US ENERGY CORP
Form 10-Q
November 09, 2015

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

Quarterly report pursuant to section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended September 30, 2015 or

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 NO

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§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 NO

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

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

YES NO

At November 4, 2015 there were 28,351,022 outstanding shares of the Company's common stock, $0.01 par value.

U.S. ENERGY CORP. and SUBSIDIARIES

INDEX

PART I. FINANCIAL INFORMATION

ITEM 1. Financial Statements

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

	September 30, 2015	December 31, 2014
Current assets:		
Cash and cash equivalents	$ 3,877	$ 4,010
Available for sale securities	258	25
Accounts receivable trade	1,085	3,177
Commodity risk management asset	1,002	--
Other current assets	227	288
Total current assets	6,449	7,500
Oil and gas properties under full cost method,		
Proved oil and gas properties	109,054	147,486
Unproved oil and gas properties	8,196	10,188
Exploratory wells in progress	--	2,357
less depletion, depreciation and amortization	(78,867)	(71,762)
Net oil and gas properties	38,383	88,269
Undeveloped mining claims	21,942	21,942
Property, plant and equipment, net of accumulated depreciation of $4,500 and $4,404	3,666	3,942
Other assets	1,062	1,870
Total assets	$ 71,502	$ 123,523

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, 2015	December 31, 2014
Current liabilities:		
Accounts payable	$ 8,334	$ 7,441
Accrued compensation	1,194	441
Current portion of debt	6,000	--
Other current liabilities	72	84
Total current liabilities	15,600	7,966
Noncurrent liabilities:		
Long-term debt	--	6,000
Asset retirement obligations	1,230	1,133
Other accrued liabilities	551	1,029
Total noncurrent liabilities	1,781	8,162
Commitments and contingencies:		
Shareholders' equity:		
Common stock, $0.01 par value; unlimited shares authorized 28,351,022 shares issued and 28,110,311 outstanding at September 30, 2015, 28,047,661 issued and outstanding at December 31, 2014	281	280
Additional paid-in capital	124,344	123,980
Accumulated deficit	(70,443)	(16,809)
Other comprehensive loss	(61)	(56)
Total shareholders' equity	54,121	107,395
Total liabilities and shareholders' equity	$ 71,502	$ 123,523

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,	
	2015	2014	2015	2014
Revenues:				
Oil sales	$2,258	$8,682	$7,489	$24,205
Gas sales	281	870	881	2,223
NGL sales	83	376	216	884
Total revenues	2,622	9,928	8,586	27,312
Operating expenses:				
Oil and gas	1,565	3,028	5,438	7,586
Oil and gas depreciation, depletion and amortization	2,176	4,621	7,105	11,498
Impairment of oil and gas properties	21,446	--	43,894	--
Water treatment plant	470	491	1,383	1,400
Mineral holding costs	365	439	912	944
General and administrative	1,824	2,030	4,524	5,169
Total operating expenses	27,846	10,609	63,256	26,597
(Loss) income from operations	(25,224)	(681)	(54,670)	715
Other income and (expenses):				
Realized gain (loss) on risk management activities	33	(84)	(106)	(616)
Unrealized gain on risk management activities	1,337	780	1,002	369
Gain on the sale of assets	41	--	57	28
Miscellaneous income (expense)	163	(10)	211	58
Interest income	66	1	68	3
Interest expense	(67)	(69)	(196)	(314)
Total other income and (expenses)	1,573	618	1,036	(472)
(Loss) income before income taxes	(23,651)	(63)	(53,634)	243

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,	
	2015	2014	2015	2014
Income taxes:				
Current (provision for)	--	--	--	--
Deferred benefit from	--	--	--	--
	--	--	--	--
Net (loss) income	$(23,651)	$(63)	$(53,634)	$243
(Loss) income per share basic and diluted	$(0.84)	$-	$(1.91)	$0.01
Weighted average shares outstanding				
Basic	28,051,066	27,899,505	28,048,808	27,808,231
Diluted	28,051,066	27,899,505	28,048,808	28,200,388

The accompanying notes are an integral part of these statements.
-7-

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

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
Net (loss) income:	$(23,651)	$(63)	$(53,634)	$243
Other comprehensive (loss):				
Marketable securities, net of tax	(10)	(5)	(5)	(34)
Total comprehensive (loss) income	$(23,661)	$(68)	$(53,639)	$209

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,	
	2015	2014
Cash flows from operating activities:		
Net (loss) income	$(53,634)	$243
Adjustments to reconcile net (loss) income to net cash provided by operations		
Depreciation, depletion & amortization	7,306	11,702
Change in fair value of commodity price risk management activities, net	(1,002)	(369)
Impairment of oil and gas properties	43,894	--
(Gain) on receipt of Anfield Resources stock	(238)	--
(Gain) on sale of assets	(57)	(28)
Noncash compensation	149	937
Noncash services	50	76
Accounts payable	2,548	48
Overpayment by operators	(330)	1,503
Net changes in assets and liabilities	2,560	18
Net cash provided by operating activities	1,246	14,130
Cash flows from investing activities:		
Acquisition and development of oil and gas properties	(3,876)	(24,846)
Acquisition of property, plant and equipment	(4)	(1,213)
Proceeds from sale of oil and gas properties	--	11,515
Proceeds from settlement of lawsuit	1,500	--
Proceeds from sale of property and equipment	136	28
Net change in restricted investments	885	(51)
Net cash (used in) investing activities:	(1,359)	(14,567)

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, 2015	2014
Cash flows from financing activities:		
Issuance of common stock	--	(55)
Cancellation of common stock	(20)	--
Proceeds from new debt	--	8,000
Repayments of debt	--	(9,000)
Net cash provided by (used in) financing activities	(20)	(1,055)
Net (decrease) in cash and cash equivalents	(133)	(1,492)
Cash and cash equivalents at beginning of period	4,010	5,855
Cash and cash equivalents at end of period	$3,877	$4,363
Supplemental disclosures:		
Interest paid	$129	$245
Non-cash investing and financing activities:		
Acquisition and development of oil and gas properties through accounts payable	$1,325	$2,781
Increase in oil and gas properties through asset retirement obligations	$62	$243

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, 2015 and September 30, 2014 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, 2015, September 30, 2014 and December 31, 2014 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, 2014 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, 2014 (the "2014 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 2014 10-K (Note B, pages 87 to 96).

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.

U.S. ENERGY CORP.
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, 2015 and December 31, 2014 which were not included in the amortized cost pool were $8.2 million and $12.5 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, 2015 or December 31, 2014.

