, Sewell & Associates, Inc., or NSAI. CGA, Ryder Scott and NSAI are nationally recognized independent petroleum engineering firms. CGA is a Texas Registered Engineering Firm (F-693). Our primary contact at CGA is Mr. W. Todd Brooker, Senior Vice President. Mr. Brooker is a State of Texas Licensed Professional Engineer (License # 83462). Ryder Scott is a Texas Registered Engineering Firm (F-1580). Our primary contact at Ryder Scott is Mr. James F. Latham, Senior Vice President. Mr. Latham is a State of Texas Licensed Professional Engineer (License #49586). NSAI is a Texas Registered Engineering Firm (F-2699). Our primary contact at NSAI is Mr. Richard B. Talley, Jr., Vice

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President. Mr. Talley is a State of Texas Licensed Professional Engineer (License #102425). CGA prepared the estimates for all properties in 2013 and 2012 and for our North Dakota properties in 2011. NSAI prepared the estimates for our Austin Chalk and Eagle Ford properties in Texas in 2011. Ryder Scott prepared the estimates related to our Gulf Coast Basin, including Louisiana and Texas, properties in 2011. The reserve estimates were based upon the review (by the relevant contracted engineering firm(s)) of the production histories and other geological, economic, ownership and engineering data, as provided by us and the corresponding operators to them. A copy of CGA's report is filed as an exhibit to this report.

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

	December 31,		
	2013	2012	2011
Net proved reserves			
Oil (Bbls)			
Developed	1,875,528	1,770,659	1,884,068
Undeveloped	1,584,187	842,984	853,930
Total	3,459,715	2,613,643	2,737,998
Natural gas (Mcf)			
Developed	1,701,282	1,420,295	1,973,453
Undeveloped	670,628	377,791	760,595
Total	2,371,910	1,798,086	2,734,048
Plant Products (Bbls)			
Developed	--	--	1,688
Undeveloped	--	--	--
Total	--	--	1,688
Total proved reserves (BOE)	3,855,033	2,913,324	3,195,361

(1) Reserve estimates are based on average prices per barrel of oil and per MMbtu of natural gas at the first day of each month in the 12-month period prior to the end of the reporting period. Reserve estimates as of December 31, 2013 are based on prices of $96.78 per barrel of oil and $3.67 per MMbtu of natural gas, in each case adjusted for regional price differentials and other factors.

As of December 31, 2013, our proved reserves totaled 3,855,033 BOE (56% developed and 44% undeveloped), comprised of 3,459,715 Bbls of oil (90% of the total) and 2,371,910 Mcf of natural gas (10% of the total). 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". A variety of methodologies are used to determine our proved reserve estimates. The principal methodologies employed are reservoir simulation, decline curve analysis, volumetrics, material balance, advance production type curve matching, petrophysics/log analysis and analogy. Some combination of these methods is used to determine reserve estimates in substantially all of our fields.

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Proved Undeveloped Reserves

As of December 31, 2013, we had 1,695,958 BOE (93% oil and 7% natural gas) of proved undeveloped reserves, which is an increase of 790,008 BOE, or 87%, compared with 905,950 BOE of proved undeveloped reserves at December 31, 2012. This increase was primarily due to successful drilling in the Buda formation in South Texas. We invested approximately $7.0 million to convert 361,936 BOE of proved undeveloped reserves to proved developed reserves in 2013. The following table details the changes in the quantity of proved undeveloped reserves during the year ended December 31, 2013:

December 31, 2013	BOE
Beginning of year	905,950
Conversion to Proved Developed Producing	(361,936)
Revisions of previous quantity estimates	(29,038)
Extensions, discoveries and improved recoveries	1,180,982
Purchase of reserves in place	--
Sales of reserves in place	--
End of year	1,695,958

As of December 31, 2013, we have no proved undeveloped reserves that have been on the books in excess of five years and we have recorded no material proved undeveloped locations that were more than one direct offset from an existing producing well. Additionally, no proved undeveloped reserves are scheduled for development beyond five years of initial booking. As of December 31, 2013, estimated future development costs relating to proved undeveloped reserves are projected to be approximately $37.7 million over the next five years.

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 report. The information set forth below is not necessarily indicative of future results.

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	December 31, 2013	2012	2011
Production Volume			
Oil (Bbls)	343,719	373,531	300,325
Natural gas (Mcf)	408,352	347,810	736,261
Natural gas liquids (Bbls)	13,155	13,203	19,325
BOE	424,933	444,702	442,360
Daily Average Production Volume			
Oil (Bbls/d)	942	1,021	823
Natural gas (Mcf/d)	1,119	950	2,017
Natural gas Liquids (Bbls/d)	36	36	53
BOE/d	1,164	1,215	1,212
Oil Price per Bbl Produced			
Realized Price	$90.81	$82.38	$87.80
Natural Gas Price per Mcf Produced			
Realized Price	$4.66	$3.25	$4.85
Natural Gas Liquids Price per Bbl Produced			
Realized Price	$40.42	$47.84	$52.88
Average Sale Price per BOE (1)	$79.18	$73.16	$69.98
Expense per BOE			
Production costs (2)	$16.78	$16.42	$19.10
Depletion, depreciation and amortization	$32.06	$33.49	$31.64

(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.

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The following table provides a regional summary of our production for the years ended December 31, 2013, 2012 and 2011:

	December 31,		
	2013	2012	2011
Williston Basin			
Oil (Bbls)	280,789	352,372	271,939
Natural gas (Mcf)	145,586	124,077	129,635
Natural gas liquids (Bbls)	9,654	12,113	--
BOE	314,707	385,165	293,545
Gulf Coast / South Texas			
Oil (Bbls)	1,610	3,120	16,081
Natural gas (Mcf)	190,311	194,888	590,982
Natural gas liquids (Bbls)	124	477	19,325
BOE	33,453	36,078	133,903
Eagle Ford / Buda			
Oil (Bbls)	53,603	10,283	4,290
Natural gas (Mcf)	69,022	27,351	8,479
Natural gas liquids (Bbls)	2,788	437	--
BOE	67,895	15,279	5,703
Austin Chalk			
Oil (Bbls)	7,717	7,756	8,015
Natural gas (Mcf)	3,433	1,494	7,165
Natural gas liquids (Bbls)	589	176	--
BOE	8,878	8,181	9,209
Total			
Oil (Bbls)	343,719	373,531	300,325
Natural gas (Mcf)	408,352	347,810	736,261
Natural gas liquids (Bbls)	13,155	13,203	19,325
BOE	424,933	444,702	442,360

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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, 2011 through December 31, 2013. The number of gross wells is the total number of wells we participated in, regardless of our ownership interest in the wells.

	Years Ended December 31,					
	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Productive	15.00	1.33	11.00	1.76	1.00	0.25
Non-productive	--	--	--	--	--	--
	15.00	1.33	11.00	1.76	1.00	0.25
Exploratory:						
Productive	15.00	0.84	8.00	1.12	12.00	2.98
Non-productive	1.00	0.20	7.00	1.39	4.00	0.80
	16.00	1.04	15.00	2.51	16.00	3.78
Total	31.00	2.37	26.00	4.27	17.00	4.03

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, 2013. 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	112.00	16.05	14.33%
Natural Gas	1.00	0.17	17.00%
Total (1)	113.00	16.22	14.35%

(1) The average working interest for the ninety-one Williston Basin wells producing at December 31, 2013 is 11.46%; the remaining twenty-two wells (in Texas and Louisiana) have an average working interest of 26.28%.

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The following map reflects where our oil and gas properties are generally located:

Acreage

The following table summarizes our estimated developed and undeveloped leasehold acreage as of December 31, 2013.

	Developed		Undeveloped		Total	
AREA	Gross	Net	Gross	Net	Gross	Net
Williston Basin						
Rough Rider Prospect (1)	19,200	1,175	--	--	19,200	1,175
Yellowstone and SEHR Prospects (1)	35,840	1,650	--	--	35,840	1,650
ASEN North Dakota Acquisition (1)	29,440	400	--	--	29,440	400
Wolverine Prospect, Daniels County, MT	--	--	29,788	2,334	29,788	2,334
East Texas and Louisiana	1,824	289	6,766	1,274	8,590	1,563
Buda/Eagle Ford/Austin Chalk						
Leona River Prospect	4,965	1,490	--	--	4,965	1,490
Booth Tortuga Prospect	10,800	3,240	400	120	11,200	3,360
Big Wells Prospect	120	18	4,123	618	4,243	636
TOTAL	102,189	8,261	41,077	4,346	143,267	12,607

(1) The total gross acres for this area is calculated by multiplying the number of drilling units we participate in by 1,280 acres.

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As a non-operator, we are subject to lease expiration if any operator does not commence the development of operations within the agreed terms of our leases. All of our leases for undeveloped acreage summarized in the table below will expire at the end of their respective primary terms, unless we renew the existing leases, establish commercial production from the acreage or some other “savings clause” is exercised. In addition, our leases typically provide that the lease does not expire at the end of the primary term if drilling operations have been commenced. While we generally expect to test or establish production from most of our acreage prior to expiration of the applicable lease terms, there is no assurance that we can do so. The approximate expiration of our gross and net acres which are subject to expiration between 2014 and 2017 are set forth below:

	Williston Basin, North Dakota and Montana		Buda / Eagle Ford / Austin Chalk, Texas		East Texas and Louisiana		TOTAL	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
2014	16,388	1,336	4,523	738	6,766	1,274	27,677	3,348
2015	9,690	450	--	--	--	--	9,690	450
2016	3,320	97	--	--	--	--	3,320	97
2017	80	1	--	--	--	--	80	1
	29,478	1,884	4,523	738	6,766	1,274	40,767	3,896

Present Activities

As of March 5, 2014, we were in the process of drilling 3 gross (0.06 net) wells and 7 gross (0.29 net) wells were drilled and waiting on completion.

Molybdenum – Mt. Emmons Project

The Mt. Emmons Project is located near Crested Butte, Colorado and includes a total of 160 fee acres, 25 patented and approximately 1,345 unpatented mining and mill site claims, which together approximate 9,853 acres, or over 15 square miles of claims and fee lands. The Mt. Emmons Project is located in Gunnison County, Colorado. The property is accessed by vehicle traffic on Gunnison County Road 12.

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We own both surface and mineral rights at the Mt. Emmons Project in fee pursuant to mineral patents issued by the federal government. 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 to the BLM; the total amount paid for mining and millsite claim maintenance fees in 2013 was $193,000.

The breakdown of the property is as follows:

	Acres	Claims
Patented Claims / Fee Land	365	25
Unpatented Claims	5,923	664
Mill Site Claims	3,405	681
Fee Property	160	n/a
Total	9,853	1,370

Title

Approximately 25 of the Mt. Emmons Project 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 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 Mt. Emmons Project mining claims are valid and in good standing.

