US ENERGY CORP
Form 10-Q
November 10, 2014

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

x Quarterly report pursuant to section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended September 30, 2014 or

o Transition report pursuant to section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from ___________ to ____________

Commission File Number: 0-6814

U.S. ENERGY CORP.
(Exact name of registrant 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

Not Applicable
(Former name, address and fiscal year, if changed since last report)

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 x NO o

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 x NO o

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 definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

YES o NO x

At November 7, 2014 there were issued and outstanding 27,905,940 shares of the Company's common stock, $0.01 par value.

U.S. ENERGY CORP. and SUBSIDIARIES

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PART I. FINANCIAL INFORMATION

ITEM 1. Financial Statements

U.S. ENERGY CORP.
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
(Unaudited)
(In thousands, except shares)

	September 30, 2014	December 31, 2013
Current assets:		
Cash and cash equivalents	$ 4,363	$ 5,855
Available for sale securities	35	69
Accounts receivable trade	6,788	6,801
Commodity risk management asset	104	14
Other current assets	251	422
Total current assets	11,541	13,161
Oil and gas properties under full cost method:		
Proved oil and properties	144,649	136,521
Unproved oil and gas properties	10,144	7,478
less depletion, depreciation and amortization	(68,575)	(57,077)
Net oil and gas properties	86,218	86,922
Undeveloped mining claims	21,942	20,739
Property, plant and equipment, net of accumulated depreciation of $4,339 and $4,135	4,006	4,199
Other assets	1,804	1,780
Total assets	$ 125,511	$ 126,801

The accompanying notes are an integral part of these statements.

U.S. ENERGY CORP.
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
(Unaudited)
(In thousands, except shares)

	September 30, 2014	December 31, 2013
Current liabilities:		
Accounts payable	$ 4,938	$ 6,167
Accrued compensation	760	580
Commodity risk management liability	--	280
Other current liabilities	144	164
Total current liabilities	5,842	7,191
Noncurrent liabilities:		
Long-term debt, net of current portion	8,000	9,000
Asset retirement obligations	1,084	812
Other accrued liabilities	1,106	741
Total noncurrent liabilities	10,190	10,553
Commitments and contingencies:		
Shareholders' equity:		
Common stock, $.01 par value; unlimited shares authorized; 27,905,940 and 27,735,878 shares issued, respectively	279	277
Additional paid-in capital	123,721	123,510
Accumulated deficit	(14,475)	(14,718)
Other comprehensive loss	(46)	(12)
Total shareholders' equity	109,479	109,057
Total liabilities and shareholders' equity	$ 125,511	$ 126,801

The accompanying notes are an integral part of these statements.

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

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
Revenues:				
Oil sales	$8,682	$8,000	$24,205	$22,802
Gas sales	870	456	2,223	1,255
NGL sales	376	126	884	319
Total revenues	9,928	8,582	27,312	24,376
Operating expenses:				
Oil and gas	3,028	2,877	7,586	8,241
Oil and gas depreciation, depletion and amortization	4,621	3,205	11,498	9,879
Impairment of oil and gas properties	--	--	--	5,828
Water treatment plant	491	394	1,400	1,214
Mineral holding costs	439	410	944	934
General and administrative	2,030	1,293	5,169	3,852
Total operating expenses	10,609	8,179	26,597	29,948
Income (loss) from operations	(681)	403	715	(5,572)
Other income and (expenses):				
Realized (loss) gain on risk management activities	(84)	(307)	(616)	(274)
Unrealized gain (loss) on risk management activities	780	(768)	369	(1,056)
Gain on the sale of assets	--	19	28	729
Equity gain (loss) in unconsolidated investment	--	11	--	(40)
Miscellaneous income	(10)	50	58	80
Interest income	1	1	3	4
Interest expense	(69)	(115)	(314)	(340)
Total other income and (expenses)	618	(1,109)	(472)	(897)
Income (loss) before income taxes and discontinued operations	(63)	(706)	243	(6,469)

The accompanying notes are an integral part of these statements.

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

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
Income taxes:				
Current (provision for)	--	--	--	--
Deferred benefit from	--	--	--	--
	--	--	--	--
Income (loss) from continuing operations	(63)	(706)	243	(6,469)
Discontinued operations:				
Discontinued operations, net of taxes	--	(8)	--	430
Loss on sale of discontinued operations, net of taxes	--	(120)	--	(120)
	--	(128)	--	310
Net income (loss)	$(63)	$(834)	$243	$(6,159)
Earnings (loss) per share basic and diluted				
Earnings (loss) from continuing operations	$--	$(0.03)	$0.01	$(0.23)
Earnings from discontinued operations	--	--	--	0.01
	$--	$(0.03)	$0.01	$(0.22)
Weighted average shares outstanding				
Basic	27,899,505	27,682,602	27,808,231	27,677,382
Diluted	27,899,505	27,682,602	28,200,388	27,677,382

The accompanying notes are an integral part of these statements.

U.S. ENERGY CORP.
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Unaudited)
(In thousands)

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
Net income (loss):	$(63)	$(834)	$243	$(6,159)
Other comprehensive (loss):				
Marketable securities, net of tax	(5)	(8)	(34)	(108)
Total comprehensive income (loss)	$(68)	$(842)	$209	$(6,267)

The accompanying notes are an integral part of these statements.

U.S. ENERGY CORP.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)
(In thousands)

	For the nine months ended September 30,	
	2014	2013
Cash flows from operating activities:		
Net income (loss)	$243	$(6,159)
(Gain) from discontinued operations	--	(310)
Income (loss) from continuing operations	243	(6,469)
Adjustments to reconcile net loss to net cash provided by operations		
Depreciation, depletion & amortization	11,702	10,086
Change in fair value of commodity price risk management activities, net	(369)	1,056
Impairment of oil and gas properties	--	5,828
Equity loss from Standard Steam	--	40
(Gain) on sale of assets	(28)	(729)
Noncash compensation	937	352
Noncash services	76	48
Accounts payable	1,551	693
Net changes in assets and liabilities	18	(533)
Net cash provided by operating activities	14,130	10,372
Cash flows from investing activities:		
Acquisition and development of oil and gas properties	(24,846)	(12,614)
Acquisition of property	(1,213)	--
Proceeds from sale of assets held for sale	--	14,655
Proceeds from sale of oil and gas properties	11,515	--
Proceeds from sale of property and equipment	28	2,596
Net change in restricted investments	(51)	6
Net cash (used in) provided by investing activities:	(14,567)	4,643

The accompanying notes are an integral part of these statements.

U.S. ENERGY CORP.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)
(In thousands)

	For the nine months ended September 30, 2014	2013
Cash flows from financing activities:		
Issuance of common stock	(55)	--
Proceeds from new debt	8,000	--
Repayments of debt	(9,000)	(12,621)
Net cash (used in) financing activities	(1,055)	(12,621)
Net cash provided by operating activities of discontinued operations:	--	319
Net (decrease) increase in cash and cash equivalents	(1,492)	2,713
Cash and cash equivalents at beginning of period	5,855	2,825
Cash and cash equivalents at end of period	$4,363	$5,538
Supplemental disclosures:		
Interest paid	$245	$221
Non-cash investing and financing activities:		
Unrealized change from available for sale securities	$34	$7
Acquisition and development of oil and gas properties through accounts payable	$2,781	$1,910
Acquisition and development of oil and gas properties through asset retirement obligations	$243	$61

The accompanying notes are an integral part of these statements.

U.S. ENERGY CORP.
Notes to Condensed Consolidated Financial Statements (Unaudited)

1) Basis of Presentation

The accompanying unaudited condensed consolidated financial statements for the periods ended September 30, 2014 and September 30, 2013 have been prepared by U.S. Energy Corp. ("we," "us," "U.S. Energy" or the "Company") in accordance with generally accepted accounting principles in the United States of America ("U.S. GAAP"). The financial statements at September 30, 2014 and December 31, 2013 include the Company's wholly owned subsidiary Energy One LLC ("Energy One"), which owns the majority of the Company's oil and gas assets. The Condensed Consolidated Balance Sheet at December 31, 2013 was derived from audited financial statements. In the opinion of the Company, the accompanying condensed consolidated financial statements contain all adjustments (consisting of only normal recurring adjustments) necessary to present fairly the financial position of the Company for the reported periods. Entities in which the Company holds at least 20% ownership or in which there are other indicators of significant influence are accounted for under the equity method, whereby the Company records its proportionate share of the entities' results of operations. Certain information and footnote disclosures normally included in financial statements prepared in accordance with U.S. GAAP have been condensed or omitted and certain prior period amounts have been reclassified to conform to the current period presentation. The unaudited condensed consolidated financial statements should be read in conjunction with the Company's Annual Report on Form 10-K for the year ended December 31, 2013 (the "2013 10-K"). Subsequent events have been evaluated for financial reporting purposes through the date of the filing of this Form 10-Q.