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 2015. 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, 2015, we used prices of $59.21 per barrel for oil and $3.060 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%.

Primarily due to the lower oil prices, the Company recorded proved property impairments of $21.4 and $43.9 million related to its oil and gas assets during the three and nine months ended September 30, 2015, respectively. 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. Recent declines in the price of oil have significantly increased the risk of ceiling test write-downs in future periods.

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, 2015 and December 31, 2014 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, 2015 and December 31, 2014 is as follows:

	(In thousands)	
	September 30, 2015	December 31, 2014
Costs associated with Mount Emmons beginning of year	$21,942	$ 20,739
Property purchase [1]	--	1,203
Costs at the end of the period	$21,942	$ 21,942

[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, 2015 and December 31, 2014 are as follows:

	(In thousands)	
	September 30, 2015	December 31, 2014
Property, plant and equipment	$8,166	$ 8,346
Less accumulated depreciation	(4,500)	(4,404)
Net book value	$3,666	$ 3,942

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 risk management activities, on a net basis, in our consolidated statements of operations. The Company may also use puts, calls and basis swaps from time to time.

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 4, 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, 2015 were not significant.

Recent Accounting Pronouncements

Effective January 1, 2015, the Company adopted, on a prospective basis, Financial Accounting Standards Board ("FASB") Accounting Standards Update ("ASU") No. 2015-01, "Income Statement – Extraordinary and Unusual Items." This ASU simplifies income statement presentation by eliminating the concept of extraordinary items. There was no impact to the Company's financial statements or disclosures from the adoption of this standard.

In April 2015, the FASB issued new authoritative accounting guidance requiring debt issuance costs to be presented on the balance sheet as a direct deduction from the carrying value of the related debt liability. This guidance is to be applied using a retrospective method and is effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2015. Early adoption is permitted. In August 2015, effective upon release, the FASB issued related new authoritative accounting guidance allowing for deferred financing costs associated with line-of-credit arrangements to continue to be presented as assets. The Company is currently evaluating the provisions of this guidance and assessing its impact on the Company's financial statements and disclosures.

In August 2015, the FASB issued new authoritative accounting guidance to defer the effective date of the new revenue recognition standard by one year. The new revenue recognition standard is now effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2017. Early adoption is permitted but only for annual periods, and interim periods within those annual periods, beginning after December 15, 2016. 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, 2015.

3) 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, 2015	December 31, 2014
Beginning asset retirement obligation	$1,133	$ 812
Accretion of discount	35	40
Liabilities incurred	62	310
Liabilities settled	--	(29)
Ending asset retirement obligation	$1,230	$ 1,133
Mineral properties	$200	$ 187
Oil and Gas wells	1,030	946
Ending asset retirement obligation	$1,230	$ 1,133

4) 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 held with a single 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.

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, 2015 are summarized below:

Settlement Period	Counterparty	Basis	Quantity (Bbls/day)	Strike Price	
Crude Oil Costless Collar					
05/01/15 - 12/31/15	Wells Fargo	WTI	500	Put:	$45.00
				Call:	$58.79
Crude Oil Costless Collar					
01/01/16 - 06/30/16	Wells Fargo	WTI	350	Put:	$57.50
				Call:	$66.80
Crude Oil Costless Collar					
07/01/16 - 12/31/16	Wells Fargo	WTI	300	Put:	$50.00
				Call:	$65.25

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 condensed consolidated balance sheet (in thousands):

		As of September 30, 2015 (In thousands)		
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	$1,152	$ (150)	$ 1,002
Crude oil derivative contract	Current liabilities	$150	$ (150)	$ --

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

	(In thousands) Three months ended September 30,		(In thousands) Nine months ended September 30,	
	2015	2014	2015	2014
Realized gain (loss) on risk management activities	$33	$(84)	$(106)	$(616)
Realized gain on risk management activities	$1,337	$780	$1,002	$369
Total realized and unrealized risk management gain (loss)	$1,370	$696	$896	$(247)

5) 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, 2015 and December 31, 2014:

	(In thousands)	Fair Value Measurements at September 30, 2015 Using		
Description	September 30, 2015	(Level 1)	(Level 2)	(Level 3)
Commodity risk management assets	$1,002	$--	$1,002	$--
Available for sale securities	$258	$20	$--	$238
Total assets	$1,260	$20	$1,002	$238
Commodity risk management liability	$--	$--	$--	$--
Executive retirement program liability	786	$--	$--	$786
Total liabilities	$786	$--	$--	$786

		Fair Value Measurements at December 31, 2014 Using		
Description	December 31, 2014	(Level 1)	(Level 2)	(Level 3)
Available for sale securities	$25	$25	$--	$--
Total assets	$25	$25	$--	$--
Executive retirement program liability	$1,309	$--	$--	$1,309
Total liabilities	$1,309	$--	$--	$1,309

Fair Value of Available for Sale Securities

The fair value of shares of Sutter Gold Mining Company is based on quoted market prices obtained from independent pricing services. Accordingly, the Company has classified these instruments as Level 1.

Because Anfield Resources Inc. ("Anfield") is a thinly traded stock, the Company determined that the quoted marked price for Anfield does not equal fair value of the Anfield shares. Pursuant to ASC 820-10-30, the Company used alternate methods, including net present value and management judgement to determine a fair value for the Anfield shares and has classified these instruments as Level 3.

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, 2015, 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 $6.0 million as of September 30, 2015.

6) Debt

Revolving Credit Facility

Energy One, a wholly-owned subsidiary the Company, has in place a credit facility with Wells Fargo Bank, National Association ("Wells Fargo"). As of September 30, 2015, the maximum credit available under the credit facility was $100.0 million and the borrowing base under the facility was $7.0 million.

As of September 30, 2015, the Company had $6.0 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 are in compliance with the covenants under the facility. The current weighted average interest rate on this debt is 2.95% at September 30, 2015.

At September 30, 2015, Energy One was not in compliance with the Current Ratio covenant of the credit facility. On July 16, 2015, the Company entered into a third amendment (the "Third Amendment") to the agreement governing the facility, dated July 30, 2010 (as amended, the "Senior Credit Agreement"), among Energy One, the Company, as guarantor party thereto, the lender parties thereto and

Wells Fargo Bank. The Third Amendment provides for, among other things: (i) a limited waiver with respect to the restricted payments covenant pursuant to which a transfer of $5,000,000 from Energy One to the Company will be permitted in 2015; (ii) a limited waiver of the current ratio covenant as it relates to the fiscal quarters ending June 30, 2015 and September 30, 2015; and (iii) a borrowing base of $7,000,000, subject to further adjustment from time to time in accordance with the Senior Credit Agreement. The foregoing description of the Third Amendment is a summary only and is qualified in its entirety by reference to the Third Amendment, which was attached as an exhibit to the Company's Current Report on Form 8-K filed with the SEC on July 16, 2015.