History of the Mt. Emmons Project

We leased various patented and unpatented mining claims on the Mt. Emmons Project to Amax, Inc. (“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 Mt. Emmons Project to treat water flowing from the historic 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. Phelps Dodge ("PD") then acquired the Mt. Emmons Project in 1999 through its acquisition of Cyprus Amax. Thereafter, PD acquired additional conditional water rights and patents to certain mineral claims. The Company re-acquired the Mt. Emmons Project on February 28, 2006. The property was returned to us by PD in accordance with a 1987 Amended Royalty Deed and Agreement between us and Amax.

The exploration work conducted in the late 1970s by Amax as discussed in Cyprus Amax's Patent Claim Application to the BLM dated December 23, 1992, defined the initial mineralized material at the Mt. 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 are also a number of existing mine adits located on the property. Historic work completed by Amax 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.

In its 1992 patent application, Cyprus Amax stated that the size and grade of the Mt. 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 was 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 analysis set forth in the letter 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.

We note that the statements made by the predecessor owners of the Mt. Emmons Project regarding "recoverable" minerals and "mineralized material" were based on costs, permitting requirements and commodity prices then prevailing. We believe these estimates to be relevant, but they should not be relied upon. Substantial additional exploration and drilling efforts and a full feasibility study will be required, using current estimated 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 by the Company and Thompson Creek Metals Company USA ("Thompson Creek" or "TCM") for $4 million ($2 million in January 2009, $400,000 annually for five years). On January 21, 2014, the Company purchased TCM's interest in the property for $1.2 million.

In October 2012, the Company acquired 17 additional mill site claims, totaling approximately 85 additional acres.

Geology

The sedimentary sequence in the Mt. Emmons area spans from the late Cretaceous to the early Tertiary periods. 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 Mt. Emmons, but may be seen in valley bottoms a few miles to the north, south, and east. All of the Mancos Formation

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encountered in the vicinity of the Mt. 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 Mt. 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 Mt. Emmons. Capping Mt. 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 Mt. 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 Mt. Emmons stock has intruded the Mancos and Mesaverde sediments, strongly metamorphosing both formations to hornfels up to 1,500 feet outward from the igneous body. Sedimentary rocks on Mt. 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 Mt. Emmons molybdenum mineralized zone and the associated alteration zones. Hydrothermal alteration associated with the Mt. 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 Mt. Emmons stock.

Water Treatment Plant; Site Facilities

PD’s 2006 re-conveyance of the property to the Company 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 Public Health and Environment (“CDPHE”). We are responsible for all operating and maintenance costs. Also, as described in the Mine Plan of Operations submitted to the USFS, the Company currently plans on using the mine water treatment plant in the milling operations for the Mt. Emmons Project. We are also currently investigating reclamation strategies that may be used to reduce the quantity of discharge water and improve the quality of treated water and stormwater subject to permit-related requirements.

The water treatment plant was constructed by Amax in 1981 (at a cost of approximately $15 million) to treat mine discharge water from the historic Keystone Mine which produced lead and zinc. A certified water treatment plant operations contractor with five licensed and/or trained employees operates the water treatment plant on a continuous basis, treating water discharged from the historic Keystone Mine. The plant utilizes a standard lime pH adjustment to precipitate heavy metals from the water. Mine water is then filtered and discharged to Coal Creek in accordance with the requirements of the CDPS permit for the plant, and solids are dewatered and mixed with cement for proper disposal in accordance with state and federal law. The existing permit will be renewed in 2014. Modifications and improvements to the treatment system were tested and implemented in 2012 and 2013. We also maintain coverage under the CDPS General Permit for Stormwater Discharges associated with the Metal Mining Industry. This permit

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provides authorization to discharge stormwater from the Mt. Emmons Project subject to the general requirements of the permit itself, which are applicable to all active and inactive metal mining operations in Colorado, and a site-specific stormwater management plan. Permit modifications in 2012 required ongoing monitoring of stormwater discharges and the reporting of monitoring results to the CDPHE. In 2013, we commenced a more comprehensive study of natural and human-induced conditions in the region that may be affecting water quality in Coal Creek. Those efforts will continue in 2014, and the results may support a future application to the CDPHE to modify Coal Creek water quality standards based on site-specific ambient conditions.

Historical Capital Expenditures by Prior Owners, and Related Information

Amax reportedly spent approximately $150 million in exploration and related activities on the Mt. Emmons Project, which included construction of the water treatment plant. Since the Company reacquired the property in 2006, an additional $22.7 million has been spent on the development of the property. In addition, our annual operating cost for the water treatment plant is approximately $1.8 million. The total costs associated with future drilling and the development of the project has not yet been determined.

We are using grid electric power to operate the water treatment plant and other facilities from the local electric utility serving Gunnison County.

Activities in 2010 - 2013 and Plans for 2014

On October 10, 2012, the Company submitted a full mine plan of operations to the U.S. Forest Service (“USFS”) to satisfy the requirements of the conditional water rights decree. During 2014, we will be submitting a new Mine Plan of Operations (MPO) to the USFS related to hydrology data collection from areas of proposed activity at our proposed new mine site. This new MPO would include field work such as borings, test pits and ground water monitoring wells. The USFS will have to review the new MPO and follow the NEPA process before approval will be given. Field work will commence following approval by the USFS and providing weather allows access to the field sites.

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.

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.

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Annual Metal Week Dealer Oxide mean prices for molybdenum averaged $10.40 in 2013, compared to $12.81 in 2012.

Real Estate

Remington Village - Gillette, Wyoming

Remington Village Sale

We previously owned Remington Village, a nine-building multifamily apartment complex with 216 units on 10.015 acres in Gillette, Wyoming. On September 11, 2013, the Company, through its wholly owned subsidiary Remington Village LLC, completed the sale of Remington Village to an affiliate of the Miller Frishman Group, LLC for $15.0 million. The $9.5 million balance on the commercial note due on Remington Village was paid in full at closing. After deduction of payment of the note, commission and other closing costs, the net proceeds to the Company were approximately $5.0 million, which have been allocated to the Company's oil and gas business, reduction of debt and general corporate purposes.

Fremont County, Wyoming

U.S. Energy owns a 14-acre tract in Riverton, Wyoming, with a two-story 30,400 square foot office building. The first floor is rented to non-affiliates and government agencies; the second floor is occupied by the Company.

In addition, we own three city lots covering 13.84 acres adjacent to our corporate office building and two unrelated vacant lots covering approximately 10.23 acres in Fremont County, Wyoming. We intend to sell these properties without development. However, there can be no assurance that sales of any of these properties will be completed on the terms, or in the time frame, we expect or at all.

Corporate Aircraft and Related Facilities Sale

On January 10, 2013, the Company sold its corporate aircraft for $1.9 million and related facilities for $767,000. The proceeds were allocated to our oil and gas business and general corporate purposes.

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 the time 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 any potential future receipt of funds from any of these contingencies is not known.

Royalty on Uranium Claims

We hold a 4% net profits interest on certain 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.

Marketing, Major Customers and Delivery Commitments

Markets for oil and natural gas are volatile and are subject to wide fluctuations depending on numerous factors beyond our control, including seasonality, economic conditions, foreign imports, political conditions in other energy producing countries, OPEC market actions, and domestic government regulations and policies. All of our production is marketed by our industry partners for our benefit and is sold to competing buyers, including large oil refining companies and independent marketers. Substantially all of our production is sold pursuant to agreements with pricing based on prevailing commodity prices, subject to adjustment for regional differentials and similar factors. We had no material delivery commitments as of December 31, 2013.

Competition

The oil and natural gas business is highly competitive in the search for and acquisition of additional reserves and in the sale of oil and natural gas. Our competitors principally consist of major and intermediate sized integrated oil and natural gas companies, independent oil and natural gas companies and individual producers and operators. In particular, we compete for property acquisitions and our operating partners compete for the equipment and labor required to operate and develop our properties. Our competitors may be able to pay more for properties and may be able to define, evaluate, bid for and purchase a greater number of properties than we can. Ultimately, our future success will depend on our ability to develop or acquire additional reserves at costs that allow us to remain competitive.

Environmental

Like the oil and natural gas industry in general, our properties are subject to extensive and changing federal, state and local laws and regulations designed to protect and preserve natural resources and the environment. The recent trend in environmental legislation and regulation is generally toward stricter standards, and this trend is likely to continue. These laws and regulations often require a permit or other authorization before construction or drilling commences and for certain other activities; limit or prohibit access, seismic acquisition, construction, drilling and other activities on certain lands; impose substantial liabilities for pollution resulting from our operations; and require the reclamation of certain lands. Federal, state and local laws and regulations regarding the discharge of materials into the environment or otherwise relating to the protection of the environment include NEPA, the Clean Air Act, the Federal Water Pollution Control Act of 1972 (the "Clean Water Act"), the Colorado Water Quality Control Act, the Oil

Pollution Act of 1990, RCRA, and CERCLA. Regulations, including permit requirements, applicable to our operations have been changed frequently in the past and, in general, these changes have imposed more stringent requirements that increase operating costs and/or require capital expenditures to remain in compliance. Failure to comply with these requirements can result in civil and/or criminal penalties and liability for non-compliance, clean-up costs and other environmental damages. It is also possible that unanticipated developments or changes in the law could require us to make environmental expenditures significantly greater than those we currently expect. See “Federal, state and local legislation and regulations relating to hydraulic fracturing could result in increased costs, additional drilling and operating restrictions or delays in the production of crude oil and natural gas, and could prohibit hydraulic fracturing activities” and “Climate change legislation or regulations restricting emissions of ‘greenhouse gases’ could result in increased operating costs and reduced demand for the crude oil and natural gas that we produce” in “Risk Factors” for a discussion of certain regulatory developments that may have an adverse effect on us.

With respect to proposed mining operations at the Mt. Emmons Project, Colorado’s mine permitting statute, the Abandoned Mine Reclamation Act, and industrial development and siting laws and regulations, may also affect the project. We believe we are in compliance in all material respects with existing environmental regulations. In October 2012, the CDPHE modified the CDPS stormwater permit for the site to require additional monitoring to determine whether or not stormwater discharges from the site are in full compliance with permit requirements. The CDPHE may impose more stringent requirements when the permit is renewed in 2014 (the prior permit expired as of August 31, 2013, and the CDPHE administratively extended the permit, including all existing discharge limitations, pending renewal). In addition, we will continue monitoring activities at and surrounding the Mt. Emmons Project in 2014 in an effort to identify sources of heavy metals loading to Coal Creek. The results of these studies may be used to revise water quality standards and permit limits in a way that better ensures the feasibility of discharge permit compliance long term. We are also currently investigating reclamation strategies that may be used to reduce the quantity of discharge water and improve the quality of treated water and stormwater subject to permit-related requirements. 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 Mt. Emmons Project, see the consolidated financial statements included in Part II of this Annual Report.