2) Summary of Significant Accounting Policies

We follow accounting standards set by the Financial Accounting Standards Board, commonly referred to as the "FASB." The FASB determines GAAP, which we follow to ensure we consistently report our financial condition, results of operations, and cash flows.

For detailed descriptions of our significant accounting policies, please see the 2013 10-K (Note B, pages 86 to 94).

Use of Estimates

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates include oil and gas reserves used for depletion and impairment considerations, accrued revenue and related receivables, valuation of commodity derivative instruments and the cost of future asset retirement obligations. The Company evaluates its estimates on an on-going basis and bases its estimates on historical experience and on various other assumptions the Company believes to be reasonable under the circumstances. Due to inherent uncertainties, including the future prices of oil and gas, these estimates could change in the near term and such changes could be material.

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Notes to Condensed Consolidated Financial Statements (Unaudited)
(Continued)

Oil and Gas Properties

The Company follows the full cost method in accounting for its oil and gas properties. Under the full cost method, all costs associated with the acquisition, exploration and development of oil and gas properties are capitalized and accumulated in a country-wide cost center. This includes any internal costs that are directly related to development and exploration activities, but does not include any costs related to production, general corporate overhead or similar activities. Proceeds received from 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. Excluded from amounts subject to depletion are costs associated with unproved properties.

Full Cost Pool - Full cost pool capitalized costs are amortized over the life of production of proven properties. Capitalized costs at September 30, 2014 and December 31, 2013 which were not included in the amortized cost pool were $10.1 million and $7.5 million, respectively. These costs consist of exploratory wells in progress, seismic costs that are being analyzed for potential drilling locations and land costs related to unevaluated properties. No capitalized costs related to unevaluated properties are included in the amortization base at September 30, 2014 or December 31, 2013.

Ceiling Test Analysis - Under the full cost method, net capitalized costs are limited to the lower of unamortized cost reduced by the related net deferred tax liability and asset retirement obligations or the cost center ceiling. The cost center ceiling is defined as the sum of (i) estimated future net revenue, discounted at 10% per annum, from proved reserves, based on unescalated average prices per barrel of oil and per MMbtu of natural gas at the first day of each month in the 12-month period prior to the end of the reporting period and costs, adjusted for contract provisions and financial derivatives that hedge our oil and gas revenue and asset retirement obligations, (ii) the cost of properties not being amortized, and (iii) the lower of cost or market value of unproved properties included in the cost being amortized, reduced by (iv) the income tax effects related to differences between the book and tax basis of the crude oil and natural gas 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.

We perform a quarterly ceiling test for each of our oil and gas cost centers. There is only one such cost center in 2014. The reserves used in the ceiling test and the ceiling test itself incorporate assumptions regarding pricing and discount rates over which management has no influence in the determination of present value. In arriving at the ceiling test for the quarter ended September 30, 2014, we used prices of $99.08 per barrel for oil and $4.236 per MMbtu for natural gas (and adjusted for property specific gravity, quality, local markets and distance from markets) to compute the future cash flows of our producing properties. The discount factor used was 10%.

The Company recorded no proved property impairments related to its oil and gas assets during the three and nine months ended September 30, 2014. During the three and nine months ended September 30, 2013, the Company recorded proved property impairments of $0 and $5.8 million, respectively. The impairment recorded for the nine months ended September 30, 2013 was primarily due to a decline in the price of oil, additional capitalized well costs and changes in production. Management will continue to review our unproved properties based on market conditions and other changes and, if appropriate, unproved property amounts may be reclassified to the amortized base of properties within the full cost pool.

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Notes to Condensed Consolidated Financial Statements (Unaudited)
(Continued

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

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 September 30, 2014 and December 31, 2013 reflect capitalized costs associated with our Mt. Emmons molybdenum property near Crested Butte, Colorado.

Our carrying balance in the Mt. Emmons property at September 30, 2014 and December 31, 2013 is as follows:

	(In thousands)	
	September 30, 2014	December 31, 2013
Costs associated with Mount Emmons		
beginning of year	$20,739	$20,739
Property purchase [1]	1,203	--
Costs at the end of the period	$21,942	$20,739

[1]On January 21, 2014, the Company acquired Thompson Creek Metals' ("TCM") 50% interest in 160 acres of fee land in the vicinity of the Mt. Emmons project mining claims for $1.2 million. The property was originally acquired jointly by the Company and TCM in January 2009.

Properties and Equipment

Components of Property, Plant and Equipment as of September 30, 2014 and December 31, 2013 are as follows:

	(In thousands)	
	September 30, 2014	December 31, 2013
Property, plant and equipment	$8,345	$8,334
Less accumulated depreciation	(4,339)	(4,135)
Net book value	$4,006	$4,199

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Notes to Condensed Consolidated Financial Statements (Unaudited)
(Continued

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

Derivative Instruments

The Company uses derivative instruments, typically fixed-rate swaps and costless collars, to manage price risk relating to its oil and gas production. All derivative instruments are recorded in the consolidated balance sheets at fair value. The Company offsets fair value amounts recognized for derivative instruments executed with the same counterparty. Although the Company does not designate any of its 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, the Company recognizes all unrealized and realized gains and losses related to these contracts currently in earnings and classifies them as gain (loss) on derivative instruments, on a net basis, in our consolidated statements of operations. The Company may also use puts, calls and basis swaps in the future.

The Company's Board of Directors sets all risk management policies and reviews the status and results of derivative activities, including volumes, types of instruments and counterparties on a quarterly basis. These policies require that derivative instruments be executed only by the Chief Executive Officer or President. The agreements with approved counterparties identify the Chief Executive Officer and President as the only Company representatives authorized to execute trades. Please see Note 5, Commodity Price Risk Management, for further discussion.

Revenue Recognition

The Company records 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. Natural gas balancing obligations as of September 30, 2014 were not significant.

Recent Accounting Pronouncements

In April 2014, the FASB issued new authoritative accounting guidance related to the recognition and presentation of discontinued operations in the financial statements. The guidance is aimed at reducing the frequency of disposals reported as discontinued operations by focusing on strategic shifts that have or will have a major effect on an entity's operations and financial results. This authoritative accounting guidance is effective for interim and annual periods beginning after December 15, 2014, and is to be applied prospectively. The Company is currently evaluating the provisions of this authoritative guidance and assessing its impact, but does not currently believe it will have a material effect on the Company's financial statements or disclosures.

In May 2014, the FASB issued new authoritative accounting guidance related to the recognition of revenue. This authoritative accounting guidance is effective for the annual period beginning after December 15, 2016, including interim periods within that reporting period, and is to be applied using one of two acceptable methods. The Company is currently evaluating the provisions of this guidance and assessing its impact on the Company's financial statements and disclosures.

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Notes to Condensed Consolidated Financial Statements (Unaudited)
(Continued

In June 2014, the FASB issued new authoritative accounting guidance related to the recognition of share-based compensation when an award provides that a performance target can be achieved after the requisite service period. This authoritative accounting guidance may be applied either prospectively or retrospectively and is effective for annual periods and interim periods beginning after December 15, 2015. The Company is currently evaluating the provisions of this guidance and assessing its impact on the Company's financial statements and disclosures.

In August 2014, the FASB issued new authoritative guidance that requires management to evaluate whether there are conditions or events that raise substantial doubt about an entity's ability to continue as a going concern within one year after the date that the entity's financial statements are issued, or within one year after the date that the entity's financial statements are available to be issued, and to provide disclosures when certain criteria are met. This guidance is effective for the annual period ending after December 15, 2016, and for annual periods and interim periods thereafter. Early application is permitted. The Company is currently evaluating the provisions of this guidance and assessing its impact on the Company's financial statements and disclosures.

There are no other new significant accounting standards applicable to the Company that have been issued but not yet adopted by the Company as of September 30, 2014.

3) Acquisitions and Divestitures

Acquisitions

On May 7, 2014, the Company entered into a Participation Agreement with a private South Texas based oil and gas company ("Seller") to acquire 33% of the Seller's interest in approximately 12,100 gross (3,384 net) acres in Dimmit County, Texas. The acreage consists of 4,020 gross (1,181 net) acres of primary leasehold acreage and 8,080 gross (2,203 net) acres of farm-in acreage, to be earned through a continuous drilling program. The farm-in acreage has an initial two well commitment and a 12.5% working interest carry for the leaseholder (the "Farmor") in the first 10 wells. After 100% payout of all costs for the first 10 wells that are drilled under the farm-in program, the Farmor will back in for its 12.5% retained working interest in the prospect. The Seller also retained a 25% working interest back-in after 115% of project payout has been received by the Company. The Company paid $3.9 million to enter into the transaction, which included leasehold and farm-in acquisition costs as well as our proportionate share of drilling costs for the initial test well in the prospect.

