US ENERGY CORP
Form 10-Q
August 09, 2012

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

x Quarterly report pursuant to section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarter ended June 30, 2012 or

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

Commission File Number: 0-6814

U.S. ENERGY CORP.
(Exact name of registrant as specified in its charter)

Wyoming (State or other jurisdiction of incorporation or organization)	83-0205516 (I.R.S. Employer Identification No.)
877 North 8th West, Riverton, WY (Address of principal executive offices)	82501 (Zip Code)
Registrant's telephone number, including area code:	(307) 856-9271
Not Applicable (Former name, address and fiscal year, if changed since last report)	

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Company was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
YES x NO o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

YES x NO o

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

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

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

YES o NO x

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

At August 6, 2012 there were issued and outstanding 27,475,978 shares of the Company’s common stock, $0.01 par value.

U.S. ENERGY CORP. and SUBSIDIARIES

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PART I. FINANCIAL INFORMATION

ITEM 1. Financial Statements

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

	June 30, 2012	December 31, 2011
Current assets:		
Cash and cash equivalents	$3,882	$12,874
Available for sale securities	221	166
Accounts receivable		
Trade	5,943	5,496
Income taxes	9	113
Commodity risk management asset	1,112	3
Assets held for sale	16,180	18,132
Other current assets	360	352
Total current assets	27,707	37,136
Investment	2,472	2,623
Properties and equipment		
Oil & gas properties under full cost method,		
net of $36,231 and $28,561 accumulated		
depletion, depreciation and amortization	85,599	90,942
Undeveloped mining claims	20,739	20,739
Property, plant and equipment, net	8,977	9,196
Net properties and equipment	115,315	120,877
Other assets	1,789	1,803
Total assets	$147,283	$162,439

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)

	June 30, 2012	December 31, 2011
Current liabilities:		
Accounts payable	$3,718	$9,370
Accrued compensation	418	501
Commodity risk management liability	--	601
Current portion of debt	200	200
Liabilities held for sale	10,208	10,241
Other current liabilities	41	24
Total current liabilities	14,585	20,937
Long-term debt, net of current portion	5,200	12,200
Deferred tax liability	425	1,189
Asset retirement obligations	619	510
Other accrued liabilities	795	822
Commitment and contingencies		
Shareholders' equity		
Common stock, $.01 par value; unlimited shares		
authorized; 27,460,978 and 27,409,908		
shares issued, respectively	275	274
Additional paid-in capital	122,707	122,523
Accumulated surplus	2,536	3,906
Unrealized gain on marketable securities	141	78
Total shareholders' equity	125,659	126,781
Total liabilities and shareholders' equity	$147,283	$162,439

The accompanying notes are an integral part of these statements.

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

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	2012	2011
Oil, gas, and NGL production revenues:	$8,522	$7,025	$16,857	$13,704
Operating expenses:				
Oil and gas	2,558	1,955	5,451	6,034
Oil and gas depreciation, depletion and amortization	4,030	3,120	7,671	5,905
Impairment of oil and gas properties	523	--	523	--
Water treatment plant	436	498	945	927
Mineral holding costs	206	37	316	80
General and administrative	1,760	2,138	3,654	4,549
	9,513	7,748	18,560	17,495
Loss from operations	(991)	(723)	(1,703)	(3,791)
Other income and expenses:				
Realized loss on risk management activities	(6)	(1,015)	(149)	(1,570)
Unrealized gain on risk management activities	1,770	2,138	1,711	897
Gain on the sale of assets	--	137	10	137
Equity loss in unconsolidated investment	(91)	(65)	(151)	(129)
Gain on sale of marketable securities	7	9	54	9
Miscellaneous income and (expenses)	(30)	(37)	88	(38)
Interest income	1	10	6	30
Interest expense	(36)	(34)	(75)	(57)
	1,615	1,143	1,494	(721)
Income (loss) before income taxes and discontinued operations	624	420	(209)	(4,512)

The accompanying notes are an integral part of these statements.

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

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	2012	2011
Income taxes:				
Current (provision for)	--	--	(104)	--
Deferred (provision for) benefit from	(379)	(618)	113	1,976
	(379)	(618)	9	1,976
Income (loss) from continuing operations	245	(198)	(200)	(2,536)
Discontinued operations:				
Discontinued operations, net of taxes	26	123	90	252
Impairment on discontinued operations, net of taxes	(1,261)	--	(1,261)	--
	(1,235)	123	(1,171)	252
Net loss	$(990)	$(75)	$(1,371)	$(2,284)
Net loss per share basic and diluted				
Income (loss) from continuing operations	$0.01	$(0.01)	$(0.01)	$(0.09)
Income (loss) from discontinued operations	(0.05)	0.01	(0.04)	0.01
Net loss	$(0.04)	$--	$(0.05)	$(0.08)
Weighted average shares outstanding				
Basic and Diluted	27,460,483	27,186,438	27,449,534	27,203,336

The accompanying notes are an integral part of these statements.