Because we project that it is unlikely that we will regain compliance with the Current Ratio covenant within the next 12 months, we have reflected the $6.0 million in debt under the credit facility as a current liability as of September 30, 2015 in the applicable balance sheets included in this report. In the event that we are unable to obtain an amendment or waiver of the Senior Credit Agreement to address the anticipated future breaches of the Current Ratio covenant, and other actual or potential future breaches that may occur, the lender under the facility could elect to declare some or all of our debt to be immediately due and payable and could elect to terminate their commitments and cease making further loans.

7) Shareholders' Equity

Common Stock

The following table details the changes in common stock during the nine months ended September 30, 2015:

(Amounts in thousands, except for share amounts)

	Common Stock Shares	Amount	Additional Paid-In Capital
Balance January 1, 2015	28,047,661	$ 280	$ 123,980
Restricted shares activity	303,361	1	33
Stock-based compensation	--	--	331
Balance September 30, 2015	28,351,022	$ 281	$ 124,344

Restricted Stock

The Company grants shares of restricted stock as part of its equity compensation program. Shares of restricted stock are valued at the closing price of the Company's common stock on the grant date and are recognized as general and administrative expense over the vesting period of the award.

During the nine months ended September 30, 2015, the Company granted 340,711 shares of restricted stock under the 2012 Equity and Performance Incentive Plan (the "2012 Equity Plan") to certain employees. The restricted shares vest in equal tranches over three years and had a fair value at issuance of $1.50 per share, which is equal to the closing price of the Company's stock on the date of grant.

100,000 of these restricted shares were immediately vested upon the September 25, 2015 resignation of former CEO, Keith Larsen. Total compensation expense recorded for restricted stock for the three months ended September 30, 2015 and 2014 was $60,000 and $0, respectively. During the nine months ended September 30, 2015 and 2014, we recorded $143,000 and $0, respectively, in compensation expense for restricted stock. As of September 30, 2015, there was $272,000 of total unrecognized compensation expense related to unvested restricted stock awards, which will be amortized through 2017.

A summary of the status and activity of non-vested restricted stock for the nine-month period ended September 30, 2015 is presented in the following table:

	Restricted Shares	Weighted-average grant-date fair value
Non-vested at beginning of year	--	$ --
Granted	340,711	1.22
Vested and issued	(62,650)	0.54
Vested and cancelled	(37,350)	0.54
Non-vested at September 30, 2015	240,711	$ 1.50

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, 2015:

	Employee Stock Options		Director Stock Options	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
Outstanding balance at December 31, 2014	2,097,413	$ 3.82	178,666	$ 3.28
Granted	340,711	$ 1.50	--	$ --
Forfeited	--	$ --	--	$ --
Expired	--	$ --	--	$ --
Exercised	--	$ --	--	$ --
Outstanding at September 30, 2015	2,438,124	$ 3.50	178,666	$ 3.28
Exercisable at September 30, 2015	2,167,413	$ 3.74	129,666	$ 3.21
Weighted Average Remaining Contractual Life - Years		3.77		7.14
Aggregate intrinsic value of options outstanding ($ Thousands)		$ --		$ --

Employee Stock Options. During the nine months ended September 30, 2015, we issued 340,711 options to certain employees under the 2012 Equity Plan. The options were issued at the closing price of $1.50 on the date of grant, vest over a three year period and expire ten years from the date of grant. 100,000 of these options were immediately vested upon the September 25, 2015 resignation of former CEO, Keith Larsen. These options were valued under the Black-Scholes pricing model using a risk free interest rate of 1.765%, expected life of six years and expected volatility of 63.3585%. During the three months ended September 30, 2015 and 2014, we recorded $34,000 and $106,000, respectively, in compensation expense for employee stock options. During the nine months ended September 30, 2015 and 2014, we recorded $138,000 and $192,000, respectively, in compensation expense for employee stock options. As of September 30, 2015, there was $186,000of total unrecognized compensation cost related to employee stock options, which is expected to be amortized over a weighted average period of 2.00 years.

Director Stock Options. During the three months ended September 30, 2015 and 2014, we recorded $14,000 and $15,000, respectively, in expense for options issued to non-employee directors. During the nine months ended September 30, 2015 and 2014, we recorded $50,000 and $75,000, respectively, in expense for options issued to non-employee directors. As of September 30, 2015, there was $97,000 of total unrecognized compensation cost related to director stock options, which is expected to be amortized over a weighted average period of 1.85 years.

8) 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 occurrences such as major acquisitions, divestitures, commodity 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 2015 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, 2015, 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.

9) Segment Information

As of September 30, 2015, 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, 2015 and 2014, and total assets as of September 30, 2015 and December 31, 2014 by segment, are as follows:

	(In thousands) For the three months ended September 30,		(In thousands) For the nine months ended September 30,	
	2015	2014	2015	2014
Revenues:				
Oil and gas	$2,622	$9,928	$8,586	$27,312
Total revenues	2,622	9,928	8,586	27,312
Operating expenses:				
Oil and gas	25,187	7,649	56,437	19,084
Mineral properties	835	930	2,295	2,344
Total operating expenses	26,022	8,579	58,732	21,428
Interest expense:				
Oil and gas	56	93	201	307
Mineral properties	--	--	--	--
Total interest expense	56	93	201	307
Operating income (loss)				
Oil and gas	$(22,621)	$2,186	$(48,052)	$7,921
Mineral properties	(835)	(930)	(2,295)	(2,344)
Operating income (loss) from identified segments	(23,456)	1,256	(50,347)	5,577
General and administrative expenses	(1,824)	(2,030)	(4,524)	(5,169)
Add back interest expense	56	93	201	307
Other revenues and expenses	1,573	618	1,036	(472)
Income (loss) before income taxes	$(23,651)	$(63)	$(53,634)	$243
Depreciation depletion and amortization expense:				
Oil and gas	$2,176	$4,621	$7,105	$11,498
Mineral properties	31	31	93	92
Corporate	36	37	108	112
Total depreciation depletion amortization expense	$2,243	$4,689	$7,306	$11,702

-23-

	(In thousands)	
	September 30, 2015	December 31, 2014
Assets by segment		
Oil and gas	$43,389	$92,020
Mineral	21,944	21,942
Corporate	6,169	9,561
Total assets	$71,502	$123,523