Divestitures

On May 27, 2014, the Company entered into a Purchase and Sale Agreement to sell certain Williston Basin assets. Under the terms of the sale agreement, the Company sold its interest in approximately 285.70 net acres and 16 gross (0.62 net) producing wells in Williams and McKenzie Counties, North Dakota. The transaction closed in June 2014 with an effective date of January 1, 2014. The Company received $12.2 million at closing which included $681,000 in adjustments related to revenue receivable and accounts payable through the date of closing. The $11.5 million balance of the sale proceeds was recorded as a credit to our full cost pool.

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Notes to Condensed Consolidated Financial Statements (Unaudited)
(Continued)

4) Asset Retirement Obligations

We record the fair value of the reclamation liability for our inactive mining properties and our operating oil and gas 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, and we accrete the discounted 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.

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

	(In thousands)	
	September 30, 2014	December 31, 2013
Beginning asset retirement obligation	$812	$ 686
Accretion of discount	29	38
Liabilities incurred	272	131
Liabilities settled	(29)	(43)
Ending asset retirement obligation	$1,084	$ 812
Mineral properties	$184	$ 175
Oil and Gas wells	900	637
Ending asset retirement obligation	$1,084	$ 812

5) Commodity Price Risk Management

Through our wholly-owned subsidiary Energy One, we have entered into commodity derivative contracts ("economic hedges") with Wells Fargo, as described below. The derivative contracts are priced using West Texas Intermediate ("WTI") quoted prices. The Company is a guarantor of Energy One's obligations under the economic hedges. 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 manage our exposure to commodity price risk. The use of these derivative instruments limits the downside risk of adverse price movements. However, there is a risk that such use may limit our ability to benefit from favorable price movements. Energy One may, from time to time, add incremental derivatives to hedge additional production, restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of its existing positions. The Company does not engage in speculative derivative activities or derivative trading activities, nor does it use derivatives with leveraged features.

The use of derivatives involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts. The Company's derivative contracts are currently with one counterparty. The Company has a netting arrangement with the counterparty that provides for the offset of payables against receivables from separate derivative arrangements with the counterparty in the event of contract termination. The derivative contracts may be terminated by a non-defaulting party in the event of default by one of the parties to the agreement.

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U.S. ENERGY CORP.

Notes to Condensed Consolidated Financial Statements (Unaudited)
(Continued

The Company's commodity derivative instruments are measured at fair value and are included in the accompanying balance sheets as commodity price risk management assets and liabilities. Derivative instruments are recorded at fair value on the condensed consolidated balance sheet and changes in fair value are recognized in the unrealized gain (loss) on risk management activities line on the condensed consolidated statement of operations. Realized gains and losses resulting from the settlement of derivatives are recorded in the realized (loss) gain on risk management activities line on the condensed consolidated statement of income.

Energy One's commodity derivative contracts as of September 30, 2014 are summarized below:

Settlement Period	Counterparty	Basis	Quantity (Bbls/day)	Strike Price	
Crude Oil Costless Collar					
07/01/14 - 12/31/14	Wells Fargo	WTI	300	Put:	$90.00
				Call:	$98.40
Crude Oil Costless Collar					
07/01/14 - 12/31/14	Wells Fargo	WTI	300	Put:	$90.00
				Call:	$97.40

The following table details the fair value of the Company's derivative instruments, including the gross amounts and adjustments made to net the derivative instruments for the presentation in the consolidated balance sheet (in thousands):

		As of September 30, 2014		
Underlying Commodity	Location on Balance Sheet	Gross amounts of recognized assets and liabilities	Gross amounts offset in the condensed consolidated balance sheet	Net amounts of assets and liabilities presented in the condensed consolidated balance sheet
Crude oil derivative contract	Current assets	$118	$ (14)	$ 104
Crude oil derivative contract	Current liabilities	$14	$ (14)	$ --

The following table summarizes the unrealized and realized gains and losses presented in the accompanying statements of operations:

	(In thousands)			
	For the three months ended September 30,		For the nine months ended September 30,	
	2014	2013	2014	2013
Realized derivative (loss) gain	$(84)	$(307)	$(616)	$(274)
Unrealized derivative (loss) gain	$780	$(768)	$369	$(1,056)
Total realized and unrealized derivative (loss) gain	$696	$(1,075)	$(247)	$(1,330)

U.S. ENERGY CORP.

Notes to Condensed Consolidated Financial Statements (Unaudited)
(Continued

6) Fair Value Measurements

We follow authoritative guidance regarding fair value measurements for all assets and liabilities measured at fair value. That guidance establishes a fair value hierarchy that prioritizes the inputs the Company uses to measure fair value based on the significance level of the following inputs:

- Level 1 - Quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - Quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, and model-derived valuations whose inputs or significant value drivers are observable.
- Level 3 - Significant inputs to the valuation model are unobservable.

Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the nonfinancial assets and liabilities and their placement in the fair value hierarchy levels. We determine our estimate of the fair value of derivative instruments using a market approach based on several factors, including quoted prices in active markets, and quotes from third parties.

The following tables list the Company's assets and liabilities that are measured at fair value and their classification within the fair value hierarchy as of September 30, 2014 and December 31, 2013:

	(In thousands)	Fair Value Measurements at September 30, 2014 Using		
Description	September 30, 2014	(Level 1)	(Level 2)	(Level 3)
Commodity risk management assets	$118	$--	$ 118	$--
Available for sale securities	35	35	--	--
Total assets	$153	$35	$ 118	$--
Commodity risk management liability	$14	$--	$ 14	$--
Executive retirement program liability	1,345	--	--	1,345
Total liabilities	$1,359	$--	$ 14	$1,345

Fair Value
Measurements at

Description	December 31, 2013	December 31, 2013 Using (Level 1)	(Level 2)	(Level 3)
Commodity risk management assets	$14	$--	$ 14	$--
Available for sale securities	69	69	--	--
Total assets	$83	$69	$ 14	$--
Commodity risk management liability	$280	$--	$ 280	$--
Executive retirement program liability	865	--	--	865
Total liabilities	$1,145	$--	$ 280	$865

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Notes to Condensed Consolidated Financial Statements (Unaudited)
(Continued)

Fair Value of Available for Sale Securities

The fair value of available for sale securities is based on quoted market prices obtained from independent pricing services. Accordingly, the Company has classified these instruments as Level 1.

Fair Value of Commodity Derivative Instruments

The Company determines its estimate of the fair value of derivative instruments using a market approach based on several factors, including quoted market prices in active markets, quotes from third parties, the credit rating of the counterparty and the Company's own credit rating. In consideration of counterparty credit risk, the Company assessed the likelihood that the counterparty to the derivative would default by failing to make any contractually required payments. Additionally, the Company considers that it is of substantial credit quality and has the financial resources and willingness to meet its potential repayment obligations associated with the derivative transactions. At September 30, 2014 and December 31, 2013, derivative instruments utilized by the Company consist of "no premium" collars. The crude oil derivative markets are highly active. Although the Company's derivative instruments are valued using indices, the instruments themselves are traded with third-party counterparties and are not openly traded on an exchange. As such, the Company has classified these instruments as Level 2.

Fair Value of Executive Retirement Program

The executive retirement program is a standalone liability for which there is no available market price, principal market, or market participants. The Company records the estimated fair value of the long-term liability for estimated future payments under the executive retirement program based on the discounted value of estimated future payments associated with each individual in the program. The inputs available for this estimate are unobservable and are therefore classified as Level 3 inputs.

Fair Value of Financial Instruments

Our other financial instruments include cash and cash equivalents, accounts receivable, accounts payable, other current liabilities and long-term debt. The carrying amount of cash and cash equivalents, accounts receivable, accounts payable and other current liabilities approximate fair value because of their immediate or short-term maturities. The carrying value of our debt approximates its fair market value as it bears interest at variable rates over the term of the loan. The fair value and carrying value of our debt was $8.0 million as of September 30, 2014.

7) Debt

Revolving Credit Facility

Energy One, a wholly-owned subsidiary the Company, has in place a credit facility with Wells Fargo Bank, National Association. As of September 30, 2014, the maximum credit available under the credit facility was $100.0 million and the borrowing base under the facility was $24.5 million.