We may generate wastes, including “solid” wastes and “hazardous” wastes that are subject to regulation under RCRA and comparable state statutes, although certain mining and oil and natural gas exploration and production wastes currently are exempt from regulation as hazardous wastes under RCRA. EPA has limited the disposal options for certain wastes that are designated as hazardous wastes. Moreover, certain wastes generated by our mining and oil and natural gas operations that currently are exempt from regulation as hazardous wastes may in the future be designated as hazardous wastes and, as a result, become subject to more rigorous and costly management, disposal and remediation requirements.

Although all of our currently producing oil and gas properties are operated by third parties, the activities on the properties are still subject to environmental protection regulations that affect us. 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 for which we could have liability. Based on the current regulatory environment in those states where we have oil and natural gas investments and rules and regulations currently in effect, we do not currently expect to make any material capital expenditures for environmental control facilities.

Oil and gas operations also are subject to various federal, state and local regulations governing oil and natural gas production and state limits on allowable rates of production by well. These regulations may affect the amount of oil and natural gas available for sale, the availability of adequate pipeline and other

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regulated transportation and processing facilities, and other matters. State and federal regulations generally are intended to prevent waste of oil and natural gas, protect groundwater resources, protect rights to produce oil and natural gas 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 to change existing requirements or to add new requirements. Regulatory changes can adversely impact the permitting and exploration and development of mineral and oil and gas properties including the availability of capital.

In addition, oil and gas and mineral projects are subject to extensive permitting requirements. Failure to timely obtain required permits to start operations at a project could cause delay and/or the failure of the project resulting in a potential write-off of the investments made.

Insurance

The following summarizes the material aspects of the Company's insurance coverage:

General

We have liability insurance coverage in amounts we deem sufficient for our business operations, consisting of property loss insurance on all major assets equal to the approximate replacement value of the assets and additional liability and control of well insurance for our oil and gas drilling programs. Payment of substantial liabilities in excess of coverage could require diversion of internal capital away from regular business, which could result in curtailment of projected future operations.

Mt. Emmons Project

The Company is responsible for all costs to operate the water treatment plant at the Mt. Emmons Project. We maintain an insurance policy for our benefit in the amounts of $1 million per event, $2 million aggregate general liability, $1 million automobile liability, $10 million environmental impairment liability, and $10 million excess liability (an upper limit on the coverage other than environmental).

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

Employees

As of December 31, 2013, we had 15 full-time employees.

Item 3 – Legal Proceedings

Material legal proceedings pending at December 31, 2013 and developments in those proceedings from that date to the date of this Annual Report are summarized below.

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Water Rights Litigation –Mt. Emmons Project

On July 25, 2008, we filed an Application for Finding of Reasonable Diligence with the Colorado Water Court ("Water Diligence Application") concerning the conditional water rights associated with the Mt. Emmons Project (Case No. 2008CW81). The conditional water decree ("Decree") required the Company to file its proposed plan of operations and associated permits with the Forest Service and BLM within six years of entry of the Decree, or within six years of the final determination of the pending patent application, whichever occurred later. The BLM issued the mineral patents on April 2, 2004. Although the issuance of the patents was appealed, on April 30, 2007, the United States Supreme Court made a final determination (by denial of certiorari) upholding BLM's issuance of the mineral patents. The Company filed a plan of operations on March 31, 2010.

On August 11, 2010, High Country Citizen's Alliance, Crested Butte Land Trust and Star Mountain Ranch Association, Inc. ("Opposers") filed a motion for summary judgment alleging that the plan of operations did not comply with the United States Forest Service ("USFS") regulations and did not satisfy certain "reality check" limitations contained in the Decree. On September 24, 2010, we filed a response to the motion for summary judgment responding that the plan of operations complied with USFS and BLM regulations and satisfied the reality check limitations. The U.S. Department of Justice also filed a response on behalf of the USFS and BLM asserting that the Court cannot second guess the USFS's determination that the plan of operations satisfied USFS and BLM regulations.

On November 24, 2010 the District Court Judge denied the Opposers's motion for summary judgment and held that Company had until April 30, 2013 to comply with the reality check provision of the Decree, which is six years after the Supreme Court denied certiorari in the judicial proceeding. On October 10, 2012 the Company filed a Plan of Operations with the USFS in compliance with the reality check provision of the Decree. The question of the adequacy of the Water Diligence Application is pending.

Appeal of Modification – Notice of Intent to Conduct Prospecting for the Mt. Emmons Project

On October 17, 2013, the Colorado Court of Appeals upheld the Colorado District Court and affirmed the Colorado Mined Land Reclamation Board ("MLRB") approval of the Company's Modification MD-03 ("MD-03") to the Notice of Intent for the Mt. Emmons Project (the "NOI"). On January 12, 2011, the MLRB upheld DRMS's approval of MD-03 and its determination that: (i) the activities proposed by the NOI and MD-03 are prospecting, not development or mining, (ii) the current financial warranty amount is sufficient to cover the proposed activities and (iii) DRMS's decision not to make its approval of MD-03 contingent on permits or licenses that may be required by federal, other state, or local agencies was proper.

Brigham Oil & Gas, L.P.

On June 8, 2011, Brigham Oil & Gas, L.P. ("Brigham"), as the operator of the Williston 25-36 #1H Well, filed an action in the State of North Dakota, County of Williams, in District Court, Northwest Judicial District, Case No. 53-11-CV-00495 to interplead to the court with respect to the undistributed suspended funds from this well to protect itself from potential litigation. Brigham became aware of an apparent dispute with respect to ownership of the mineral interest between the ordinary high water mark and the ordinary low water mark of the Missouri River. Brigham has suspended payment of certain proceeds of production related to the minerals in and under this property pending resolution of the apparent dispute. Energy One is a 47.2% working interest owner in this well as a result of a participation agreement and a joint operating agreement with Brigham and Energy One's legal position is aligned with Brigham. All funds due to Energy One on this well have been distributed to Energy One and there are no

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undistributed suspended funds held in suspense by Brigham for Energy One. Although initially listed as a defendant in this proceeding, Brigham and Energy One anticipate filing with the court documents to change Energy One's status to an additional plaintiff.

Quiet Title Action – Dimmit County, TX

On October 4, 2013, Dimmit Wood Properties, Ltd. ("Dimmit") filed a Quiet Title Action against Chesapeake Exploration, LLC ("Chesapeake"), Crimson Exploration Operating, Inc. ("Crimson"), EXCO Operating Company, LP, OOGC America, Inc., Energy One and Liberty Energy, LLC ("Liberty") (jointly referred to as "Defendants") concerning an 800.77 gross acre oil and gas lease ("Lease") located in Dimmit County, Texas. Crimson, Energy One and Liberty received an assignment from Chesapeake of the Lease, in which Energy One has a 30% working interest. Dimmit alleges that the Lease has terminated due to the failure to achieve production in paying quantities. On October 28, 2013, the Defendants filed an answer, asserting that production in paying quantities was achieved in the primary term of the Lease with an existing producing well and that the Lease has remained in good standing and has not terminated. The Defendants also filed Counterclaims against Dimmit, including but not limited to breach of contract. No new wells have been drilled by the Defendants on the Lease.

Item 4 – Mine Safety Disclosures.

Not applicable.

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PART II

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

Market Information

Our common stock is traded on the over-the-counter market, and prices are reported on a "last sale" basis on the Nasdaq Capital Market. Quarterly high and low sale prices follow:

	High	Low
Calendar year ended December 31, 2013		
First Quarter	$2.50	$1.47
Second Quarter	2.17	1.56
Third Quarter	2.24	1.82
Fourth Quarter	3.83	2.07
Calendar year ended December 31, 2012		
First Quarter	$3.77	$2.85
Second Quarter	3.14	2.15
Third Quarter	2.49	2.12
Fourth Quarter	2.18	1.50

Holders

At March 6, 2014 the closing market price was $4.05 per share. There were approximately 1,131 shareholders of record, with 27,735,878, shares of common stock issued and outstanding at December 31, 2013.

Dividends

We did not declare or pay any cash dividends on common stock during fiscal years 2013 and 2012 and do not intend to declare any cash dividends in the foreseeable future.

Issuance of Securities in 2013

During 2013, we issued a total of 83,276 shares of common stock. These issuances were comprised of 53,276 shares pursuant to the terms of our ESOP and 30,000 shares issued pursuant to our 2001 Stock Compensation Plan (comprised of 10,000 shares each to the CEO, COO and General Counsel). The ESOP funding represents the minimum required amount during 2013.

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, 2013, 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. 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 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.

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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

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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,				
	2013	2012	2011	2010	2009
Current assets	$13,161	$26,015	$41,604	$50,562	$85,300
Current liabilities	7,191	13,253	20,937	18,763	8,672
Working capital	5,970	12,762	20,667	31,799	76,628
Total assets	126,801	140,827	162,439	156,016	146,723
Long-term obligations(1)	10,553	11,457	13,532	1,150	973
Shareholders' equity	109,057	116,117	126,781	130,688	129,133

(1) Includes $812,000 of accrued reclamation costs at December 31, 2013, $686,000 at December 31, 2012, $510,000 at December 31, 2011, $303,000 at December 31, 2010, and $211,000 at December 31, 2009

	(In thousands except per share data) For the years ended December 31,				
	2013	2012	2011	2010	2009
Operating revenues	$33,647	$32,534	$30,958	$26,548	$7,581
Loss from continuing operations	(4,991)	(10,344)	(5,216)	(986)	(9,935)
Other income & expenses	(2,695)	849	(717)	(332)	(1,331)
Loss before income taxes and discontinued operations	(7,686)	(9,495)	(5,933)	(1,318)	(11,266)
Benefit from income taxes	--	44	3,755	1,860	2,562
Discontinued operations, net of tax	307	(1,794)	(2,629)	(1,314)	526
Net loss	$(7,379)	$(11,245)	$(4,807)	$(772)	$(8,178)
Per share financial data					
Operating revenues	$1.22	$1.18	$1.14	$0.99	$0.35
Loss from continuing operations	(0.18)	(0.38)	(0.19)	(0.04)	(0.46)
Other income & expenses	(0.10)	0.03	(0.03)	(0.01)	(0.06)
Gain (loss) before income taxes and discontinued operations	(0.28)	(0.34)	(0.22)	(0.05)	(0.52)
Benefit from income taxes	--	--	0.14	0.07	0.12
Discontinued operations, net of tax	0.01	(0.07)	(0.10)	(0.05)	0.02
Net loss per share basic and diluted	$(0.27)	$(0.41)	$(0.18)	$(0.03)	$(0.38)
Basic shares outstanding	27,678,698	27,466,549	27,238,869	26,763,995	21,604,959
Diluted shares outstanding	27,678,698	27,466,549	27,238,869	26,763,995	21,604,959

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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 changes in commodity prices, political or regulatory events, and other matters, including as discussed below. 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

We are an independent energy company focused on the acquisition and development of oil and gas producing properties in the continental United States. Our business is currently focused in South Texas, the Williston Basin in North Dakota and Montana, and Louisiana. However, we do not intend to limit our focus to these geographic areas. We continue to focus on increasing production, reserves, revenues and cash flow from operations while managing our level of debt.