10) 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) and unvested restricted stock. The treasury stock method is used to measure the dilutive impact of unvested restricted stock and 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):

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
Net (loss) income	$(23,651)	$(63)	$(53,634)	$243
Basic weighted-average common shares outstanding	28,051,066	27,899,505	28,048,808	27,808,231
Add: dilutive effect of stock options	--	--	--	392,157
Add: dilutive effect of unvested restricted stock	--	--	--	--
Diluted weighted-average common shares outstanding	28,051,066	27,899,505	28,048,808	28,200,388
Basic net (loss) income per share	$(0.84)	$(0.00)	$(1.91)	$0.01
Diluted net (loss) income per share	$(0.84)	$(0.00)	$(1.91)	$0.01

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

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
Weighted-average anti-dilutive stock options	2,616,790	1,067,341	2,615,542	1,059,176
Weighted-average anti-dilutive restricted stock awards	334,189	--	239,829	--
	2,950,979	1,067,341	2,855,371	1,059,176

11) Commitments and Contingencies

Legal Proceedings

From time to time, we are party to certain legal actions and claims arising in the ordinary course of business. While the outcome of these events cannot be predicted with certainty, management does not expect these matters to have a materially adverse effect on our financial position or results of operations. Following are currently pending legal matters:

Water Rights Litigation –Mt. Emmons Project

On July 25, 2008, we filed an Application for Finding of Reasonable Diligence with the Colorado Water Court ("Water Diligence Application") concerning the conditional water rights associated with the Mt. Emmons Project (Case No. 2008CW81). The conditional water decree ("Decree") required the Company to file its proposed plan of operations and associated permits with the Forest Service and BLM within six years of entry of the Decree, or within six years of the final determination of the pending patent application, whichever occurred later. The BLM issued the mineral patents on April 2, 2004. Although the issuance of the patents was appealed, on April 30, 2007, the United States Supreme Court made a final determination (by denial of certiorari) upholding BLM's issuance of the mineral patents. The Company filed a plan of operations on March 31, 2010. On April 20, 2015, the Colorado Water Court entered a decree granting the Water Diligence Application. The decree continues the conditional water rights for a six-year period and requires the Company to submit a new Application for Finding of Reasonable Diligence in April 2021 if the water rights have not been applied to a beneficial use by that time.

Quiet Title Action – Dimmit County, TX

On October 4, 2013, Dimmit Wood Properties, Ltd. ("Dimmit") filed a quiet title, breach of contract, and trespass action against Chesapeake Exploration, LLC ("Chesapeake"), Crimson Exploration Operating, Inc. ("Crimson"), EXCO Operating Company, LP, OOGC America, Inc., Energy One and Liberty Energy, LLC ("Liberty") (jointly referred to as "Defendants") concerning an 800.77 gross acre oil and gas lease ("Lease") located in Dimmit County, Texas. Crimson, Energy One and Liberty received an assignment from Chesapeake of the Lease, in which Energy One has a 30% working interest. Dimmit alleged that the Lease terminated due to the failure to achieve production in paying quantities and for having non-existent production for allegedly significant time periods. On April 27, 2015, the Company, Crimson and Liberty agreed to settle the action. In accordance with the settlement agreement, the Company received $1.5 million in exchange for releasing its interest in the Lease. The settlement agreement does not affect a similar case involving Dr. Darrell Willerson, Sue Willerson and Willerson Energy Partners, L.P.

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 nine months ended September 30, 2015 and 2014. 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, 2014 (the "2014 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 plan to move our headquarters from Riverton, Wyoming to Denver, Colorado, and have experienced management turnover in connection with this move. Managing this transition will be an area of significant focus for us for the near term.

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 in the process of developing operational capabilities and expect to pursue opportunities to acquire operated properties and/or operatorship of existing properties.

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, 2015 and December 31, 2014 were as follows:

	(In thousands)	
	September 30, 2015	December 31, 2014
Proved oil and gas properties	$30,187	$75,724
Unproved oil and gas properties	8,196	10,188
Exploratory wells in progress	--	2,357
Undeveloped mining properties	21,942	21,942
	$60,325	$110,211

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, although currently depressed commodity prices have

-26-

had and will likely continue to have an adverse effect on the level of drilling activity. 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, 2015 and 2014.

	September 30,			
	2015		2014	
	Gross	Net[(1)]	Gross	Net[(1)]
Williston Basin:				
Productive wells	109.00	10.33	94.00	10.18
Wells being drilled or awaiting completion	7.00	0.01	6.00	0.09
South Texas:				
Productive wells	37.00	9.99	33.00	8.89
Wells being drilled or awaiting completion	--	--	2.00	0.63
Gulf Coast:				
Productive wells	3.00	0.56	3.00	0.56
Wells being drilled or awaiting completion	--	--	--	--
Total:				
Productive wells	149.00	20.88	130.00	19.63
Wells being drilled or awaiting completion	7.00	0.01	8.00	0.72

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

Williston Basin, North Dakota

Our net investment in Williston Basin, North Dakota wells was $212,000 during the nine months ended September 30, 2015.

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, 2015, we have drilled and completed 24 gross (6.39 net) Bakken formation wells and two gross (0.22 net) Three Forks formation wells under our Drilling Participation Agreement with Statoil. 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, 2015, we have drilled and completed 44 gross (3.11 net) Bakken formation wells and nine gross (0.33 net) Three Forks formation wells in these prospects. The wells are operated by Zavanna (18 gross, 2.91 net), Emerald Oil, Inc. (30 gross, 0.35 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 2015, we completed three gross (0.01 net) wells in the Yellowstone and SEHR prospects.

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, 2015, there were 30 gross (0.25 net) producing wells in the remaining 15 drilling units. At September 30, 2015, 7 additional gross (0.01 net) wells had been spud and were in progress.

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, 2015, we have 31 gross (8.36 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. The wells are operated by Contango (28 gross, 8.08 net), WCS Oil & Gas Corporation (2 gross, 0.15 net) and CML Exploration (1 gross, 0.13 net). Our net investment in these wells during the first nine months of 2015, including lease acquisition and holding costs in the prospects, was $1.3 million.

Big Wells Prospect.   We participate in the Big Wells prospect with U.S. Enercorp. At September 30, 2015, we have two gross (0.30 net) producing Buda limestone wells in this prospect.

Carrizo Creek and South McKnight Prospects. We participate in the Carrizo Creek and South McKnight prospects with U.S. Enercorp. At September 30, 2015, we have four gross (1.33 net) producing wells in these prospects. Our net investment in this acreage and wells during the nine months ended September 30, 2015 was $1.0 million.