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

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	2012	2011
Net loss	$(990)	$(75)	$(1,371)	$(2,284)
Other comprehensive income (loss):				
Marketable securities, net of tax	45	(266)	63	(275)
Total comprehensive loss	$(945)	$(341)	$(1,308)	$(2,559)

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 six months ended June 30,	
	2012	2011
Cash flows from operating activities:		
Net loss	$(1,371)	$(2,284)
Loss (income) from discontinued operations	1,171	(252)
Loss from continuing operations	(200)	(2,536)
Adjustments to reconcile net loss to net cash provided by operations		
Depreciation, depletion & amortization	7,980	6,206
Change in fair value of commodity price risk management activities, net	(1,711)	(897)
Accretion of discount on treasury investment	--	(21)
Impairment of oil and gas properties	523	--
Gain on sale of marketable securities	(54)	(9)
Equity loss from Standard Steam	151	129
Net change in deferred income taxes	(80)	(1,725)
(Gain) on sale of assets	(10)	(137)
Noncash compensation	97	758
Noncash services	32	(16)
Net changes in assets and liabilities	287	292
Net cash provided by operating activities	7,015	2,044
Cash flows from investing activities:		
Net redemption of treasury investments	--	16,758
Acquisition & development of oil & gas properties	(30,530)	(29,780)
Acquisition & development of mining properties	--	(48)
Acquisition of property and equipment	(102)	(44)
Proceeds from sale of oil and gas properties	21,475	--
Proceeds from sale of marketable securities	72	11
Proceeds from sale of property and equipment	22	147
Net change in restricted investments	(53)	(206)
Net cash (used in) investing activities:	(9,116)	(13,162)

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 six months ended June 30,	
	2012	2011
Cash flows from financing activities:		
Issuance of common stock	55	(186)
Proceeds from new debt	5,000	13,069
Repayments of debt	(12,135)	(61)
Net cash (used in) provided by financing activities	(7,080)	12,822
Net cash provided by operating activities of discontinued operations	189	241
Net cash used in investing activities of discontinued operations	--	(6)
Net (decrease) increase in cash and cash equivalents	(8,992)	1,939
Cash and cash equivalents at beginning of period	12,874	5,812
Cash and cash equivalents at end of period	$3,882	$7,751
Supplemental disclosures:		
Income tax paid	$--	$--
Interest paid	$63	$90
Non-cash investing and financing activities:		
Unrealized gain	$141	$367
Acquisition and development of oil and gas properties through accounts payable	$6,296	$5,687
Acquisition and development of oil and gas through asset retirement obligations	$92	$134
Amounts receivable from the release of funds held in escrow	$--	$354

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 June 30, 2012 and June 30, 2011 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 June 30, 2012 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, 2011 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 by 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. The unaudited condensed consolidated financial statements should be read in conjunction with the Company's December 31, 2011 Annual Report on Form 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 sets generally accepted accounting principles (U.S. GAAP) that 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 Form 10-K for the year ended December 31, 2011 (Note B pages 86 to 94).

Use of Estimates

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

Properties and Equipment

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

U.S. ENERGY CORP.

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

Components of Property and Equipment as of June 30, 2012 and December 31, 2011 are as follows:

	(In thousands)	
	June 30, 2012	December 31, 2011
Oil & Gas properties		
Unproved	$ 11,769	$ 17,098
Wells in progress	980	2,909
Proved	109,081	99,496
	121,830	119,503
Less accumulated depreciation		
depletion and amortization	(36,231)	(28,561)
Net book value	85,599	90,942
Mining properties	20,739	20,739
Building, land and equipment	15,069	14,984
Less accumulated depreciation	(6,092)	(5,788)
Net book value	8,977	9,196
Totals	$ 115,315	$ 120,877

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 June 30, 2012 and December 31, 2011 which were not included in the amortized cost pool were $12.7 million and $20.0 million, respectively. These costs consist of exploratory wells in progress, seismic costs that are being analyzed for potential drilling locations as well as land costs related to unevaluated properties. No capitalized costs related to unevaluated properties are included in the amortization base at June 30, 2012 and December 31, 2011. It is anticipated that these costs will be added to the full cost amortization pool in the next two years as properties are proved, drilled or abandoned.

U.S. ENERGY CORP.

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

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 was only one such cost center in 2012. 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 June 30, 2012, we used $95.67 per barrel for oil and $3.13 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%.