We currently explore for and produce oil and gas through a non-operator business model; however, we may operate oil and gas properties for our own account and may expand our holdings or operations into other areas. As a non-operator, we rely on our operating partners to propose, permit and manage wells. Before a well is drilled, the operator is required to provide all oil and gas interest owners in the designated well the opportunity to participate in the drilling costs and revenues of the well on a pro-rata basis. After the well is completed, our operating partners also transport, market and account for all production.

We are also involved in the exploration for and development of minerals (molybdenum) through our ownership of the Mt. Emmons Project in Colorado. Our carrying capitalized dollar amounts in each of these areas at December 31, 2013 and December 31, 2012 were as follows:

	(In thousands)	
	December 31, 2013	December 31, 2012
Unproved oil and gas properties	$7,478	$9,169
Proved oil and gas properties	79,444	76,465
Undeveloped mining properties	20,739	20,739
	$107,661	$106,373

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Oil & Gas Activities

In 2013, we had the following financial and operational results:

Revenue growth. In 2013, we recognized record revenues from oil and natural gas production of $33.6 million as compared to $32.5 million during the year ended December 31, 2012.

Reserves. At December 31, 2013, our proved reserves were 3,855,033 BOE as compared to 2,913,324 BOE at December 31, 2012. The following table details our proved reserves by state for the years ended December 31, 2013 and 2012:

State	2013	2012	% Change	
Texas				
Oil (Bbls)	1,098,206	349,727	214	%
Natural Gas (Mcf)	1,027,877	337,160	205	%
Equivalent (BOE)	1,269,520	405,923	213	%
PV-10 (1)	$61,187,000	$16,499,000	271	%
North Dakota				
Oil (Bbls)	2,333,873	2,235,924	4	%
Natural Gas (Mcf)	1,100,527	1,044,950	5	%
Equivalent (BOE)	2,517,295	2,410,085	4	%
PV-10 (1)	$51,779,000	$57,714,000	-10	%
Louisiana				
Oil (Bbls)	27,634	27,985	-1	%
Natural Gas (Mcf)	243,504	415,977	-41	%
Equivalent (BOE)	68,218	97,316	-30	%
PV-10 (1)	$2,116,000	$2,251,000	-6	%
TOTAL				
Oil (Bbls)	3,459,713	2,613,636	32	%
Natural Gas (Mcf)	2,371,908	1,798,087	32	%
Equivalent (BOE)	3,855,033	2,913,324	32	%
PV-10 (1)	$115,082,000	$76,464,000	51	%

(1) The standard mesaure PV-10 calculation is presented in the Supplemental Financial Information on Oil and Natural Gas Exploration, Development and Production Activities section located in Part II, Item 8 of this report. A reconciliation between the PV-10 reserve value and the after tax value is shown in Part I, Item I of this report.

Production. Our 2013 annual production was 424,933 BOE, or 1,164 BOE/d, as compared to 444,702 BOE, or 1,215 BOE/d, in 2012.

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Financial flexibility. Our Credit Facility has a maximum loan amount of $100.0 million, a current borrowing base of $25.0 million and a maturity date of July 30, 2017. At December 31, 2013, we had $9.0 million outstanding under the Credit Facility. See "Capital Resources – Wells Fargo Senior Credit Facility" below.

Commodity prices. Our average realized oil price in 2013 was $90.81 per Bbl (excluding the impact of our economic hedges), or $8.43 higher than the 2012 price of $82.38. Our average natural gas price realized during 2013 was $4.66 per Mcf, $1.41 per Mcf higher than the 2012 price of $3.25. Commodity prices are affected by changes in market demand, overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. Our financial results are significantly dependent on commodity prices, particularly oil prices, which are beyond our control and have been and are expected to remain volatile.

Through Energy One, from time to time, we enter into commodity derivative contracts ("hedges"), typically costless collars and fixed price swaps. U.S. Energy is a guarantor of Energy One's obligations under the hedges. The objective of our hedging program is to reduce the effect of price changes on a portion of our future oil production, achieve more predictable cash flows in an environment of volatile oil and gas prices and to manage our exposure to commodity price risk. The use of these derivative instruments limits the downside risk of adverse price movements. However, such use may limit our ability to benefit from favorable price movements. Energy One may add incremental derivatives to hedge additional production, restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of its existing positions.

The Dodd-Frank Act included provisions generally requiring over-the-counter derivative transactions to be executed through an exchange or centrally cleared. On July 10, 2012, the CFTC and the SEC adopted final joint rules under Title VII of the Dodd-Frank Act, which define certain terms and determine certain types of transactions that will be regulated under the Dodd-Frank Act swap rules. The issuance of these final rules also triggers compliance dates for a number of other final Dodd-Frank Act rules. The ultimate effect on our business of these new rules and any additional regulations is currently uncertain. Under CFTC rules we believe our derivative activity will qualify for the commercial end-user exception, which exempts derivatives intended to hedge or mitigate commercial risk from the mandatory swap clearing requirement if certain requirements are satisfied. However, certain other rules and regulations could require us to post margin in connection with commodity price risk management activities. Although we cannot predict the ultimate effect of additional rules and regulations in this area, they may result in increased costs and cash collateral requirements for the types of derivative instruments we use to manage our financial risks related to volatility in oil prices and could make it impracticable to implement our hedging strategy.

Drilling programs. We have active agreements with several oil and gas exploration and production companies. Our working interest varies by project, but typically ranges from approximately 1% to 62%. These projects may result in numerous wells being drilled over the next three to five years. We are also actively pursuing the potential acquisition of additional exploration, development or production stage oil and gas properties or companies. The following table details our interests in producing wells as of December 31, 2013 and 2012.

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	December 31,			
	2013		2012	
	Gross	Net (1)	Gross	Net (1)
Williston Basin:				
Productive wells	91.00	10.43	66.00	10.61
Wells being drilled or awaiting completion	10.00	0.27	4.00	0.20
Gulf Coast/South Texas:				
Productive wells	3.00	0.56	3.00	0.56
Wells being drilled or awaiting completion	--	--	--	--
Eagle Ford/Buda:				
Productive wells	8.00	2.25	3.00	0.90
Wells being drilled or awaiting completion	1.00	0.30	--	--
Austin Chalk:				
Productive wells	11.00	2.98	11.00	2.98
Wells being drilled or awaiting completion	--	--	--	--
Total:				
Productive wells	113.00	16.22	83.00	15.05
Wells being drilled or awaiting completion	11.00	0.57	4.00	0.20

(1) Net working interests may vary over time under the terms of the applicable contracts.

Williston Basin, North Dakota

Rough Rider Prospect. We participate in fifteen 1,280 acre drilling units in the Rough Rider prospect with Brigham. From August 24, 2009 to December 31, 2013, we have drilled and completed 21 gross (6.25 net) Bakken formation wells and 2 gross (0.22 net) Three Forks formation wells under the DPA with Brigham.

During the year ended December 31, 2013, we drilled and completed 2 gross (0.09 net) wells in the Rough Rider prospect. Three additional gross (0.07 net) wells were in progress at December 31, 2013. Our net investment in the Rough Rider prospect wells was $2.7 million for the year ended December 31, 2013. Brigham operates all of the wells.

Yellowstone and SEHR Prospects. We participate in twenty-seven gross 1,280 acre spacing units in the Yellowstone and SEHR prospects with Zavanna. Through December 31, 2013, we have drilled and completed 31 gross (3.00 net) Bakken formation wells and 4 gross (0.27 net) Three Forks formation wells in these prospects. The wells are operated by Zavanna (18 gross, 2.93 net) Emerald Oil, Inc. (12 gross, 0.16 net), Murex Petroleum (2 gross, 0.13 net), Kodiak Oil & Gas Corp. (2 gross, 0.04 net) and Slawson Exploration Company, Inc. (1 gross, 0.01 net). At December 31, 2013, 3 additional gross (0.02 net) wells had been spud and were in progress.

During the year ended December 31, 2013, we completed 19 gross (0.61 net) wells in the Yellowstone and SEHR prospects. Our net investment in the Yellowstone and SEHR prospect wells was $4.8 million during the year ended December 31, 2013.

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Bakken/Three Forks Asset Package. Under the Bakken/Three Forks asset package we acquired in 2012, we participate in 23 drilling units in McKenzie, Williams and Mountrail Counties of North Dakota. At December 31, 2013, there were 33 gross (0.69 net) producing wells in these drilling units.

During the year ended December 31, 2013, we completed 4 gross (0.12 net) wells on this acreage and 4 additional gross (0.17 net) wells were drilled and awaiting completion. Our net investment in wells under the drilling units in this program was $2.5 million during the year ended December 31, 2013.

U.S. Gulf Coast (Onshore) / South Texas

We participate with three different operators in the U.S. Gulf Coast (onshore). At December 31, 2013, we had 3 gross (0.56 net) producing wells in this region. Our net investment in Gulf Coast / South Texas wells and properties was $63,000 during the year ended December 31, 2013.

Eagle Ford Shale and Buda Limestone

We participate in the Leona River and Booth-Tortuga Eagle Ford/Buda prospects with Contango and in the Big Wells Buda prospect with U.S. Enercorp. During the year ended December 31, 2013, we drilled and completed 4 gross (1.2 net) Buda limestone wells in the Booth-Tortuga prospect and 1 gross (0.15 net) well in the Big Wells prospect. One gross (0.30 net) well was temporarily abandoned due to down hole mechanical issues and it is expected that the operator will reenter the wellbore at a later date for a Buda sidetrack opportunity. One additional Buda limestone well (0.30 net) had been spud as of December 31, 2013. Our net investment in these wells, including lease acquisition costs in the prospects during the year ended December 31, 2013, was $10.6 million.