Onshore U.S. Gulf Coast

We participate with three different operators in the onshore U.S. Gulf Coast area. At September 30, 2015, we had three gross (0.56 net) producing wells in this region.

2015 Production Results

The following table provides a regional summary of our net production during the first nine months of 2015:

	Williston Basin	South Texas	Gulf Coast	Total
First Nine Months of 2015 Production				
Oil (Bbl)	129,010	44,259	43	173,312
Gas (Mcf)	66,297	115,377	138,819	320,493
NGLs (Bbl)	10,440	11,350	--	21,790
Equivalent (BOE)	150,500	74,838	23,180	248,518
Avg. Daily Equivalent (BOE/d)	551	274	85	910
Relative percentage	60.6 %	30.1 %	9.3 %	100 %

Uranium Properties

On June 30, 2015, the Company entered into Amendment No. 1 to the Amendment Assignment and Assumption Agreement dated as of August 14, 2014. As amended, conditioned upon the closing of a purchase and sale transaction between Anfield Resources Inc. ("Anfield") and Uranium One Inc. ("Uranium One") (the "Anfield-Uranium One Transaction"), 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. $750,000 in Anfield common shares upon closing of the Anfield-Uranium One Transaction;
2. $750,000 in Anfield common shares on the first anniversary of the closing of the Anfield-Uranium One Transaction;

3. $1.0 million in Anfield common shares on the second anniversary of the closing of the Anfield-Uranium One Transaction;
4. $2.5 million in cash paid upon 18 months of continuous commercial production; and
5. $2.5 million in cash paid upon 36 months of continuous commercial production.

If any of the share issuances result in the Company holding in excess of 20% of the then issued and outstanding shares of Anfield (the "Threshold"), such shares in excess of the Threshold will not be issued at that time, but will be deferred to the next scheduled share issuance. If, upon the final scheduled share issuance the number of shares to be issued exceeds the Threshold, the value in excess of the Threshold shall be paid to the Company in cash.

The Anfield-Uranium One Transaction closed on September 1, 2015, and as a result, the Company received 7,436,505 shares of Anfield valued at $750,000 using a 10 day volume-weighted average closing price for Anfield shares as of that date. Pursuant to ASC 820-10-30, the Company determined that because Anfield is a thinly traded stock, the transaction price of $750,000 did not equal the fair value of the Anfield shares. Accordingly, the Company used alternate methods to determine a fair value for the Anfield shares and established a fair value of $238,000 at both initial measurement and as of September 30, 2015. There can be no guarantee of the future value of Anfield shares received or when, if ever, commercial production will commence.

Mount Emmons Molybdenum Project

With respect to the Mount Emmons project, the Company expects to continue its scoping analysis of the Mine Plan of Operations with the U.S. Forest Service through the balance of 2015.

Additional Comparative Data

The following table provides information regarding selected production and financial information for the quarter ended September 30, 2015 and the immediately preceding three quarters.

	For the Three Months Ended			
	September 30, 2015	June 30, 2015	March 31, 2015	December 31, 2014
	(in thousands, except for production data)			
Production (BOE)	80,673	81,618	86,227	101,265
Oil, gas and NGL production revenue	$2,622	$3,285	$2,679	$5,067
Unrealized and realized derivative gain (loss)	$33	$(297)	$(177)	$829
Impairment of oil and gas properties	$21,446	$3,208	$19,240	$--
Lease operating expense	$1,324	$1,716	$1,594	$2,585
Production taxes	$241	$305	$258	$467
DD&A	$2,176	$2,055	$2,874	$3,187
General and administrative	$1,824	$1,221	$1,479	$1,390
Mineral holding costs	$365	$252	$295	$166
Water treatment plant	$470	$455	$458	$475
Income (loss)	$(23,669)	$(6,280)	$(23,703)	$(2,334)

Results of Operations

Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014

During the three months ended September 30, 2015, we recorded a net loss after taxes of $23.7 million, or $0.84 per share basic and diluted, as compared to a net loss after taxes of $63,000, or $0.00 per share basic and diluted, during the same period of 2014.

Oil and Gas Operations. Oil and gas operations generated an operating loss of $22.6 million during the quarter ended September 30, 2015 as compared to operating income of $2.3 million during the quarter ended September 30, 2014. The following table summarizes production volumes, average sales prices and operating revenues for the three months ended September 30, 2015 and 2014:

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Increase (Decrease)
Production volumes			
Oil (Bbls)	56,084	98,274	(42,190)
Natural gas (Mcf)	107,952	197,217	(89,265)
Natural gas liquids (Bbls)	6,597	11,341	(4,744)
Equivalent (BOE)	80,673	142,484	(61,811)
Avg. Daily Equivalent (BOE/d)	877	1,549	(672)
Average sales prices			
Oil (per Bbl)	$40.26	$88.35	$(48.09)
Natural gas (per Mcf)	2.60	4.41	(1.81)
Natural gas liquids (per Bbl)	12.58	33.15	(20.57)
Equivalent (BOE)	32.50	69.68	(37.18)
Operating revenues (in thousands)			
Oil	$2,258	$8,682	$(6,424)
Natural gas	281	870	(589)
Natural gas liquids	83	376	(293)
Total operating revenue	2,622	9,928	(7,306)
Oil and gas production expense	(1,324)	(2,238)	914
Production taxes	(241)	(790)	549
Impairment	(21,446)	--	(21,446)
Income before depreciation, depletion and amortization	(20,389)	6,900	(27,289)
Depreciation, depletion and amortization	(2,176)	(4,621)	2,445
Income	$(22,565)	$2,279	$(24,844)

During the three months ended September 30, 2015, we produced 80,673 BOE, or an average of 877 BOE/d, as compared to 142,484 BOE or 1,549 BOE/d during the three months ended September 30, 2014. In our South Texas region, production decreased 69%, from 73,531 BOE to 22,911 BOE as a result of normal production declines and fewer wells being drilled due to low commodity prices. Production in our Bakken region decreased 19%, from 61,305 BOE to 49,578 BOE, as a result of normal production declines. 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 $2.6 million in revenues during the three months ended September 30, 2015 as compared to $9.9 million during the same period in 2014. The $7.3 million decrease in revenue is primarily due to lower oil and gas prices and lower oil and gas sales volumes in the third quarter of 2015 as compared to the third quarter of 2014.