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Notes to Condensed Consolidated Financial Statements (Unaudited)
(Continued)

As of September 30, 2014, the Company had $8.0 million in outstanding borrowings under the credit facility. Borrowings under the credit facility are collateralized by Energy One's oil and gas producing properties. Each borrowing under the agreement has a term of six months, but can be continued at our election through July 2017 if we remain in compliance with the covenants under the facility. Our intent is to extend this debt and therefore we have classified it as a long-term liability. The current weighted average interest rate on this debt is 2.72%. As of September 30, 2014, Energy One was in compliance with all the covenants under the credit facility.

8) Shareholders' Equity

Common Stock

2001 Stock Compensation Plan. The 2001 Stock Compensation Plan terminated on April 23, 2013 and, accordingly, no shares have been issued under this plan subsequent to that date. During the nine months ended September 30, 2013, the Company issued 30,000 shares of common stock to eligible officers of the Company under the plan and recorded $48,000 in compensation expense.

The following table details the changes in common stock during the nine months ended September 30, 2014:

(Amounts in thousands, except for share amounts)

	Common Stock		Additional Paid-In
	Shares	Amount	Capital
Balance January 1, 2014	27,735,878	$ 277	$ 123,510
Exercise of employee stock options	157,950	2	(64)
Exercise of outside director options	12,112	--	8
Expense of employee options vesting	--	--	192
Expense of outside director options vesting	--	--	75
Balance September 30, 2014	27,905,940	$ 279	$ 123,721

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Notes to Condensed Consolidated Financial Statements (Unaudited)
(Continued)

Stock Option Plans

The following table represents the activity in employee stock options and non-employee director stock options for the nine months ended September 30, 2014:

	Employee Stock Options		Director Stock Options	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
Outstanding balance at December 31, 2013	2,500,949	$ 3.60	146,000	$ 2.93
Granted	--	$ --	60,000	$ 3.77
Forfeited	(3,333)	$ 2.32	--	$ --
Expired	--	$ --	--	$ --
Exercised	(400,203)	$ 2.46	(27,334)	$ 2.53
Outstanding at September 30, 2014	2,097,413	$ 3.82	178,666	$ 3.28
Exercisable at September 30, 2014	1,905,747	$ 3.99	82,333	$ 3.30
Weighted Average Remaining Contractual Life - Years		3.87		8.14
Aggregate intrinsic value of options outstanding ($ Thousands)		$ 679		$ 58

Employee Stock Option Plans. During the three months ended September 30, 2014 and 2013, we recorded $106,000 and $44,000, respectively, in compensation expense for employee stock options. During the nine months ended September 30, 2014 and 2013, we recorded $192,000 and $76,000, respectively, in compensation expense for employee stock options. As of September 30, 2014, there was $200,000 of total unrecognized compensation cost related to employee stock options, which is expected to be amortized over a weighted average period of 1.53 years. The aggregate intrinsic value of employee stock options exercised during the three and nine months ended September 30, 2014 was $19,000 and $743,000, respectively.

Director Stock Option Plans. During the three and nine months ended September 30, 2014, we issued 60,000 options to non-employee directors under the 2008 Stock Option Plan for Independent Directors. The options were issued at the closing price of $3.77 on the date of grant, vest over a three year period and expire ten years from the date of grant. These options were valued under the Black-Scholes pricing model using a risk free interest rate of 2.06%, expected life of six years and expected volatility of 65.4469%. During the three months ended September 30, 2014 and 2013, we recorded $15,000 and $16,000, respectively, in expense for options issued to non-employee directors. During the nine months ended September 30, 2014 and 2013, we recorded $75,000 and $47,000, respectively, in expense for options issued to non-employee directors. As of September 30, 2014, there was $168,000 of total unrecognized compensation cost related to director stock options, which is expected to be amortized over a weighted average period of 2.60 years. The aggregate intrinsic value of director stock options exercised during the three and nine months ended September 30, 2014 was $17,000 and $45,000, respectively.

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Notes to Condensed Consolidated Financial Statements (Unaudited)
(Continued

9) Income Taxes

The Company uses the asset and liability method of accounting for deferred income taxes. Deferred tax assets and liabilities are determined based on the temporary differences between the financial statement and tax bases of assets and liabilities. Deferred tax assets or liabilities at the end of each period are determined using the tax rate in effect at that time.

The deferred income tax assets or liabilities for an oil and gas exploration company are dependent on many variables such as estimates of the economic lives of depleting oil and gas reserves and commodity prices. Accordingly, the asset or liability is subject to continual recalculation, and revision of the numerous estimates required, and may change significantly in the event of such things as major acquisitions, divestitures, product price changes, changes in reserve estimates, changes in reserve lives, and changes in tax rates or tax laws.

The Company does not expect to pay any federal or state income tax for 2014 as a result of net operating loss carry forwards from prior years. Accounting standards require the consideration of a valuation allowance for deferred tax assets if it is "more likely than not" that some component or all of the benefits of deferred tax assets will not be realized. As of September 30, 2014, the Company maintains a full valuation allowance on its net deferred tax assets. Based on these requirements, no provision or benefit for income taxes has been recorded for deferred taxes. There were no recorded unrecognized tax benefits at the end of the reporting period.

10) Segment Information

As of September 30, 2014, we had two reportable segments: Oil and Gas and Maintenance of Mineral Properties. A summary of results of operations for the three and nine months ended September 30, 2014 and 2013, and total assets as of September 30, 2014 and December 31, 2013 by segment, are as follows:

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Notes to Condensed Consolidated Financial Statements (Unaudited)
(Continued

	(In thousands) For the three months ended September 30, 2014	2013	(In thousands) For the nine months ended September 30, 2014	2013
Revenues:				
Oil and gas	$9,928	$8,582	$27,312	$24,376
Total revenues	9,928	8,582	27,312	24,376
Operating expenses:				
Oil and gas	7,649	6,082	19,084	23,948
Mineral properties	930	804	2,344	2,148
Total operating expenses	8,579	6,886	21,428	26,096
Interest expense:				
Oil and gas	93	65	307	213
Mineral properties	--	3	--	9
Total interest expense	93	68	307	222
Operating income (loss)				
Oil and gas	$2,186	$2,435	$7,921	$215
Mineral properties	(930)	(807)	(2,344)	(2,157)
Operating income (loss) from identified segments	1,256	1,628	5,577	(1,942)
General and administrative expenses	(2,030)	(1,337)	(5,169)	(3,963)
Add back interest expense	93	68	307	222
Other revenues and expenses	618	(1,065)	(472)	(786)
Income (loss) before income taxes and discontinued operations	$(63)	$(706)	$243	$(6,469)
Depreciation depletion and amortization expense:				
Oil and gas	$4,621	$3,205	$11,498	$9,879
Mineral properties	31	31	92	95
Corporate	37	36	112	112
Total depreciation expense	$4,689	$3,272	$11,702	$10,086

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Notes to Condensed Consolidated Financial Statements (Unaudited)
(Continued

	(In thousands)	
	June 30, 2014	December 31, 2013
Assets by segment		
Oil and gas	$96,364	$97,418
Mineral	21,942	20,739
Corporate	7,205	8,644
Total assets	$125,511	$126,801

11) Earnings Per Share

Basic net income per common share is calculated by dividing net income available to common stockholders by the basic weighted-average common shares outstanding for the relevant period. The Company's earnings per share calculations reflect the impact of any repurchases of shares of common stock made by the Company. Diluted net income per common share is calculated by dividing adjusted net income by the diluted weighted-average common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for this calculation consist of in-the-money outstanding stock options (which were assumed to have been exercised at the average market price of the common shares during the reporting period). The treasury stock method is used to measure the dilutive impact of in-the-money stock options.

The following table sets forth the calculations of basic and diluted earnings per share (in thousands except share amounts and per share data):

	(In thousands except share amounts, and per share data)			
	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
Net income (loss)	$(63)	$(834)	$243	$(6,159)
Basic weighted-average common shares outstanding	27,899,505	27,682,602	27,808,231	27,677,382
Add: dilutive effect of stock options	--	--	392,157	--
Diluted weighted-average common shares outstanding	27,899,505	27,682,602	28,200,388	27,677,382
Basic net income per share	$(0.00)	$(0.03)	$0.01	$(0.22)
Diluted net income per share	$(0.00)	$(0.03)	$0.01	$(0.22)

The following options, which could be potentially dilutive in future periods, were not included in the computation of diluted net income per share because the effect would have been anti-dilutive for the periods indicated:

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
Weighted-average anti-dilutive stock options	1,067,391	2,492,195	1,059,176	2,656,188

U.S. ENERGY CORP.