Impairment of Proved Properties

During the year ended December 31, 2013, the Company recorded a proved property impairment of $5.8 million related to its oil and gas assets. The impairment, which was recorded in the first quarter of 2013, was primarily due to a decline in the price of oil, additional capitalized costs and changes in production.

2013 Production Results

The following table provides a regional summary of our production during the year ended December 31, 2013:

	Williston Basin	Gulf Coast / South Texas	Eagle Ford / Buda	Austin Chalk	Total
2013 Production					
Oil (Bbl)	280,789	1,610	53,603	7,717	343,719
Gas (Mcf)	145,586	190,311	69,022	3,433	408,352
NGLs (Bbl)	9,654	124	2,788	589	13,155
Equivalent (BOE)	314,707	33,453	67,895	8,878	424,933
Avg. Daily Equivalent (BOE/d)	862	92	186	24	1,164
Relative percentage	74%	8%	16%	2%	100%

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Other

Minerals (molybdenum). The Mt. Emmons Project is located near Crested Butte, Colorado and includes a total of 160 fee acres, 25 patented and approximately 1,345 unpatented mining and mill site claims, which together approximate 9,853 acres, or over 15 square miles of claims and fee lands. Historical records filed by predecessor owners of the Mt. Emmons Project with the 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 will be successful in permitting the property. Our net investment in this property at December 31, 2013 was $20.7 million.

Geothermal. We own a 19.54% interest in SST, a geothermal limited partnership. In 2013, we recorded an equity loss from SST in 2013 of $104,000. Based on historical losses, lack of current marketability of the properties and current market conditions, management determined that the Company's investment in SST was impaired as of December 31, 2013. As a result, the Company recorded an impairment charge of $2.2 million to write off the carrying amount of the investment in SST at December 31, 2013, to zero. We have notified SST that we do not intend to fund any cash calls, which will result in a dilution of our ownership in SST if future cash calls are made.

Additional Comparative Data

The following table provides information regarding selected production and financial information for the year ended December 31, 2013 and the immediately preceding three quarters.

	For the Three Months Ended			
	December 31, 2013	September 30, 2013	June 30, 2013	March 31, 2013
	(in Thousands, except for production data)			
Production (BOE)	123,246	101,987	101,026	98,674
Oil, gas and NGL production revenue	$9,271	$8,582	$7,915	$7,879
Unrealized and realized derivative gain (loss)	$255	$(1,075)	$347	$(602)
Lease operating expense	$1,393	$2,006	$1,765	$1,966
Production taxes	$835	$871	$800	$833
DD&A	$3,744	$3,205	$3,213	$3,461
General and administrative	$1,710	$1,337	$1,319	$1,307
Mineral holding costs	$294	$410	$297	$227
Water treatment plant	$603	$394	$403	$417
Income (loss) from continuing operations	$(1,217)	$(706)	$367	$(6,130)

Results of Operations

Three Months Ended December 31, 2013 Compared with the Three Months Ended December 31, 2012

During the three months ended December 31, 2013, we recorded a net loss after taxes of $1.2 million, or $0.04 per share basic and diluted as compared to a net loss after taxes of $7.9 million, or $0.29 per share basic and diluted during the same period of 2012. Significant components of the changes in results of operations for the three months ended December 31, 2013 as compared to the three months ended December 31, 2012 are as follows:

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Oil and Gas Operations. Oil and gas operations generated operating income of $3.3 million during the quarter ended December 31, 2013 as compared to operating income of $1.4 million during the quarter ended December 31, 2012, excluding the $4.7 million non-cash impairment taken on our oil and gas properties during the three months ended December 31, 2012. The following table summarizes production volumes, average sales prices and operating revenues for the three months ended December 31, 2013 and 2012:

	Three Months Ended December 31, 2013	Three Months Ended December 31, 2012	Increase (Decrease)
Production volumes			
Oil (Bbls)	96,399	90,798	5,601
Natural gas (Mcf)	127,933	84,879	43,054
Natural gas liquids (Bbls)	5,525	2,878	2,647
Equivalent (BOE)	123,246	107,823	15,424
Avg. Daily Equivalent (BOE/d)	1,340	1,172	168
Average sales prices			
Oil (per Bbl)	$87.26	$83.39	$3.87
Natural gas (per Mcf)	5.05	3.83	1.22
Natural gas liquids (per Bbl)	38.55	49.00	(10.45)
Equivalent (BOE)	75.22	74.55	0.68
Operating revenues (in thousands)			
Oil	$8,412	$7,572	$840
Natural gas	646	325	321
Natural gas liquids	213	141	72
Total operating revenue	9,271	8,038	1,233
Lease operating expense	(1,393)	(1,969)	576
Production taxes	(835)	(854)	19
Impairment	--	(4,666)	4,666
Income before depreciation, depletion and amortization	7,043	549	6,494
Depreciation, depletion and amortization	(3,744)	(3,812)	68
Income	$3,299	$(3,263)	$6,562

During the three months ended December 31, 2013, we produced 123,246 BOE, or an average of 1,340 BOE/d as compared to 107,823 BOE and 1,172 BOE/d during the three months ended December 31, 2012. Portions of our natural gas production are sent to gas processing plants to extract from the gas various natural gas liquids (“NGLs”) that are sold separately from the remaining natural gas. We sell some of our gas before processing and some after processing but in both cases receive revenues based on a share of post-processing proceeds from plant sales of the extracted NGLs and the remaining natural gas. In the table above, our share of processing costs is classified as lease operating expenses.

We recognized $9.3 million in revenues during the three months ended December 31, 2013 as compared to $8.0 million during the same period of the prior year. The $1.2 million increase in revenue is primarily due to higher realized oil and gas prices from higher oil and gas sales volumes in the three months ended December 31, 2013 when compared to the same period in 2012. The increase in production is primarily from Buda formation wells in our Booth-Tortuga prospect.

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Our average net realized price (operating revenue per BOE) for the three months ended December 31, 2013 was $75.22 per BOE compared with $74.55 for the same period in 2012. The increase in our equivalent realized price for production corresponds with higher average oil and natural gas prices in 2013 when compared with the same period in 2012. Due to takeaway constraints, the discount, or differential, for oil prices in the Williston Basin has ranged from $4.17 to $24.16 per barrel during 2013. Until additional takeaway capacity is available, we expect this differential to continue (with the amount of the differential varying over time) and that our oil sales revenue will be affected by lower realized prices.

We experienced a $576,000 reduction in lease operating expenses during the three months ended December 31, 2013 as compared to those expenses incurred during the same period of 2012. The reductions were in lease operating expenses of $400,000 and workover expenses of $195,000.

Our depletion, depreciation and amortization (DD&A) rate for the three months ended December 31, 2013 was $30.38 per BOE compared to $35.35 per BOE for the same period in 2012. Our DD&A rate can fluctuate as a result of changes in drilling and completion costs, impairments, divestitures, changes in the mix of our production, the underlying proved reserve volumes and estimated costs to drill and complete proved undeveloped reserves.

Mt. Emmons and Water Treatment Plant Operations. We recorded $603,000 in costs and expenses for the water treatment plant and $410,000 for holding costs for the Mt. Emmons molybdenum property during the three months ended December 31, 2013. During the three months ended December 31, 2012, we recorded $424,000 in operating costs related to the water treatment plant and $204,000 in holding costs.

General and Administrative. General and administrative expenses increased by $212,000 during the three months ended December 31, 2013 as compared to general and administrative expenses for the three months ended December 31, 2012. Higher general and administrative costs in 2013 are primarily a result of increases of $272,000 in compensation expense and $131,000 in professional services. The increases were partially offset by decreases of $73,000 in contract services, $50,000 in general taxes, $19,000 in travel costs and $39,000 in other operating costs.

Other Income and Expenses. We recognized an unrealized and realized derivative gain of $255,000 in the fourth quarter of 2013 compared to a loss of $5,000 for the same period in 2012. The 2013 amount includes a gain on unrealized changes in the fair value of our commodity derivative contracts of $319,000 and realized cash settlement losses on derivatives of $64,000

Gain on the sale of assets increased to $31,000 during the quarter ended December 31, 2013 compared to a loss of $1,000 during the quarter ended December 31, 2012. We recorded equity losses of $64,000 and $191,000 from the investment in SST during the quarters ended December 31, 2013 and 2012, respectively. Additionally, in December 2013, the Company recorded an impairment loss of $2.2 million on the investment in SST.

Interest income was $4,000 and $1,000 during the quarters ended December 31, 2013 and 2012, respectively.

Interest expense decreased to $55,000 during the quarter ended December 31, 2013 from $75,000 during the quarter ended December 31, 2012.

Discontinued Operations. We recorded losses of $3,000 and $548,000, net of taxes, from Remington Village during the quarters ended December 31, 2013 and December 31, 2012, respectively. Higher

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losses in the quarter ended December 31, 2012 as compared to the quarter ended December 31, 2013 were primarily a result of a $630,000 impairment recorded in the three months ended December 31, 2012.

Year Ended December 31, 2013 Compared with the Year Ended December 31, 2012

During the year ended December 31, 2013, we recorded a net loss after taxes of $7.4 million, or $0.27 per share basic and diluted, as compared to a net loss after taxes of $11.2 million, or $0.41 per share basic and diluted during the year ended December 31, 2012. Significant components of the changes in results of operations for the year ended December 31, 2013 as compared to the year ended December 31, 2012 are as follows:

Oil and Gas Operations. Before impairment, oil and gas operations produced operating income of $9.6 million during the year ended December 31, 2013 as compared to operating income of $6.9 million during the year ended December 31, 2012. The following table summarizes production volumes, average sales prices and operating revenues for the year ended December 31, 2013 and 2012:

	Year Ended December 31,		Increase
	2013	2012	(Decrease)
Production volumes			
Oil (Bbls)	343,719	373,531	(29,812)
Natural gas (Mcf)	408,352	347,811	60,541
Natural gas liquids (Bbls)	13,155	13,203	(48)
Equivalent (BOE)	424,933	444,702	(19,770)
Avg. Daily Equivalent (BOE/d)	1,164	1,215	(51)
Average sales prices			
Oil (per Bbl)	$90.81	$82.38	$8.43
Natural gas (per Mcf)	4.66	3.25	1.41
Natural gas liquids (per Bbl)	40.44	47.79	(7.35)
Equivalent (BOE)	79.18	73.16	6.03
Operating revenues (in thousands)			
Oil	$31,214	$30,772	$442
Natural gas	1,901	1,131	771
Natural gas liquids	532	631	(99)
Total operating revenue	33,647	32,534	1,114
Lease operating expense	(7,130)	(7,301)	171
Production taxes	(3,339)	(3,487)	148
Impairment	(5,828)	(5,189)	(639)
Income before depreciation, depletion and amortization	17,350	16,557	794
Depreciation, depletion and amortization	(13,623)	(14,893)	1,270
Income	$3,727	$1,664	$2,064

During the year ended December 31, 2013, we produced 424,933 BOE, or an average of 1,164 BOE/d as compared to 444,702 BOE and 1,215 BOE/d during the year ended December 31, 2012. Portions of our natural gas production are sent to gas processing plants to extract from the gas various NGLs that are sold separately from the remaining natural gas. We sell some of our gas before processing and some after processing but in both cases receive revenues based on a share of post-processing proceeds from plant

sales of the extracted NGLs and the remaining natural gas. In the table above, our share of processing costs is classified as lease operating expenses.