Our average net realized price (operating revenue per BOE) for the three months ended September 30, 2015 was $32.50 per BOE compared with $69.68 per BOE for the same period in 2014. Due to takeaway constraints, the discount to West Texas Intermediate ("WTI") quoted prices, or differential, for oil prices in the Williston Basin ranged from $11.45 to $14.35 per barrel during the three months ended September 30, 2015. 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 $1.3 million for the three months ended September 30, 2015 was comprised of $1.2 million in lease operating expense and $127,000 in workover expense.

During the three months ended September 30, 2015, the Company recorded a proved property impairment of $21.4 million related to its oil and gas assets. The impairment was primarily due to the decline in the price of oil. There were no proved property impairments recorded during the three months ended September 30, 2014.

Our depletion, depreciation and amortization (DD&A) rate for the three months ended September 30, 2015 was $26.98 per BOE compared to $32.44 per BOE for the same period in 2014. 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 $470,000 in costs and expenses for the water treatment plant and $365,000 for holding costs for the Mt. Emmons molybdenum property during the three months ended September 30, 2015. During the three months ended September 30, 2014, we recorded $491,000 in operating costs related to the water treatment plant and $439,000 in holding costs.

General and Administrative Expenses. General and administrative expenses decreased by $206,000 during the three months ended September 30, 2015 compared to general and administrative expenses for the three months ended September 30, 2014. The decrease in general and administrative costs in 2015 is primarily a result of:

- $874,000 reduction in executive retirement expense. The reduction during the three months ended September 30, 2015 was due in part to the extinguishment of accrued retirement liability of $344,000 upon the resignation of Chief Executive Officer, Keith Larsen. This reduction compares to an increase of $530,000 during the three months ended September 30, 2014 due the acceleration of executive retirement expense related to the retirement of former President, Mark Larsen;
- $106,000 reduction in compensation expenses;
- $68,000 reduction in professional services;

· $68,000 reduction in contract services; and
· $18,000 reduction in other general and administrative costs.

These amounts were partially offset by increases in severance expenses of $748,000 and bad debt expense of $180,000. The increase in severance expenses to $948,000 resulted from the resignations of the Chief Executive Officer, Chief Financial Officer, Principal Accounting Officer and other employees who have elected not to move with the Company to Denver, Colorado. During the three months ended September 30, 2014, severance expenses consisted of $200,000 paid to the former General Counsel.

The following table details the changes in the Company's general and administrative costs for the three months ended September 30, 2015 compared to the three months ended September 30, 2014:

	(In thousands) For the three months ended September 30,		
	2015	2014	Change
Executive retirement	(344)	530	(874)
Compensation expense	649	755	(106)
Professional services	86	154	(68)
Contract services	75	143	(68)
Severance expenses	948	200	748
Bad debt expense	180	--	180
Director's fees	69	74	(5)
Other costs	161	174	(13)
Total general and administrative costs	$1,824	$2,030	$ (206)

Other Income and Expenses. We recognized an unrealized and realized derivative gain of $1.4 million in the third quarter of 2015 compared to a gain of $696,000 for the same period in 2014. The 2015 amount includes a gain on unrealized changes in the fair value of our commodity derivative contracts of $1.3 million and realized cash settlement gains on derivatives of $33,000.

Interest income was 66,000 during the quarter ended September 30, 2015 and $1,000 during the quarter ended September 30, 2014.

Interest expense decreased to $67,000 during the quarter ended September 30, 2015 from $69,000 during the quarter ended September 30, 2014.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014

During the nine months ended September 30, 2015, we recorded a net loss after taxes of $53.7 million, or $1.91 per share basic and diluted, as compared to net income after taxes of $243,000, or $0.01 per share basic and diluted, during the same period of 2014.

Oil and Gas Operations. Oil and gas operations generated an operating loss of $47.9 million during the nine months ended September 30, 2015 as compared to operating income of $8.2 million during the nine months ended September 30, 2014. The following table summarizes production volumes, average sales prices and operating revenues for the nine months ended September 30, 2015 and 2014:

	Nine Months Ended September 30, 2015	2014	Increase (Decrease)
Production volumes			
Oil (Bbls)	173,312	265,051	(91,739)
Natural gas (Mcf)	320,493	452,559	(132,066)
Natural gas liquids (Bbls)	21,790	23,599	(1,809)
Equivalent (BOE)	248,518	364,076	(115,559)
Avg. Daily Equivalent (BOE/d)	910	1,334	(424)
Average sales prices			
Oil (per Bbl)	$43.21	$91.32	$(48.11)
Natural gas (per Mcf)	2.75	4.91	(2.16)
Natural gas liquids (per Bbl)	9.91	37.46	(27.55)
Equivalent (BOE)	34.55	75.02	(40.47)
Operating revenues (in thousands)			
Oil	$7,489	$24,205	$(16,716)
Natural gas	881	2,223	(1,342)
Natural gas liquids	216	884	(668)
Total operating revenue	8,586	27,312	(18,726)
Oil and gas production expense	(4,634)	(5,295)	661
Production taxes	(804)	(2,291)	1,487
Impairment	(43,894)	--	(43,894)
Income before depreciation, depletion and amortization	(40,746)	19,726	(60,472)
Depreciation, depletion and amortization	(7,105)	(11,498)	4,393
Income	$(47,851)	$8,228	$(56,079)

During the nine months ended September 30, 2015, we produced 248,518 BOE, or an average of 910 BOE/d, as compared to 364,076 BOE or 1,334 BOE/d during the nine months ended September 30, 2014. In our South Texas region, production decreased 53%, from 159,195 BOE to 74,838 BOE as a result of normal production declines and fewer wells being drilled due to low commodity prices. Production in our Bakken region decreased 18%, from 182,451 BOE to 150,500 BOE, as a result of normal production declines. 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 $8.6 million in revenues during the nine months ended September 30, 2015 as compared to $27.3 million during the same period in 2014. The $18.7 million decrease in revenue is primarily due to lower oil and gas prices and lower oil and gas sales volumes in the first nine months of 2015 as compared to the first nine months of 2014.

Our average net realized price (operating revenue per BOE) for the nine months ended September 30, 2015 was $34.55 per BOE compared with $75.02 per BOE for the same period in 2014. Due to takeaway constraints, the discount to West Texas Intermediate ("WTI") quoted prices, or differential, for oil prices in the Williston Basin ranged from $11.45 to $16.50 per barrel during the nine months ended

September 30, 2015. 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 $4.6 million for the nine months ended September 30, 2015 was comprised of $4.1 million in lease operating expense and $516,000 in workover expense.

During the nine months ended September 30, 2015, the Company recorded proved property impairments totaling $43.9 million related to its oil and gas assets. The impairments were primarily due to the decline in the price of oil. There were no proved property impairments recorded during the first nine months of 2014.