Notes to Condensed Consolidated Financial Statements (Unaudited)
(Continued)

12) Equity Income in Unconsolidated Investment

The Company owns 19.54% of Standard Steam Trust, LLC ("SST"), a Denver, Colorado based private geothermal resource acquisition and development company. At December 31, 2013, we recorded an impairment of $2.2 million on the investment in SST, which reduced the carrying amount of our investment in SST to zero. Subsequently, we no longer record our share of equity in earnings or losses. During the three and nine months ended September 30, 2013, we recorded an equity gain of $11,000 and an equity loss of $40,000, respectively, from our unconsolidated investment in SST.

ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following is Management's Discussion and Analysis of significant factors that have affected liquidity, capital resources and results of operations during the three and nine months ended September 30, 2014 and 2013. The following also updates information as to our financial condition provided in our Annual Report on Form 10-K for the year ended December 31, 2013 (the "2013 10-K"). Statements in the following discussion may be forward-looking and involve risk and uncertainty (see "Forward Looking Statements"). The following discussion should also be read in conjunction with our condensed consolidated financial statements and the notes thereto.

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 and the Williston Basin in North Dakota. 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 operations to other geographic 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 molybdenum project in Colorado.

Our current capitalized amounts in the oil and gas and mining areas at September 30, 2014 and December 31, 2013 were as follows:

	(In thousands)	
	September 30, 2014	December 31, 2013
Unproved oil and gas properties	$10,144	$7,478
Proved oil and gas properties	76,074	79,444
Undeveloped mining properties	21,942	20,739
	$108,160	$107,661

Oil and Gas Activities

We have active agreements with several oil and gas exploration and production companies. Our working interest varies by project (and may vary over time depending on the terms of the relevant agreement), 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 September 30, 2014 and 2013.

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	September, 30			
	2014		2013	
	Gross	Net (1)	Gross	Net (1)
Williston Basin:				
Productive wells	94.00	10.18	82.00	10.10
Wells being drilled or awaiting completion	6.00	0.09	9.00	0.18
South Texas:				
Productive wells	33.00	8.89	16.00	4.48
Wells being drilled or awaiting completion	2.00	0.63	2.00	0.45
Gulf Coast:				
Productive wells	3.00	0.56	3.00	0.56
Wells being drilled or awaiting completion	--	--	--	--
Total:				
Productive wells	130.00	19.63	101.00	15.14
Wells being drilled or awaiting completion	8.00	0.72	11.00	0.63

(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 Statoil Oil & Gas, L.P. ("Statoil"). From August 24, 2009 to September 30, 2014, we have drilled and completed 24 gross (6.32 net) Bakken formation wells and two gross (0.22 net) Three Forks formation wells under our Drilling Participation Agreement with Statoil.

During the nine months ended September 30, 2014, we completed three gross (0.07 net) Bakken formation wells. Our net investment in the Rough Rider prospect wells was $527,000 for the nine months ended September 30, 2014. Statoil 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, LLC ("Zavanna"). Through September 30, 2014, we have drilled and completed 38 gross (3.08 net) Bakken formation wells and seven gross (0.32 net) Three Forks formation wells in these prospects. The wells are operated by Zavanna (18 gross, 2.91 net), Emerald Oil, Inc. (22 gross, 0.32 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). During the first nine months of 2014, we completed eight gross (0.09 net) wells in the Yellowstone and SEHR prospects. At September 30, 2014, six additional gross (0.02 net) wells had been spud and were in progress.

Our net investment in the Yellowstone and SEHR prospect wells was $1.7 million during the nine months ended September 30, 2014.

Bakken/Three Forks Asset Package. In 2012, we acquired approximately 400 net acres in 23 drilling units in McKenzie, Williams and Mountrail Counties of North Dakota. In June 2014, we sold our interest in eight of these 23 drilling units (approximately 285.7 net acres) for $12.2 million. At September 30, 2014, there were 23 gross (0.24 net) producing wells in the remaining 15 drilling units.
During the nine months ended September 30, 2014, our net investment in wells under the remaining drilling units in this program was $43,000.
South Texas (Eagle Ford Shale and Buda Limestone)

Booth-Tortuga and Leona River Prospects. We participate in the Booth-Tortuga and Leona River prospects with Contango Oil & Gas Company ("Contango"). At September 30, 2014, we have 30 gross (8.23 net) producing wells in these prospects, comprised of 16 gross (4.35 net) Buda limestone wells, three gross (0.90 net) Eagle Ford Shale wells and 11 gross (2.98 net) Austin Chalk wells. During the nine months ended September 30, 2014, we drilled and completed ten gross (3.0 net) Buda limestone wells in the Booth-Tortuga prospect. One additional Buda limestone well (0.30 net) was in progress at September 30, 2014. The wells are operated by Contango (28 gross, 8.08 net) and WCS Oil & Gas Corporation (2 gross, 0.15 net). Our net investment in these wells during the first nine months of 2014, including lease acquisition costs in the prospects, was $11.1 million.

Big Wells Prospect. We participate in the Big Wells prospect with U.S. Enercorp. At September 30, 2014, we have two gross (0.30 net) producing Buda limestone wells in this prospect. During the nine months ended September 30, 2014, we drilled and completed one gross (0.15 net) well in the Big Wells prospect. Our net investment in this well during the nine months ended September 30, 2014 was $810,000.

Q2 2014 Acquisition. In May 2014, the Company acquired 33% of a private South Texas based oil and gas company's (the "Seller") interest in approximately 12,100 gross (3,384 net) acres in Dimmit County, Texas. The acreage consists of 4,020 gross (1,181 net) acres of primary leasehold acreage and 8,080 gross (2,203 net) acres of farm-in acreage, to be earned through a continuous drilling program. The farm-in acreage has an initial two well commitment and a 12.5% working interest carry for the leaseholder (the "Farmor") in the first 10 wells. After 100% payout of all costs for the first 10 wells that are drilled under the farm-in program, the Farmor will back in for its 12.5% retained working interest in the prospect. The Seller also retained a 25% working interest back-in after 115% of project payout has been received by the Company. The Company paid $3.9 million to enter into the transaction, which included leasehold and farm-in acquisition costs as well as our proportionate share of drilling costs for the initial test well in the prospect.

Two gross (0.67 net) wells were drilled and completed on the acquired acreage during the nine months ended September 30, 2014. One additional well (0.33 net) was in progress at September 30, 2014. Our net investment in this acreage and wells through September 30, 2014 was $7.8 million.

Onshore U.S. Gulf Coast

We participate with three different operators in the onshore U.S. Gulf Coast area. At September 30, 2014, we had three gross producing (0.56 net) wells in this region. Our net investment in Gulf Coast wells and properties was $30,000 during the nine months ended September 30, 2014.

2014 Production Results

The following table provides a regional summary of our net production during the first nine months of 2014:

	Williston Basin	South Texas	Gulf Coast	Total
First Nine Months of 2014 Production				
Oil (Bbl)	161,931	102,482	638	265,051
Gas (Mcf)	85,824	237,776	128,959	452,559
NGLs (Bbl)	6,217	17,084	298	23,599
Equivalent (BOE)	182,452	159,195	22,429	364,076
Avg. Daily Equivalent (BOE/d)	669	583	82	1,334
Relative percentage	50.1%	43.7%	6.2%	100%

Uranium Properties

On August 14, 2014, conditioned upon the closing of a purchase and sale transaction between Anfield Resources Inc. ("Anfield") and Uranium One Inc. ("Uranium One"), the Company agreed to release Anfield from the future payment and royalty obligations stemming from the Company's 2007 sale of its uranium properties to Uranium One. In return, Anfield has agreed to pay the Company the following:

1. $2.5 million in Anfield common shares upon closing of the transactions contemplated by the asset purchase agreement between Anfield and Uranium One. The shares will be held in escrow and released in tranches over a 36 month period,
2. $2.5 million in cash paid upon 18 months of continuous commercial production, and
3. $2.5 million in cash paid upon 36 months of continuous commercial production.

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

Mount Emmons Molybdenum Project

With respect to the Mount Emmons project, the Company expects to continue scoping analysis of the Mine Plan of Operations with the U.S. Forest Service through the balance of 2014.

Additional Comparative Data

The following table provides information regarding selected production and financial information for the quarter ended September 30, 2014 and the immediately preceding three quarters.