We recognized $33.6 million in revenues during the year ended December 31, 2013 as compared to $32.5 million during the prior year. The $1.1 million increase in revenue is primarily due to higher average realized prices for oil and natural gas in 2013 when compared to 2012, but was partially offset by lower oil sales volumes in 2013. Revenue from oil sales was higher in the year ended December 31, 2013 when compared to the same period in 2012, primarily due to increased realized prices for oil. This increase was partially offset by production declines from wells in the Williston Basin and a 35% reduction of our working and net revenue interest upon payout in the first group of six wells drilled with Brigham.

Our average net realized price (operating revenue per BOE) for the year ended December 31, 2013 was $79.18 per BOE compared with $73.16 for 2012. The increase in our equivalent realized price for production corresponds with higher average oil and natural gas prices in 2013 when compared with 2012. Due to takeaway constraints, the discount, or differential, for oil prices in the Williston Basin ranged from $4.17 to $24.16 per barrel during 2013. Until additional takeaway capacity is available, we expect this differential to continue (with the amount of the differential varying over time) and that our oil sales revenue will be affected by lower realized prices.

Lease operating expenses were $7.1 million and $7.3 million for the years ended December 31, 2013 and 2012, respectively. Lease operating expenses were comprised of $6.3 million in lease operating costs and $846,000 in workover costs for the year ended December 31, 2013. Lease operating expenses were comprised of $5.5 million in lease operating costs and $1.8 million in workover costs for the year ended December 31, 2012.

During the year ended December 31, 2013, the Company recorded a proved property impairment of $5.8 million related to its oil and gas assets. The impairment, which was recorded in the first quarter of 2013, was primarily due to a decline in the price of oil, additional capitalized costs and changes in production. During the year ended December 31, 2012, the Company recorded a proved property impairment of $5.2 million, primarily due to a decline in natural gas prices, higher projected capitalized well costs and higher projected lease operating expenses.

Our depletion, depreciation and amortization (DD&A) rate for the year ended December 31, 2013 was $32.06 per BOE compared to $33.49 per BOE for the same period in 2012. Our DD&A rate can fluctuate as a result of impairments, divestitures, changes in the mix of our production, the underlying proved reserve volumes and estimated costs to drill and complete proved undeveloped reserves.

Mt. Emmons and Water Treatment Plant Operations. We recorded $1.8 million in costs and expenses for the water treatment plant and $1.2 million for holding costs for the Mt. Emmons molybdenum property during the year ended December 31, 2013. During the year ended December 31, 2012, we recorded $2.0 million in operating costs related to the water treatment plant and $921,000 in holding costs.

General and Administrative. General and administrative expenses decreased by $1.1 million during the year ended December 31, 2013 as compared to general and administrative expenses for the year ended December 31, 2012. Lower general and administrative costs in 2013 are primarily a result of reductions of $384,000 in contract services, $253,000 in depreciation expense, $130,000 in compensation expense, $143,000 in travel costs, $50,000 in bank charges, $45,000 in professional services and $30,000 in other operating costs.

Other Income and Expenses. We recognized an unrealized and realized derivative loss of $1.1 million in the year ended December 31, 2013 compared to a gain of $1.1 million in 2012. The 2013 amount includes a loss on unrealized changes in the fair value of our commodity derivative contracts of $737,000 and realized cash settlement losses on derivatives of $338,000.

During the year ended December 31, 2013, we sold our corporate aircraft and related facilities and other miscellaneous equipment. As a result, we recorded a gain on the sale of assets during the period in the amount of $760,000. During the year ended December 31, 2012, we recorded a loss on the sale of assets of $12,000.

We recorded equity losses of $104,000 and $359,000 from the investment in SST during the year ended December 31, 2013 and 2012, respectively. Additionally, in December 2013, the Company recorded an impairment loss of $2.2 million on the investment in SST.

Gain on the sale of marketable securities (shares of Sutter Gold Mining) decreased to $0 during the year ended December 31, 2013 from $82,000 during the year ended December 31, 2012.

Interest income decreased to $8,000 during the year ended December 31, 2013 from $9,000 during the year ended December 31, 2012. The decrease is a result of lower amounts of cash invested in interest bearing instruments during the nine-month period ended December 31, 2013.

As a result of higher average debt balances, interest expense increased to $284,000 during the year ended December 31, 2013 from $203,000 during the year ended December 31, 2012.

Discontinued Operations. We recorded income of $307,000, net of taxes, from Remington Village during the year ended December 31, 2013 and loss of $1.8 million, net of taxes for the year ended December 31, 2012. The $2.1 million increase in income when comparing the year ended December 31, 2013 to the year ended December 31, 2012 is primarily a result of a $1.9 million non-cash impairment recorded during the year ended December 31, 2012 and was partially offset by a $120,000 loss on the sale of discontinued operations recorded upon closing the sale of Remington Village in September 2013.

Year Ended December 31, 2012 Compared with the Year Ended December 31, 2011

During the year ended December 31, 2012, we recorded a loss of $11.2 million or $0.41 per share basic and diluted, as compared to a loss of $4.8 million, or $0.18 per share basic and diluted, during the year ended December 31, 2011. Significant components of the change in operating revenues and results of operations for the year ended December 31, 2012 as compared to the year ended December 31, 2011 were as follows:

Oil and Gas Operations. Excluding the $5.8 million non-cash impairment taken on our oil and gas properties during the period, oil and gas operations produced operating income of $6.9 million during the year ended December 31, 2012 as compared to operating income of $5.4 million during the year ended December 31, 2011. The increase in earnings from oil and gas operations was primarily due to (a) a $4.4 million increase in oil revenues during 2012 compared to 2011 and (b) $1.1 million lower lease operating expenses in the year ending December 31, 2012 as compared to the prior year. This increase was partially offset by $896,000 higher depletion expense in 2012 and a $2.8 million decrease in natural gas and natural gas liquids revenues. The following table summarizes production volumes, average sales prices and operating revenues for the years ended December 31, 2012 and 2011:

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	Year Ended December 31, 2012	2011	Increase (Decrease)
Production volumes			
Oil (Bbls)	373,531	300,329	73,202
Natural gas (Mcf)	347,811	736,261	(388,450)
Natural gas liquids (Bbls)	13,203	19,325	(6,122)
Equivalent (BOE)	444,702	442,364	2,338
Avg. Daily Equivalent (BOE/d)	1,215	1,212	3
Average sales prices			
Oil (per Bbl)	$82.38	$87.80	$(5.42)
Natural gas (per Mcf)	3.25	4.85	(1.59)
Natural gas liquids (per Bbl)	47.79	52.88	(5.09)
Operating revenues (in thousands)			
Oil	$30,772	$26,368	$4,404
Natural gas	1,131	3,568	(2,437)
Natural gas liquids	631	1,022	(391)
Total operating revenue	32,534	30,958	1,576
Lease operating expense	(7,301)	(8,450)	1,149
Production taxes	(3,487)	(3,102)	(385)
Impairment	(5,189)	--	(5,189)
Income before depreciation, depletion and amortization	16,557	19,406	(2,849)
Depreciation, depletion and amortization	(14,893)	(13,997)	(896)
Income	$1,664	$5,409	$(3,745)

During the year ended December 31, 2012, we produced approximately 444,702 BOE, or an average of 1,215 BOE/d as compared to 442,364 BOE and 1,212 BOE/d during the year ended December 31, 2011. Portions of our natural gas production are sent to gas processing plants to extract from the gas various NGLs that are sold separately from the remaining natural gas. We sell some of our gas before processing and some after processing but in both cases receive revenues based on a share of post-processing proceeds from plant sales of the extracted NGLs and the remaining natural gas. In the table above, our share of processing costs are classified in lease operating expenses.

We recognized $32.5 million in revenues during the year ended December 31, 2012 as compared to $31.0 million during the prior year. This $1.5 million increase in revenue was primarily due to higher oil sales volumes in 2012 when compared to 2011. Revenue from gas sales was lower in the year ended December 31, 2012 when compared to 2011, primarily due to production declines from our wells in the Gulf Coast.

Our average net realized price (operating revenue per BOE) for the year ended December 31, 2012 was $73.16 per BOE compared with $69.98 for 2011. The increase in our equivalent realized price for production corresponds with a higher percentage of our production coming from oil in 2012 when compared with 2011. Due to takeaway constraints, the discount, or differential, for oil prices in the Williston Basin ranged from $7 to $25 per barrel during 2012. Until additional takeaway capacity is available, we expect this differential to continue (with the amount of the differential varying over time) and that our oil sales revenue will be affected by lower realized prices.

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Lease operating expense of $7.3 million for the year ended December 31, 2012 was comprised of $5.5 million in lease operating expense and $1.8 million in workover expense. The $1.1 million reduction in total lease operating expense in 2012 as compared to 2011 was primarily a result of $2.0 million lower workover expense, partially offset by higher lease operating expenses as a result of an increase in the number of producing wells.

In 2012, the Company recorded a proved property impairment of $5.2 million related to its oil and gas assets primarily due to a decline in natural gas prices, higher projected capitalized well costs and higher projected lease operating expenses. There were no proved property impairments recorded during the year ended December 31, 2011.

Our depletion, depreciation and amortization (DD&A) rate for the year ended December 31, 2012 was $33.49 per BOE compared to $31.64 per BOE for 2011. We have been impacted by higher DD&A rates related to our Williston Basin wells due to increases in drilling and completion costs for wells in this region. Our DD&A rate can also fluctuate as a result of impairments, divestitures, changes in the mix of our production, the underlying proved reserve volumes and estimated costs to drill and complete proved undeveloped reserves.

Mt. Emmons and Water Treatment Plant Operations. We recorded $2.0 million in costs and expenses for the water treatment plant and $921,000 for holding costs for the Mt. Emmons molybdenum property during the year ended December 31, 2012. During the year ended December 31, 2011, we recorded $1.9 million in operating costs related to the water treatment plant and $486,000 in holding costs. Holding costs during 2011 were partially funded by another party under an operating agreement.