Our depletion, depreciation and amortization (DD&A) rate for the nine months ended September 30, 2015 was $28.49 per BOE compared to $31.58 per BOE for the same period in 2014. 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 $912,000 for holding costs for the Mt. Emmons molybdenum property during the nine months ended September 30, 2015. During the nine months ended September 30, 2014, we recorded $1.4 million in operating costs related to the water treatment plant and $944,000 in holding costs.

General and Administrative Expenses. General and administrative expenses decreased by $645,000 during the nine months ended September 30, 2015 compared to general and administrative expenses for the nine months ended September 30, 2014. The decrease in general and administrative costs in 2015 is primarily a result of:

- $890,000 reduction in executive retirement expense. The reduction during the nine months ended September 30, 2015 was due to the extinguishment of accrued retirement liability of $344,000 upon the resignation of Chief Executive Officer, Keith Larsen. This reduction compares to an increase of $530,000 during the nine months ended September 30, 2014 due the acceleration of executive retirement expense related to the retirement of former President, Mark Larsen;
- $379,000 reduction in professional services;
- $134,000 reduction in compensation expenses;
- $107,000 reduction in contract services; and
- $63,000 reduction in other general and administrative costs and director's fees.

These amounts were partially offset by increases in severance expenses of $748,000 and bad debt expense of $180,000. The increase in severance expenses to $948,000 resulted from the resignations of the Chief Executive Officer, Chief Financial Officer, Principal Accounting Officer and other employees who have elected not to move with the Company to Denver, Colorado. During the nine months ended September 30, 2014, severance expenses consisted of $200,000 paid to the former General Counsel.

The following table details the changes in the Company's general and administrative costs for the nine months ended September 30, 2015 compared to the nine months ended September 30, 2014:

	(In thousands) For the nine months ended September 30,		
	2015	2014	Change
Executive retirement	(314)	576	(890)
Professional services	406	785	(379)
Compensation expense	2,203	2,337	(134)
Contract services	295	402	(107)
Severance expense	948	200	748
Bad debt expense	180	--	180
Director's fees	239	236	3
Other costs	567	633	(66)
Total general and administrative costs	$4,524	$5,169	$ (645)

Other Income and Expenses. We recognized an unrealized and realized derivative gain of $896,000 in the first nine months of 2015 compared to a loss of $247,000 for the same period in 2014. The 2015 amount includes a gain on unrealized changes in the fair value of our commodity derivative contracts of $1.0 million and realized cash settlement losses on derivatives of $106,000.

During the nine months ended September 30, 2015, we recorded a $57,000 gain from the sale of assets. During the nine months ended September 30, 2014, we recorded a gain on the sale of assets of $28,000.

Interest income was $68,000 during the nine month period ended September 30, 2015 and $3,000 during the nine months ended September 30, 2014.

As a result of lower average debt balances, interest expense decreased to $196,000 during the nine months ended September 30, 2015 from $314,000 during the nine months ended September 30, 2014.

Overview of Liquidity and Capital Resources

At September 30, 2015, we had $3.9 million in cash and cash equivalents and our working capital deficit (current assets minus current liabilities) was $9.2 million. As discussed below in "Capital Resources and Capital Requirements", we project that our capital resources at September 30, 2015 will be sufficient to fund our operations and capital projects through the balance of 2015. Given the size of our potential commitments related to our existing inventory of drilling projects, however, our requirements for capital could increase significantly 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, 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 availability of any such sources of additional financing could be adversely affected by the current commodity price environment.

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.

-35-

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. The dramatic decline in oil and natural gas prices experienced in late 2014, and continued low prices to date in 2015, has affected our ability to maintain adequate liquidity, satisfy our obligations under our revolving credit facility and pay costs associated with the Mt. Emmons project.

Capital Resources

Primary potential sources of future liquidity include the following:

Oil and Gas Production. At September 30, 2015, we had 149 gross (20.88 net) producing wells. During the nine months ended September 30, 2015, we received an average of $954,000 per month from these producing wells with an average operating cost of $515,000 per month (including workover costs) and production taxes of $89,000, for average net cash flows of $350,000 per month from oil and gas production before non-cash depletion expense. We anticipate that average cash flows from oil and gas operations through the balance of 2015 will approximate average cash flows for the first nine months of 2015. 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 wells with current partners and with 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, 2015, we had $3.9 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. As of the date of this report, the commitment amount is $100 million and the borrowing base is $7.0 million.

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.

Energy One is required to comply with customary affirmative covenants and with certain negative covenants. The principal negative financial covenants (measured at various times as provided in the Credit Agreement) do not permit (i) the Interest Coverage Ratio (Interest Expense to EBITDAX) to be less than 3.0 to 1; (ii) Total Debt to EBITDAX to be greater than 3.5 to 1; and (iii) the Current Ratio (current assets plus unused lender commitments under the Borrowing Base) to be less than 1.0 to 1.0. EBITDAX is defined in the Credit Agreement as Consolidated Net Income, plus non-cash charges. The restricted payments covenant in the agreement also limits Energy One's ability to make distributions to the Company.

If Energy One fails to pay interest or principal when due, or fails to comply with the covenants in the Credit Agreement (after a reasonable cure period, if applicable), Wells Fargo as Administrative Agent may (and shall, if requested by lenders holding not less than 2/3rds of the outstanding loan principal), declare the loans immediately due, and foreclose on Energy One's assets and enforce the Company's guaranty.

At September 30, 2015, Energy One was in breach of the Current Ratio covenant under the credit facility. On July 16, 2015, Energy One entered into an amendment to the credit facility that, among other things, (i) provided a limited waiver with respect to the restricted payments covenant pursuant to which a transfer of $5,000,000 from Energy One to the Company will be permitted in 2015; (ii) provided a limited waiver of the Current Ratio covenant as it relates to the fiscal quarters ending June 30, 2015 and September 30, 2015; and (iii) reduced the borrowing base to $7,000,000, subject to further adjustment from time to time in accordance with the agreement.

If oil prices continue to remain depressed through the end of 2015, we may not be able to borrow additional funds under the facility due to non-compliance with covenants and/or borrowing base limitations. Additionally, Energy One is restricted from transferring funds to the Company if the amount borrowed under the facility exceeds 80% of the borrowing base, or if a borrowing base deficiency, default or event of default exists or would exist after such payment. In the short term, we believe that the Company has sufficient funds to meet its obligations, but in the longer term, this restriction could cause cash shortfalls for the Company.