	For the Three Months Ended			
	September 30, 2014	June 30, 2014	March 31, 2014	December 31, 2013
	(in Thousands, except for production data)			
Production (BOE)	142,484	116,499	105,093	123,246
Oil, gas and NGL production revenue	$9,928	$9,128	$8,256	$9,271
Unrealized and realized derivative gain (loss)	$696	$(612)	$(331)	$255
Lease operating expense	$2,238	$1,807	$1,250	$1,393
Production taxes	$790	$779	$722	$835
DD&A	$4,621	$3,583	$3,294	$3,744
General and administrative	$2,030	$1,533	$1,606	$1,710
Mineral holding costs	$439	$205	$300	$294
Water treatment plant	$491	$452	$457	$603
Income (loss) from continuing operations	$(63)	$56	$250	$(1,217)

Results of Operations

Three Months Ended September 30, 2014 Compared to Three Months Ended September 30, 2013

During the three months ended September 30, 2014, we recorded a net loss after taxes of $63,000, or $0.00 per share basic and diluted, as compared to a net loss after taxes of $834,000, or $0.03 per share basic and diluted, during the same period of 2013.

Oil and Gas Operations. Oil and gas operations generated operating income of $2.3 million during the quarter ended September 30, 2014 as compared to operating income of $2.5 million during the quarter ended September 30, 2013. The following table summarizes production volumes, average sales prices and operating revenues for the three months ended September 30, 2014 and 2013:

	Three Months Ended September 30, 2014	2013	Increase (Decrease)
Production volumes			
Oil (Bbls)	98,274	81,535	16,739
Natural gas (Mcf)	197,217	104,025	93,192
Natural gas liquids (Bbls)	11,341	3,114	8,227
Equivalent (BOE)	142,484	101,987	40,497
Avg. Daily Equivalent (BOE/d)	1,549	1,109	440
Average sales prices			
Oil (per Bbl)	$88.35	$98.12	$ (9.77
Natural gas (per Mcf)	4.41	4.38	0.03
Natural gas liquids (per Bbl)	33.15	40.40	(7.25
Equivalent (BOE)	69.68	84.15	(14.47
Operating revenues (in thousands)			
Oil	$8,682	$8,000	$ 682
Natural gas	870	456	414
Natural gas liquids	376	126	250
Total operating revenue	9,928	8,582	1,346
Oil and gas production expense	(2,238)	(2,006)	(232
Production taxes	(790)	(871)	81
Income before depreciation, depletion and amortization	6,900	5,705	1,195
Depreciation, depletion and amortization	(4,621)	(3,205)	(1,416
Income	$2,279	$2,500	$ (221

During the three months ended September 30, 2014, we produced 142,484 BOE, or an average of 1,549 BOE/day. In our South Texas region, production increased 332%, from 17,028 BOE to 73,531 BOE, between the two periods as a result of our Buda limestone drilling program. Production in our Bakken region decreased 20%, from 77,007 BOE to 61,305 BOE, between the two periods as a result of normal production declines and lower working interests in wells drilled in this region. We expect these regional production trends to continue. 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 oil and gas production expense.

We recognized $9.9 million in revenues during the three months ended September 30, 2014 as compared to $8.6 million during the same period in 2013. The $1.3 million increase in revenue is primarily due to higher oil and gas sales volumes in the third quarter of 2014 as compared to the third quarter of 2013.

Our average net realized price (operating revenue per BOE) for the three months ended September 30, 2014 was $69.68 per BOE compared with $84.15 per BOE for the same period in 2013. Due to takeaway constraints, the discount to West Texas Intermediate ("WTI") quoted prices, or differential, for oil prices in the Williston Basin has ranged from $17.00 to $19.00 per barrel during the three months ended September 30, 2014. 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 from this region.

Oil and gas production expense of $2.2 million for the three months ended September 30, 2014 was comprised of $2.1 million in lease operating expense and $101,000 in workover expense.

Our depletion, depreciation and amortization (DD&A) rate for the three months ended September 30, 2014 was $32.44 per BOE compared to $31.43 per BOE for the same period in 2013. 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 $491,000 in costs and expenses for the water treatment plant and $439,000 for holding costs for the Mt. Emmons molybdenum property during the three months ended September 30, 2014. During the three months ended September 30, 2013, we recorded $394,000 in operating costs related to the water treatment plant and $410,000 in holding costs.

General and Administrative Expenses. General and administrative expenses increased by $737,000 during the three months ended September 30, 2014 compared to general and administrative expenses for the three months ended September 30, 2013. The increase in general and administrative costs in 2014 is primarily a result of a $200,000 severance payment made to the Company's General Counsel upon his retirement and $507,000 in non-cash accretion expense related to the acceleration of the Company's Chief Operating Officer's executive retirement benefit upon announcement of his plan to retire at the end of 2014. The following table details the changes in the Company's general and administrative costs for the three months ended September 30, 2014 compared to the three months ended September 30, 2013:

	(In thousands) For the three months ended September 30,		
	2014	2013	Change
Executive retirement	$530	$38	$ 492
Severance compensation	200	--	200
Other compensation	756	681	75
Professional services	154	104	50
Director's fees	73	64	9
Contract Services	143	204	(61)
Bank Charges	6	30	(24)
Other costs	168	172	(4)
Total general and administrative costs	$2,030	$1,293	$ 737

Other Income and Expenses. We recognized an unrealized and realized derivative gain of $696,000 in the third quarter of 2014 compared to a loss of $1.1 million for the same period in 2013. The 2014 amount includes a gain on unrealized changes in the fair value of our commodity derivative contracts of $780,000 and realized cash settlement losses on derivatives of $84,000.

During the three months ended September 30, 2014, we recorded no gains or losses from the sale of assets. During the three months ended September 30, 2013, we recorded a gain on the sale of assets of $19,000.

During the three months ended September 30, 2013, we recorded an equity gain of $11,000 from our unconsolidated investment in SST. At December 31, 2013, we fully impaired the investment in SST. Subsequently, we no longer record our share of equity in earnings or losses of SST.

Interest income was $1,000 during each of the quarters ended September 30, 2014 and 2013.

As a result of lower average debt balances, interest expense decreased to $69,000 during the quarter ended September 30, 2014 from $115,000 during the quarter ended September 30, 2013.

Discontinued Operations. During the three months ended September 30, 2013, we recorded a loss of $128,000, net of taxes, from Remington Village. We sold this property in the third quarter of 2013 and have no income or losses from discontinued operations during the three months ended September 30, 2014.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013

During the nine months ended September 30, 2014, we recorded net income after taxes of $243,000, or $0.01 per share basic and diluted, as compared to a net loss after taxes of $6.2 million, or $0.22 per share basic and diluted during the same period of 2013.

Oil and Gas Operations. Oil and gas operations generated operating income of $8.2 million during the nine months ended September 30, 2014 as compared to operating income of $6.3 million during the nine months ended September 30, 2013, excluding a $5.8 million non-cash impairment charge taken on our oil and gas properties during the nine months ended September 30, 2013. The following table summarizes production volumes, average sales prices and operating revenues for the nine months ended September 30, 2014 and 2013:

	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	Increase (Decrease)
Production volumes			
Oil (Bbls)	265,051	247,320	17,731
Natural gas (Mcf)	452,559	280,419	172,140
Natural gas liquids (Bbls)	23,599	7,630	15,969
Equivalent (BOE)	364,076	301,687	62,389
Avg. Daily Equivalent (BOE/d)	1,334	1,105	229
Average sales prices			
Oil (per Bbl)	$91.32	$92.20	$(0.88)
Natural gas (per Mcf)	4.91	4.48	0.43
Natural gas liquids (per Bbl)	37.46	41.81	(4.35)
Equivalent (BOE)	75.02	80.80	(5.78)
Operating revenues (in thousands)			
Oil	$24,205	$22,802	$1,403
Natural gas	2,223	1,255	968
Natural gas liquids	884	319	565
Total operating revenue	27,312	24,376	2,936
Oil and gas production expense	(5,295)	(5,737)	442
Production taxes	(2,291)	(2,504)	213
Impairment	-	(5,828)	5,828
Income before depreciation, depletion and amortization	19,726	10,307	9,419
Depreciation, depletion and amortization	(11,498)	(9,879)	(1,619)
Income	$8,228	$428	$7,800

During the nine months ended September 30, 2014, we produced 364,076 BOE, or an average of 1,334 BOE/day. In our South Texas region, production increased 333%, from 36,763 BOE to 159,195 BOE, between the two periods as a result of our Buda limestone drilling program. Production in our Bakken region decreased 24%, from 239,561 BOE to 182,451 BOE, between the two periods as a result of normal production declines and lower working interests in wells drilled in this region. We expect these regional production trends to continue. 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 oil and gas production expense.

We recognized $27.3 million in revenues during the nine months ended September 30, 2014 as compared to $24.4 million during the same period in 2013. The $2.9 million increase in revenue is primarily due to higher oil and gas sales volumes in the first nine months of 2014 as compared to the first nine months of 2013.