General and Administrative. General and administrative expenses decreased by $1.5 million to $6.8 million during the year ended December 31, 2012 as compared to general and administrative expenses of $8.3 million for the year ended December 31, 2011. Lower general and administrative costs in 2012 were primarily a result of $1.4 million lower stock compensation expenses, $196,000 lower wage and tax expenses, $133,000 lower depreciation expense and $70,000 lower bank charges expense. These decreases in costs were partially offset by an increase in contract services of $305,000.

Other income and expenses. We recognized an unrealized and realized derivative gain of $1.1 million in the year ended December 31, 2012 compared to a loss of $848,000 in 2011. The 2012 amount included a gain on unrealized changes in the fair value of our commodity derivative contracts of $1.1 million and a realized cash settlement gain on derivatives of $21,000.

We recorded equity losses of $359,000 and $211,000 from our investment in SST during the years ended December 31, 2012 and 2011, respectively.

Gain on the sale of marketable securities from the sale of shares of Sutter Gold Mining decreased to $82,000 during the year ended December 31, 2012 from $529,000 during the year ended December 31, 2011.

Interest income decreased to $9,000 during the year ended December 31, 2012 from $40,000 during the year ended December 31, 2011. The decrease was a result of lower amounts of cash invested in interest bearing instruments during the year, and lower interest rates received on those investments.

Interest expense decreased to $203,000 during the year ended December 31, 2012 from $326,000 during the year ended December 31, 2011. The decrease in interest expense was related primarily to lower average debt balances during 2012 when compared to 2011.

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Discontinued operations. We recorded a loss of $1.8 million, net of taxes from the discontinued operations of Remington Village during the year ended December 31, 2012 and a loss of $2.6 million, net of taxes, for the year ended December 31, 2011. The increase in income was primarily a result of a $1.9 million impairment, net of taxes recorded at December 31, 2012 as compared to an impairment of $3.1 million recorded at December 31, 2011.

We therefore recorded a net loss after taxes of $11.2 million, or $0.41 per share basic and diluted, during the year ended December 31, 2012 as compared to a net loss after taxes of $4.8 million, or $0.18 per share basic and diluted, during the year ended December 31, 2011.

Overview of Liquidity and Capital Resources

At December 31, 2013, we had $5.9 million in cash and cash equivalents. Our working capital (current assets minus current liabilities) was $6.0 million. The following table sets forth key liquidity measures for the year ended December 31, 2013 as compared to the year ended December 31, 2012:

	(In thousands)	
	December 31, 2013	December 31, 2012
Current ratio(1)	1.83 to 1	1.96 to 1
Working capital(2)	$5,970	$12,762
Total debt	$9,000	$10,200
Total cash and marketable securities less debt	$(3,076)	$(7,192)
Total stockholders' equity	$109,057	$116,117
Total debt to equity	0.08 to 1	0.09 to 1
Total liabilities to equity	0.16 to 1	0.21 to 1

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

As discussed below in Capital Resources and Capital Requirements, we project that our capital resources at December 31, 2013, together with cash flow from operations, will be sufficient to fund operations and capital projects through 2014. Given the size of our potential commitments related to our existing inventory of drilling projects, however, our requirements for additional capital could increase significantly during 2014 if we make acquisitions or elect to participate in any currently unanticipated wells. As a result, we may consider drawing down additional debt on our Credit Facility, selling or joint venturing an interest in some of our oil and gas assets, or accessing the capital markets or other alternatives, as we determine how to best fund our capital program.

The principal recurring uncertainty which affects the Company is variable prices for commodities producible from our oil, gas and mineral properties. Significant price swings can have adverse or positive effects on our business of exploring for, developing and producing oil and gas or minerals. Availability of drilling and completion equipment and crews fluctuates with the market prices for oil and natural gas and thereby affects the cost of drilling and completing wells. When prices are low there is typically less exploration activity and the cost of drilling and completing wells is generally reduced. Conversely, when prices are high there is generally more exploration activity and the cost of drilling and completing wells generally increases.

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Capital Resources

Potential primary sources of future liquidity include the following:

Oil and Gas Production. At December 31, 2013, we had 113 gross (16.22 net) producing wells. During the year ended December 31, 2013, we received an average of $2.8 million per month from these producing wells with an average operating cost of $594,000 per month (including workover costs) and production taxes of $278,000, for average net cash flows of $1.9 million per month from oil and gas production before non-cash depletion expense. We anticipate that cash flows from oil and gas operations will increase through 2014 as additional wells being drilled with Contango and other operators begin to produce. However, decreases in the price of oil and natural gas, increased operating costs and workover expenses, declines in production rates, and other factors could reduce these average monthly cash flow amounts.

Normal production declines and the back-in after payout provisions granted to Brigham, Zavanna, U.S. Enercorp and other partners will eventually decrease the amount of cash flow we receive from these wells. We anticipate drilling more Buda limestone wells with Contango and U.S. Enercorp and additional Bakken and Three Forks wells with Brigham, Zavanna and others in the future and will continue to search for additional drilling opportunities to replace these oil reserves and cash flows.

Cash on Hand. At December 31, 2013, we had $5.9 million in cash and cash equivalents.

Wells Fargo Senior Credit Facility. In July 2013, we entered into the Second Amendment to the Credit Agreement with Wells Fargo Bank, N.A., providing a $100.0 million senior secured credit facility, with a current borrowing base of $25.0 million and maturity date of July 30, 2017. As of December 31, 2013, we had available borrowings under the Credit Facility of $16.0 million. The ability to maintain and increase this facility and borrow additional funds is dependent on a number of variables, including our proved reserves and assumptions regarding the price at which oil and natural gas can be sold. We expect that our borrowing base will increase with the addition of proved properties resulting from our ongoing drilling and completion activities. We must comply with certain financial and non-financial covenants under the terms of the credit facility agreement. We were in compliance with all such covenants at December 31, 2013 and at the date of the filing of this report. For further details related to our Credit Facility, please refer to Note H – Other Liabilities and Debt in Part II, Item 8 of this report.

Capital Requirements

Our direct capital requirements during 2014 relate to the funding of our drilling programs, the potential acquisition of prospective oil and gas properties and/or existing production, payment of debt obligations, operating and capital improvement costs relating to the water treatment plant at the Mt. Emmons project and ongoing permitting activities for the Mt. Emmons project and general and administrative costs. We intend to finance our 2014 capital expenditure plan primarily from the sources described above under “Capital Resources”. We may be required to reduce or defer part of our 2014 capital expenditures if we are unable to obtain sufficient financing from these sources. We regularly review our capital expenditure budget to assess changes in current and projected cash flows, acquisition opportunities, debt requirements and other factors.

Oil and Gas Exploration and Development. Expenditures for exploration, development and acquisitions of oil and gas properties are the primary use of our capital resources. Of our $30.2 million capital expenditure budget for 2014, $12.6 million has been allocated to the Booth-Tortuga and Big Wells acreage blocks located in South Texas, $9.6 million has been allocated to drilling programs in the

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Williston Basin and $8.0 million has been allocated to the acquisition of additional acreage in South Texas and North Dakota and/or the acquisition of producing properties with associated proven reserves. Actual capital expenditures for each regional drilling program are contingent upon timing, well costs and success. If any of our drilling initiatives are not initially successful or progress more slowly than anticipated, funds allocated for that program may be allocated to other initiatives and/or acquisitions in due course. The actual number of gross and net wells could vary in each of these cases.

Mt. Emmons Molybdenum Project. We are responsible for all costs associated with the Mt. Emmons Project, which includes operation of a water treatment plant. Operating costs for the water treatment plant during 2014 are expected to be approximately $150,000 per month. Additionally, we have budgeted $2.7 million for permitting costs, holding costs and water treatment plant capital improvements that are expected to improve the plant's efficiency and reduce costs.

In 2009, 160 acres of fee land in the vicinity of the mining claims was purchased by the Company and Thompson Creek Metals Company USA ("TCM") for $4 million. TCM agreed to sell its 50% interest in the property to the Company for $1.2 million. This transaction closed on January 21, 2014.

Insurance. We have liability insurance coverage in amounts we deem sufficient and in line with industry standards for the location, stage, and type of our operations. Payment of substantial liabilities in excess of coverage could require diversion of internal capital away from regular business, which could result in diminished operations. We have property loss insurance on all major assets equal to the approximate replacement value of the assets.

Reclamation Costs. We have reclamation obligations with an estimated present value of $637,000 related to our oil and gas wells and $175,000 related to the Mt. Emmons molybdenum property. No reclamation is expected to be performed during the year ended December 31, 2014 unless a well, or wells, are abandoned due to unexpected operational challenges or if a well becomes uneconomic. As the Mt. Emmons project is developed, the reclamation liability is expected to increase. Our objective, upon closure of the proposed mine at the Mt. Emmons project, is to eliminate long-term liabilities associated with the property.

Overview of Cash Flow Activities

The following table presents changes in cash flows between the years ended December 31, 2013 and 2012. The analysis following the table should be read in conjunction with our consolidated statements of cash flows in Part II, Item 8 of this report.

	(In thousands) For the years ended December 31,		
	2013	2012	Change
Net cash provided by operating activities	$17,098	$13,139	$3,951
Net cash (used in) provided by investing activities	(18,219)	(20,877)	2,658
Net cash (used in) financing activities	(10,821)	(2,433)	(8,388)

Operating Activities. Cash provided by operations for the year ended December 31, 2013 increased to $17.1 million as compared to cash provided by operations of $13.1 million for the prior year. This $4.0 million year over year increase in cash from operating activities is part of the complete discussion of cash provided by operations in "Results of Operations" above.

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Investing Activities. Investing activities provided cash during the year ended December 31, 2013 through $2.6 million in proceeds from the sale of property and equipment related to the Company's aircraft and related facilities.

Investing activities consumed cash through the acquisition and development of oil and gas properties in the amount of $20.8 million, $42,000 from the purchase of property and equipment and $48,000 from a change in the value of restricted investments.

The $2.7 million change in investing activities during the year ended December 31, 2013 as compared to 2012 is primarily a result of: (a) $21.6 million reduction in investment in oil and gas properties in 2013 as compared to 2012, (b) $21.5 million in proceeds from the sale of oil and gas properties in 2012 with no similar sales in 2013, (c) $2.6 million in proceeds from the sale of property and equipment in 2013 as compared to $76,000 during 2012, (d) a $68,000 net increase in the value of restricted investments and (e) a $60,000 increase in the purchase of property and equipment.

Financing Activities. Financing activities consumed $10.8 million during 2013. This cash outflow was entirely related to the repayment of debt. Components of cash flow from financing activities in 2013 include the repayment of debt in the amount of $12.8 million, and new borrowings in the amount of $2.0 million.