In the event that we are unable to obtain further amendments to, or waivers of, covenants under the revolving credit facility to address potential future breaches that may occur, the lenders could elect to declare some or all of our debt to be immediately due and payable and could elect to terminate their commitments and cease making further loans.

As of the date of this report, we have outstanding borrowings of $6.0 million under the credit facility.

Capital Requirements

Our direct capital requirements during the balance of 2015 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 2015 capital expenditure plan primarily from the sources described above under "Capital Resources". We may be required to reduce or defer part of our 2015 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, 2015, we have spent approximately $2.6 million of our $8.2 million 2015 oil and gas capital expenditure budget. The remaining $5.6 million is currently budgeted to be spent on exploration and acquisition initiatives in South Texas and in the Williston Basin of North Dakota. However, due to the significant decline in the price of oil, most of the anticipated 2015 drilling projects have been suspended and we are therefore likely to invest less than the budgeted amount for the year. As of the date of this report, we expect to complete the 14 gross (0.02 net) wells that were drilled and awaiting completion at September 30, 2015. No additional 2015 drilling is currently scheduled. If all drilling activities remain suspended through the end of the year, we anticipate that our capital expenditures for the fourth quarter will be approximately

$175,000. Actual capital expenditures for each regional drilling program are contingent upon timing, well costs and success. If any of our drilling initiatives are not initially successful or progress slower 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. US Energy Corp continues to explore multiple options for an economically beneficial disposition of the mine during this extended period of abnormally low commodity prices including a molybdenum price of $5.25/lb. As the price of molybdenum continues to be well below the cost to extract the mineral commercially alternative plans to subsidize the ongoing cost to maintain the rights to the resource and to operate the facilities are being considered. We are responsible for all costs associated with the Mt. Emmons project, which includes regulatory compliance and the operation of a water treatment plant. Operating costs for the water treatment plant during the remainder of 2015 are expected to be approximately $142,000 per month and holding costs related to the mine are expected to average $66,000 per month. Falling commodity prices and resulting decreases in our oil and gas revenue have made it more difficult for us to continue bearing these costs. Costs associated with the potential closing of the mine and/or the near term maintenance could be substantial due to increasing state and federal scrutiny of mining operations and the increased standards. Although we believe that the project may have considerable value if molybdenum prices improve, we may attempt to create offsetting developments or transfer the project and the associated environmental obligations to another party. Such outcomes may involve the payment of consideration by USEG in exchange for the other party's assumption of those obligations. We can provide no assurance that any transfer will be completed on the terms we expect or at all.

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 $1.0 million related to our oil and gas wells and $200,000 related to the Mt. Emmons molybdenum property. No reclamation is expected to be performed in 2015 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, 2015

The following table presents changes in cash flows between the nine month periods ended September 30, 2015 and 2014. 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,		
	2015	2014	Change
Net cash provided by operating activities	$1,246	$14,130	$(12,884)
Net cash (used in) investing activities	(1,359)	(14,567)	13,208
Net cash (used in) financing activities	(20)	(1,055)	1,035

Operating Activities. Cash provided by operations for the nine month period ended September 30, 2015 decreased to $1.2 million as compared to cash provided by operations of $14.1 million for the same period of 2014. This $12.9 million year over year decrease in cash from operating activities is primarily due to lower oil and gas revenue, partially offset by lower oil and gas operating expenses during the nine months ended September 30, 2015 as compared to the nine months ended September 30, 2014. 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, 2015, investing activities consumed cash through the acquisition and development of oil and gas properties in the amount of $3.9 million, the acquisition of equipment in the amount of $4,000 and a net change of $885,000 in restricted investments. During this period, investing activities provided $136,000 in cash from the sale of non-oil and gas related properties and used equipment.

The $13.2 million change in investing activities during the nine months ended September 30, 2015 as compared to the same period of 2014 is primarily a result of: (a) a $21.0 million decrease in expenditures for acquisitions and development of oil and gas, (b) an $11.5 million decrease in the proceeds from the sale of oil and gas properties, as there were no such sales during the nine months ended September 30, 2015, (c) a $1.5 million increase from the settlement of a lawsuit, (d) a $1.2 million decrease in acquisitions of properties and equipment, (e) $136,000 in proceeds from the sale of property and equipment in 2015 as compared to $28,000 during the 2014 period, and (f) a $936,000 decrease in the balance of restricted investments.

Financing Activities. During the nine months ended September 30, 2015, financing activities used $20,000 from the cancellation of 37,350 shares valued at $0.54 per share. The shares were canceled for the payment of taxes related to the vesting of restricted shares. During the nine months ended September 30, 2014, financing activities used $1.1 million relating to the repayment of borrowings under our credit facility and $55,000 from the payment of taxes related to stock option exercises.

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 2014 10-K (please see pages 69 to 72).

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.

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 present acquisition opportunities 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, 2015, 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 future transactions. 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 2014 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 permitting 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 scope, productivity and economic potential than the mine contemplated in 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 and financial risks.

Off-Balance Sheet Arrangements

None

Contractual Obligations

We had three principal categories of contractual obligations at September 30, 2015: Debt to third parties of $6.0 million, executive retirement obligations of $786,000 and asset retirement obligations of $1.2 million.

The debt to third parties consists of $6.0 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 are 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 31 years.

-40-

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 from time to time. 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 the date of this report are summarized below:

Settlement Period	Counterparty	Basis	Quantity (Bbls/day)	Strike Price	
Crude Oil Costless Collar					
05/01/15 - 12/31/15	Wells Fargo	WTI	500	Put:	$45.00
				Call:	$58.79
Crude Oil Costless Collar					
01/01/16 - 06/30/16	Wells Fargo	WTI	350	Put:	$57.50
				Call:	$66.80
Crude Oil Costless Collar					
07/01/16 - 12/31/16	Wells Fargo	WTI	300	Put:	$50.00
				Call:	$65.25

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 a gain (loss) on risk management activities, net in our consolidated statements of operations. For further details regarding our derivative contracts, please refer to Note 4, 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, 2015, 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, 2015 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

There have been no material changes from the legal proceedings as previously disclosed in our Quarterly Report on Form 10-Q for the period ended June 30, 2015 (page 44).

ITEM 1A. Risk Factors

There have been no material changes from the risk factors as previously disclosed in our Quarterly Report on Form 10-Q for the period ended June 30, 2015 (pages 44-45) and in the 2014 10-K (pages 13-30).

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
10.1	Severance Agreement
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, 2015 By: /s/ David A. Veltri
DAVID A. VELTRI
CEO, COO and President

Date: November 7, 2015 By: /s/ Steven D. Richmond
STEVEN D. RICHMOND
Chief Financial Officer