Our average net realized price (operating revenue per BOE) for the nine months ended September 30 30, 2014 was $75.02 per BOE compared with $80.80 per BOE for the same period in 2013. Due to takeaway constraints, the discount to West Texas Intermediate ("WTI") quoted prices, or differential, for oil prices in the Williston Basin has ranged from $13.00 to $21.00 per barrel during the first nine months of 2014. 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 from this region.

Oil and gas production expense of $5.3 million for the nine months ended September 30, 2014 was comprised of $5.0 million in lease operating expense and $253,000 in workover expense. The $442,000 decrease in total oil and gas production expense in the nine months ended September 30, 2014 as compared to the same period in 2013 results from of an increase in lease operating expense of $36,000 and a reduction in workover expense of $478,000.

Our depletion, depreciation and amortization (DD&A) rate for the nine months ended September 30, 2014 was $31.58 per BOE compared to $32.75 per BOE for the same period in 2013. 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 $1.4 million in costs and expenses for the water treatment plant and $944,000 for holding costs for the Mt. Emmons molybdenum property during the nine months ended September 30, 2014. During the nine months ended September 30, 2013, we recorded $1.2 million in operating costs related to the water treatment plant and $934,000 in holding costs.

General and Administrative Expenses. General and administrative expenses increased by $1.3 million during the nine months ended September 30, 2014 compared to general and administrative expenses for the nine months ended September 30, 2013. The increase in general and administrative costs in 2014 is primarily a result of a $200,000 severance payment made to the Company's General Counsel upon his retirement, $507,000 in non-cash accretion expense related to the acceleration of the Company's Chief Operating Officer's executive retirement benefit upon announcement of his plan to retire at the end of 2014, and increases of $399,000 in professional services, $229,000 in compensation expense and $45,000 in director fees and related options expense. The following table details the changes in the Company's general and administrative costs for the nine months ended September 30, 2014 compared to the nine months ended September 30, 2013:

	(In thousands) For the nine months ended September 30,		
	2014	2013	Change
Executive retirement	$576	$69	$507
Severance compensation	200	--	200
Other compensation	2,338	2,109	229
Professional services	785	386	399
Director's fees	236	191	45
Travel	121	108	13
Contract Services	402	449	(47)
Bank Charges	22	41	(19)
Other costs	489	499	(10)
Total general and administrative costs	$5,169	$3,852	$1,317

Other Income and Expenses. We recognized an unrealized and realized derivative loss of $247,000 in the first nine months of 2014 compared to a loss of $1.3 million for the same period in 2013. The 2014 amount includes a gain on unrealized changes in the fair value of our commodity derivative contracts of $369,000 and realized cash settlement losses on derivatives of $616,000.

During the nine months ended September 30, 2014, we recorded a gain on the sale of assets of $28,000 from the sale of a piece of equipment. During the nine months ended September 30, 2013, we recorded a gain on the sale of assets of $729,000, primarily related to the sale of our corporate aircraft and related facilities.

During the nine months ended September 30, 2013, we recorded an equity loss of $40,000 from our unconsolidated investment in SST. At December 31, 2013, we fully impaired the investment in SST. Subsequently, we no longer record our share of equity in earnings or losses of SST.

Interest income was $3,000 and $4,000 during the nine months ended September 30, 2014 and 2013, respectively.

As a result of lower average debt balances, interest expense decreased to $314,000 during the nine months ended September 30, 2014 from $340,000 during the nine months ended September 30, 2013.

Discontinued Operations. During the nine months ended September 30, 2013, we recorded income of $310,000, net of taxes, from Remington Village. We sold this property in the third quarter of 2013 and had no income or losses from discontinued operations during the nine months ended September 30, 2014.

Overview of Liquidity and Capital Resources

At September 30, 2014, we had $4.4 million in cash and cash equivalents. Our working capital (current assets minus current liabilities) was $5.7 million. As discussed below in "Capital Resources and Capital Requirements", we project that our capital resources at September 30, 2014 will be sufficient to fund our operations and capital projects through the balance of 2014. Given the size of our potential commitments related to our existing inventory of drilling projects, however, our requirements for capital could increase significantly over the next several months if, among other things, we make acquisitions or elect to participate in any currently unanticipated drilling of additional wells. As a result, we may consider borrowing more than currently anticipated on our revolving 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 oil and gas. Significant price swings can have adverse or positive effects on our business of exploring for, developing and producing oil and gas. 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.

Capital Resources

Primary potential sources of future liquidity include the following:

Oil and Gas Production. At September 30, 2014, we had 130 gross (19.63 net) producing wells. During the nine months ended September 30, 2014, we received an average of $3.0 million per month from these producing wells with an average operating cost of $588,000 per month (including workover costs) and production taxes of $255,000, for average net cash flows of $2.2 million per month from oil and gas production before non-cash depletion expense. We anticipate that cash flows from oil and gas operations through the balance of 2014 will approximate average cash flows for the first nine months of 2014. 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 certain of our counterparties will eventually decrease the amount of cash flow we receive from the relevant wells. We anticipate drilling more Buda limestone wells with Contango, U.S. Enercorp and others and additional Bakken and Three Forks wells with Statoil, 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 September 30, 2014, we had $4.4 million in cash and cash equivalents.

Wells Fargo Revolving Credit Facility. On July 30, 2010, we established a senior credit facility through our wholly owned subsidiary Energy One to borrow up to $75 million (since increased to $100 million as described below) from a syndicate of banks, financial institutions and other entities, including Wells Fargo Bank, National Association, which acquired the North American reserve-based and related diversified energy lending business of our initial lending institution, BNP Paribas. The senior credit facility is being used to advance our short and mid-term goals of increasing our investment in oil and gas.

From time to time until the expiration of the credit facility (July 30, 2017), if Energy One is in compliance with the facility documents, Energy One may borrow, pay, and re-borrow funds from the lenders, up to an amount equal to the borrowing base. The borrowing base is redetermined semi-annually, taking into account updated reserve reports. Any proposed increase in the borrowing base will require approval by all lenders in the syndicate, and any proposed borrowing base decrease will require approval by lenders holding not less than two-thirds of outstanding loans and loan commitments. As of the date of this report, the commitment amount is $100 million and the borrowing base is $24.5 million. As of September 30, 2014, Energy One was in compliance with all the covenants under the revolving credit facility.

As of the date of this report, we have outstanding borrowings of $8.0 million under the credit facility.

Capital Requirements

Our direct capital requirements during the balance of 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 Mt. Emmons, 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 plan 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. Through September 30, 2014, we have spent approximately $22.3 million of our $30.2 million 2014 oil and gas capital expenditure budget. The remaining $7.9 million is currently budgeted to be spent on exploration and acquisition initiatives in South Texas and in the Williston Basin of North Dakota. Actual capital expenditures for each regional drilling program is 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 the remainder of 2014 are expected to be approximately $144,000 per month and holding costs related to the mine are expected to average $59,000 per month. Additionally, we anticipate expenditures of approximately $50,000 for water treatment plant improvements that are expected to improve the plant's efficiency and reduce costs and $200,000 for advancement of the Mine Plan of Operations.

Insurance. We have liability insurance coverage in amounts we deem sufficient and in line with industry standards for the location, stage of development, and type of assets we operate. 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 $900,000 related to our oil and gas wells and $184,000 related to the Mt. Emmons molybdenum property. No reclamation is expected to be performed in 2014 unless a well, or wells, are abandoned due to unexpected operational challenges or if a well becomes uneconomical. 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.

Cash Flows During the Nine Months Ended September 30, 2014

The following table presents changes in cash flows between the nine month periods ended September 30, 2014 and 2013. The analysis following the table should be read in conjunction with our condensed consolidated statements of cash flows in Part I, Item 1 of this report.

	(In thousands) For the nine months ended September 30, 2014	2013	Change
Net cash provided by operating activities	$14,130	$10,372	$3,758
Net cash (used in) provided by investing activities	(14,567)	4,643	(19,210)
Net cash (used in) financing activities	(1,055)	(12,621)	11,566
Net cash provided by discontinued operations	--	319	(319)

Operating Activities. Cash provided by operations for the nine month period ended September 30, 2014 increased to $14.1 million as compared to cash provided by operations of $10.4 million for the same period of 2013. This $3.7 million year over year increase in cash from operating activities is primarily due to higher oil and gas revenue and lower oil and gas operating expenses during the nine months ended September 30, 2014 as compared to the nine months ended September 30, 2013. For further discussion related to cash provided by operations, please refer to "Results of Operations" above.