In 2012, financing activities consumed $2.4 million. Components of cash flow from financing activities in 2012 include the repayment of debt in the amount of $12.5 million, new borrowings in the amount of $10.0 million, and $51,000 of proceeds from the issuance of common stock.

Critical Accounting Policies and Estimates

The preparation of our consolidated financial statements in conformity with generally accepted accounting principles in the United States, or GAAP, requires our management to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities at the date of our financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results may differ from these estimates under different assumptions or conditions. A summary of our significant accounting policies is detailed in Note B – Summary of Significant Accounting Polices in Part II, Item 8 of this report. We have outlined below those policies identified as being critical to the understanding of our business and results of operations and that require the application of significant management judgment.

Oil and Natural Gas Reserve Estimates. 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. Future cash inflows and future production and development costs are determined by applying prices and costs, including transportation, quality differentials, and basis differentials, applicable to each period to the estimated quantities of proved reserves remaining to be produced as of the end of that period. Expected cash flows are discounted to present value using an appropriate discount rate. For example, the standardized measure calculations require a 10 percent discount rate to be applied.

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

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engineers to estimate our proved reserves as of December 31 of each year and quarterly throughout the year. For purposes of depletion and impairment, reserve quantities are adjusted in accordance with GAAP for the impact of additions and dispositions. Changes in depletion or impairment calculations caused by changes in reserve quantities or net cash flows are recorded in the period the reserve estimates change. For additional information, please see Note E – Supplemental Oil and Gas Information on Oil and Natural Gas Exploration, Development and Production Activities in Part II, Item 8 of this report.

Oil and Natural Gas Properties, Depletion and Full Cost Ceiling Test. We follow the full cost method in accounting for our 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 property 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. The capitalized costs are amortized over the life of the reserves associated with the assets, with the amortization being expensed as depletion in the period that the reserves are produced. This depletion expense is calculated by dividing the period's production volumes by the estimated volume of reserves associated with the investment and multiplying the calculated percentage by the sum of the capitalized investment and estimated future development costs associated with the investment. Changes in our reserve estimates will therefore result in changes in our depletion expense per unit. Costs associated with production and general corporate activities are expensed in the period incurred. Unproved property costs not subject to amortization consist primarily of leasehold and seismic costs related to unproved areas. Costs are transferred into the amortization base on an ongoing basis as the properties are evaluated and proved reserves are established or impairment is determined. We will continue to evaluate these properties and costs will be transferred into the amortization base as undeveloped areas are tested. Unproved oil and natural gas properties are not amortized but are assessed, at least annually, for impairment either individually or on an aggregated basis to determine whether we are still actively pursuing the project and whether the project has been proven, either to have economic quantities of reserves or that economic quantities of reserves do not exist.

Under the full cost method of accounting, capitalized oil and gas property costs less accumulated depletion and net of deferred income taxes may not exceed an amount equal to the present value, discounted at 10%, of estimated future net revenues from proved oil and gas reserves plus the cost of unproved properties not subject to amortization (without regard to estimates of fair value), or estimated fair value, if lower, of unproved properties that are subject to amortization. Should capitalized costs exceed this ceiling, impairment would be recognized.

Derivative Instruments. We use derivative instruments, typically fixed-rate swaps and costless collars, to manage price risk underlying our oil and gas production. We may also use puts, calls and basis swaps in the future. All derivative instruments are recorded in the consolidated balance sheets at fair value. We offset fair value amounts recognized for derivative instruments executed with the same counterparty. Although we do not designate any of our derivative instruments as cash flow hedges, such derivative instruments provide an economic hedge of our exposure to commodity price risk associated with forecasted future oil and gas production. These contracts are accounted for using the mark-to-market accounting method and accordingly, we recognize all unrealized and realized gains and losses related to these contracts currently in earnings and they are classified as gain (loss) on derivative instruments, net in our consolidated statements of operations.

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Our Board of Directors sets all risk management policies and reviews the status and results of derivative activities, including volumes, types of instruments and counterparties. The master contracts with approved counterparties identify the CEO and President as Company representatives authorized to execute trades. Please refer to Note D, Commodity Price Risk Management, in Part II, Item 8 of this report for further discussion.

Mineral Properties. We capitalize 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 we subsequently determine 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, 2013 and December 31, 2012 reflect capitalized costs associated with the Mt. Emmons Project. We review our investment in the Mt. Emmons Project annually to determine if an impairment has occurred to the carrying value of the property. We have determined that no impairment is needed to the book value of the property at December 31, 2013.

Assets Held for Sale. Assets are classified as held for sale when the Company commits to a plan to sell the assets and there is reasonable certainty that the sale will take place within one year. Upon classification as held for sale, long-lived assets are no longer depreciated or depleted, and a measurement for impairment is performed to determine if there is any excess of carrying value over fair value less costs to sell. Subsequent changes to estimated fair value less the cost to sell will impact the measurement of assets held for sale if the fair value is determined to be less than the carrying value of the assets.

Asset Retirement Obligations. We account for asset retirement obligations under ASC 410-20. We record the fair value of the reclamation liability on inactive mining properties as of the date that the liability is incurred. We review the liability each quarter and determine if a change in estimate is required as well as accrete the liability on a quarterly basis for the future liability. Final determinations are made during the fourth quarter of each year. We deduct any actual funds expended for reclamation during the quarter in which it occurs.

Revenue Recognition. We record oil and natural gas revenue under the sales method of accounting. Under the sales method, we recognize revenues based on the amount of oil or natural gas sold to purchasers, which may differ from the amounts to which we are entitled based on our interest in the properties. Gas balancing obligations as of December 31, 2013 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. We measure 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.

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We recognize 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. Based on enacted tax laws, we recognize deferred income tax assets and liabilities for the expected future income tax consequences of temporary differences between the financial reporting and tax bases of assets, liabilities and carry forwards.

We recognize 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.

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 the holding and permitting costs associated with the Mt. Emmons Project.

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, Oklahoma West Texas Intermediate ("WTI") spot price for oil reached a high of $145.31 per barrel during July 2008 and a ten year low of $30.28 per barrel during December 2008. As of December 31, 2013 the Cushing WTI spot price for oil was $98.17 per barrel.

The ten year Henry Hub Gulf Coast Natural Gas Spot Price reached a high of $15.39 per MMbtu in December 2005 and the ten year low was $1.82 per MMbtu in April 2012. The price per MMbtu at December 31, 2013 was $4.31.

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 our projected 2014 investments in oil and gas properties will be profitable.

Molybdenum. The ten year high for dealer molybdenum oxide was $38.00 per pound in June 2005 and the ten year low was $8.03 per pound in April 2009. The mean price of molybdenum oxide at December 31, 2013 and December 31, 2012 was $9.75 per pound and $11.79 per pound, respectively. The price of molybdenum will have a direct impact on the development of Mt. Emmons Project.

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Contractual Obligations

We had three principal categories of contractual obligations at December 31, 2013: Debt to third parties of $9.0 million, executive retirement obligations of $865,000 and asset retirement obligations of $812,000. The debt is related to our oil and gas reserves and bears a weighted average interest rate of 2.46% per annum. This debt was drawn in three separate tranches, each with a term of six months. Principal and accrued interest is due at the end of each respective tranche's six month term. However this debt can be continued, at our election, if we remain in compliance with the covenants under the Credit Facility through July 30, 2017. The executive retirement liability will be paid out over varying periods starting after the actual projected retirement dates of the covered executives. The asset retirement obligations are expected to be retired during the next 34 years.

The following table shows the scheduled debt payment, projected executive retirement benefits and asset retirement obligations as of December 31, 2013.

	(In thousands) Payments due by period				
	Total	Less than one Year	One to Three Years	Three to Five Years	More than Five Years
Debt obligations	$9,000	$--	$--	$9,000	$--
Executive retirement	865	159	202	--	505
Asset retirement obligation	812	96	16	51	650
Totals	$10,677	$255	$218	$9,051	$1,155

Item 7A – Quantitative and Qualitative Disclosures About Market Risk

Commodity Risk. Our major market risk exposure is the commodity pricing applicable to our oil and natural gas production. Realized commodity prices received for such production are primarily driven by the prevailing worldwide price for oil and spot prices applicable to natural gas. The market prices for oil and natural gas have been highly volatile and are likely to continue to be highly volatile in the future, which could impact our prospective revenues. A 10% fluctuation in the price received for oil and natural gas production would have had an approximate $3.4 million impact on our 2013 annual revenues.

To mitigate some of our commodity risk, we use derivative instruments, typically costless collars and fixed-rate swaps, to manage price risk. We may also use puts, calls and basis swaps in the future. We do not hold or issue derivative instruments for trading purposes. The objective of utilizing the economic hedges is to reduce the effect of price changes on a portion of our future oil production, achieve more predictable cash flows in an environment of volatile oil and gas prices and to manage our exposure to commodity price risk. The use of these derivative instruments limits the downside risk of adverse price movements. However, such use may limit our ability to benefit from favorable price movements. We may, from time to time, add incremental derivatives to hedge additional production, restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of the existing positions.

Through Energy One, we have entered into commodity derivative contracts ("economic hedges") with Wells Fargo, as described below. The derivative contracts are priced using WTI quoted prices. The Company is a guarantor of Energy One's obligations under the economic hedges.

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Energy One's commodity derivative contracts as of December 31, 2013 are summarized below:

Settlement Period	Counterparty	Basis	Quantity (Bbls/day)	Strike Price		
Crude Oil Costless Collar						
01/01/14 - 06/30/14	Wells Fargo	WTI	300	Put:	$	90.00
				Call:	$	95.00
Crude Oil Costless Collar						
01/01/14 - 06/30/14	Wells Fargo	WTI	300	Put:	$	90.00
				Call:	$	97.25
Crude Oil Costless Collar						
07/01/14 - 12/31/14	Wells Fargo	WTI	300	Put:	$	90.00
				Call:	$	98.40

These contracts are accounted for using the mark-to-market accounting method and accordingly we recognize all unrealized and realized gains and losses related to these contracts currently in earnings and they are classified as gain (loss) on derivative instruments, net in our consolidated statements of operations. The net loss realized by us related to these instruments was $338,000 for the year ended December 31, 2013. We recognized realized a net gain of $21,000 for the year ended December 31, 2012 and a net loss of $2.0 million for the year ended December 31, 2011.

Subsequent to December 31, 2013 we entered into one commodity derivative contract as detailed in the table below:

Settlement Period	Counterparty	Basis	Quantity (Bbls/day)	Strike Price
Crude Oil Costless Collar				