Investing Activities. During the nine months ended September 30, 2014, investing activities consumed cash through the acquisition and development of oil and gas properties in the amount of $24.8 million, the acquisition of property in the amount of $1.2 million and a net change of $51,000 in restricted investments. During this period, investing activities provided cash through $11.5 million from the sale of oil and gas properties and $28,000 in proceeds from the sale of used equipment.

The $19.2 million change in investing activities during the nine months ended September 30, 2014 as compared to the same period of 2013 is primarily a result of: (a) a $12.2 million increase in acquisitions and development of oil and gas properties in the nine months ended September 30, 2014 as compared to the same period in 2013, (b) $11.5 million in proceeds from the sale of oil and gas properties as compared to no oil and gas property sales in 2013, (c) $14.7 million in proceeds from the sale of the Remington Village apartment complex in 2013 with no comparable sales in 2014, (d) $2.6 million in proceeds from the sale of property and equipment in 2013 as compared to $28,000 during the nine months ended September 30, 2014, and (e) $1.2 million purchase of property during 2014 with no property and equipment acquisitions during the same period in 2013.

Financing Activities. Financing activities consumed $1.1 million during the nine months ended September 30, 2014 from the repayment of borrowings under our credit facility, and $55,000 from the exercise of stock options. During the nine months ended September 30, 2013, financing activities consumed $12.6 million from the repayment of debt.

Critical Accounting Policies and Estimates

For detailed descriptions of our critical accounting policies and estimates, we refer you to the corresponding section of Part II, Item 7 of our 2013 10-K (please see pages 68 to 71).

Future Operations

Management intends to continue the development of our oil and gas portfolio as well as seek additional investment opportunities in the oil and natural gas sector. Long term, we intend to fund the holding and permitting costs associated with the Mt. Emmons property.

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Effects of Changes in Prices

Natural resource operations are significantly affected by changes in commodity prices. As prices for a particular commodity increase, values for prospects for that commodity typically also increase, making acquisitions of such properties more costly and sales potentially more valuable. Conversely, a price decline could enhance acquisitions of properties related to that commodity, but could also make sales of such properties more difficult. Operational impacts of changes in commodity prices are common in the oil and gas and mining industries.

At September 30, 2014, we are receiving revenues from our oil and gas business. Our revenues, cash flows, future rate of growth, results of operations, financial condition and ability to finance projected acquisitions of oil and gas producing assets are dependent upon prevailing prices for oil and gas.

Forward Looking Statements

This Form 10-Q contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements other than statements of historical facts included in and incorporated by reference into this Form 10-Q are forward-looking statements. When used in this Form 10-Q, the words "will", "expect," "anticipate," "intend," "plan," "believe," "seek," "estimate" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain these identifying words. Forward-looking statements in this Form 10-Q include statements regarding our expected future revenue, income, production, liquidity, cash flows, reclamation and other liabilities, expenses and capital projects, future capital expenditures and projects, future transactions and takeaway capacity. Because these forward-looking statements involve risks and uncertainties, actual results could differ materially from those expressed or implied by these forward-looking statements due to a variety of factors, including those associated with our ability to find oil and natural gas reserves that are economically recoverable, the volatility of oil, NGL and natural gas prices, declines in the values of our properties that have resulted in and may in the future result in additional ceiling test write downs, our ability to replace reserves and sustain production, our estimate of the sufficiency of our existing capital sources, our ability to raise additional capital to fund cash requirements for our participation in oil and gas properties and for future acquisitions, the uncertainties involved in estimating quantities of proved oil and natural gas reserves, in prospect development and property acquisitions or dispositions and in projecting future rates of production or future reserves, the timing of development expenditures and drilling of wells, hurricanes and other natural disasters and the operating hazards attendant to the oil and gas and minerals businesses. In particular, careful consideration should be given to cautionary statements made in the "Risk Factors" section of our 2013 10-K and other quarterly reports on Form 10-Q filed with the SEC, all of which are incorporated herein by reference. The Company undertakes no duty to update or revise any forward-looking statements.

Forward-looking statements also include those relating to the permitting and approval process for the Mount Emmons molybdenum project (the "Project"). There can be no assurance that U.S. Energy will receive the permits and approvals necessary to pursue the Project. In addition, such permits and approvals, if received, could be unreasonably or unexpectedly delayed or made subject to conditions that reduce the benefits of the Project or render it uneconomic. The process under NEPA may be longer than the Company expects, may involve substantial costs, and may require substantial management attention. The mine, if constructed, could be substantially different in nature, productivity and economic potential than the mine as contemplated by the Mine Plan of Operations. In addition, if constructed, the operation of the mine will be subject to a wide variety of operating, commodity-price related and financial risks.

Off-Balance Sheet Arrangements

None

Contractual Obligations

We had three principal categories of contractual obligations at September 30, 2014: Debt to third parties of $8.0 million, executive retirement obligations of $1.3 million and asset retirement obligations of $1.1 million.

The debt to third parties consists of $8.0 million in debt under our revolving credit facility. Each borrowing under the revolving credit facility has a term of six months but can be continued at our election through July 2017 if we remain in compliance with the covenants under the facility. The executive retirement liability will be paid out over varying periods starting after the actual retirement dates of the covered executives. The asset retirement obligations are expected to be retired during the next 33 years.

ITEM 3. 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, and this volatility will impact our revenues.

To mitigate some of our commodity risk, 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. 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, to achieve more predictable cash flows in an environment of volatile oil and gas prices and to manage our exposure to commodity price risk. The use of these derivative instruments limits the downside risk of adverse price movements. However, there is a risk that such use may limit our ability to benefit from favorable price movements. Energy One may, from time to time, add incremental derivatives to hedge additional production, restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of its 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 West Texas Intermediate ("WTI") quoted prices. The Company is a guarantor of Energy One's obligations under the economic hedges.

Energy One's commodity derivative contracts as of September 30, 2014 are summarized below:

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

Call: $97.40

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 such gains and losses are classified as gain (loss) on derivative instruments, net in our consolidated statements of operations. For further details regarding our derivative contracts, please refer to Note 5, Commodity Price Risk Management under Part I, Item 1 of this report.

ITEM 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of September 30, 2014, the Company's management, including its Chief Executive Officer and Chief Financial Officer, completed an evaluation of the effectiveness of the Company's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act). Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded:

i. That the Company's disclosure controls and procedures are designed to ensure (a) that information required to be disclosed by the Company in the reports it files or submits under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms, and (b) that such information is accumulated and communicated to the Company's management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure; and
ii. That the Company's disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There has been no change in our internal control over financial reporting that occurred during the quarter ended September 30, 2014 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. Legal Proceedings

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 royalty 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 suspended payment of certain royalty proceeds of production related to the minerals in and under this property pending resolution of the apparent dispute. Energy One owns a working interest, not royalty interest, in this well so no funds owed to Energy One have been withheld.

On January 28, 2013, the District Court Northwest Judicial District issued an Order for Partial Summary Judgment holding that the State of North Dakota as part of its title to the beds of navigable waterways owns the minerals in the area between the ordinary high and low watermarks on these waterways, and that this public title excludes ownership and any proprietary interest by riparian landowners. This issue has been appealed to the North Dakota Supreme Court. Energy One's legal position is aligned with Brigham, who will continue to provide legal counsel in this case for the benefit of all working interest owners.

There have been no other material changes from the legal proceedings as previously disclosed in our 2013 10-K in response to Item 3 of Part I of such Form 10-K (pages 46-48).

ITEM 1A. Risk Factors

There have been no material changes to the risk factors discussed in Part I, "Item 1A - Risk Factors" (pages 15 to 30) in the 2013 10-K which may materially affect the Company's business, financial condition or future results. Additional risks and uncertainties not currently known to the Company or that it currently deems to be immaterial also may materially adversely affect its business, financial condition and/or operating results.

ITEM 2. Unregistered Sales of Equity Securities and Use of Proceeds

None

ITEM 3. Defaults Upon Senior Securities

Not Applicable

ITEM 4. Mine Safety Disclosures

None

ITEM 5. Other Information

Not Applicable

ITEM 6. Exhibits

31.1	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification of Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as adopted by Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as adopted by Section 906 of the Sarbanes-Oxley Act of 2002
101.INS	XBRL Instance Document
101.SCH	XBRL Schema Document
101.CAL	XBRL Calculation Linkbase Document
101.LAB	XBRL Label Linkbase Document
101.PRE	XBRL Presentation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

U.S. ENERGY CORP.
(Registrant)

Date: November 7, 2014 By: /s/ Keith G. Larsen
KEITH G. LARSEN
Chairman and CEO

Date: November 7, 2014 By: /s/ Steven D. Richmond
STEVEN D. RICHMOND
Chief Financial Officer