At June 30, 2012, the Company recorded a proved property impairment of $523,000 related to its oil and gas assets, primarily due to a decline in natural gas prices. There were no proved property impairments recorded during the first six months of 2011. 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.

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 withheld from the depletion calculation. The costs for these wells are then 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 June 30, 2012 and December 31, 2011 reflect capitalized costs associated with our Mt. Emmons molybdenum property near Crested Butte, Colorado.

U.S. ENERGY CORP.

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

Our carrying balance in the Mt. Emmons property at June 30, 2012 and December 31, 2011 is as follows:

	(In thousands)	
	June 30, 2012	December 31, 2011
Costs associated with Mount Emmons beginning of year	$ 20,739	$ 21,077
Development costs	--	16
Option payment from Thompson Creek	--	(354)
Costs at the end of the period	$ 20,739	$ 20,739

Derivative Instruments

The Company uses derivative instruments, typically fixed-rate swaps and costless collars, to manage price risk underlying 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 a cash flow hedge, 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 they are classified as gain (loss) on derivative instruments, net in our consolidated statements of operations. The Company may also use puts, calls and basis swaps in the future.

The Company's Board of Directors sets all risk management policies and reviews the status and results of derivative activities, including volumes, types of instruments and counterparties on a quarterly basis. These policies require that derivative instruments be executed only by the Chief Executive Officer or President. The master contracts with approved counterparties identify the Chief Executive Officer and President as the only Company representatives authorized to execute trades. See Note 6, 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 June 30, 2012 were not significant.

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

U.S. ENERGY CORP.

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

Recent Accounting Pronouncements

On January 1, 2012, the Company adopted Accounting Standards Update No. 2011-05 ("ASC No. 2011-05"), an update to ASC Topic 220 issued by the FASB that states that an entity that reports items of other comprehensive income has the option to present the components of comprehensive income in either one continuous financial statement, or two consecutive financial statements, including reclassification adjustments. Subsequent to the issuance of the authoritative guidance, the FASB issued additional authoritative accounting guidance ("ASC No. 2011-12") that effectively deferred the requirement to present the reclassification adjustments on the face of the financial statements, as well as the requirement to present the individual components of other comprehensive income for interim periods. The Company has elected to present a separate statement of comprehensive income, including the individual components, titled Condensed Consolidated Statements of Comprehensive Loss, as part of Item 1 to this report.

In December 2011, the FASB issued Accounting Standards Update No. 2011-11, Balance Sheet: Disclosures about Offsetting Assets and Liabilities ("ASU 2011-11"). The objective of ASU 2011-11 is to require an entity to provide enhanced disclosures that will enable users of its financial statements to evaluate the effect or potential effect of netting arrangements on an entity's financial position. ASU 2011-11 is effective for interim and annual reporting periods beginning on or after January 1, 2013 and should be applied retrospectively. The adoption of this standard is not expected to have an impact on the Company's consolidated financial statements.

In May 2011, the FASB issued Accounting Standards Update No. 2011-04, Fair Value Measurement: Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs ("ASU 2011-04"), which provides amendments to FASB ASC Topic 820, Fair Value Measurement. The objective of ASU 2011-04 is to create common fair value measurement and disclosure requirements between GAAP and International Financial Reporting Standards ("IFRS"). The amendments clarify existing fair value measurement and disclosure requirements and make changes to particular principles or requirements for measuring or disclosing information about fair value measurements. These amendments are not expected to have a significant impact on companies applying GAAP. ASU 2011-04 is effective for interim and annual periods beginning after December 15, 2011. The adoption of this standard did not have an impact on the Company's consolidated financial statements other than additional disclosures.

3) Mineral Property Transactions

Bakken/Three Forks Shale Sale. On January 24, 2012 (but effective December 1, 2011), we sold an undivided 75% of our undeveloped acreage with Zavanna, LLC ("Zavanna") in the Yellowstone and SEHR prospects to GeoResources, Inc. (56.25%) and Yuma Exploration and Production Company, Inc. (18.75%) for $16.7 million and $1.4 million in reimbursed well costs. These amounts were recorded as credits to our full cost pool. In addition we transferred $5.3 million in costs from unevaluated properties to proved properties as a result of this sale. Under the terms of the agreement, we retained the remaining 25% of our interest in the undeveloped acreage and our original working interest in the initial 10 developed wells in the prospects. Our average working interest in the remaining locations will be approximately 8.75% and net revenue interests in new wells after the sale are expected to be in the range of 6.7375% to 7.0%, proportionately reduced depending on Zavanna's actual working interest percentages.

U.S. ENERGY CORP.

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

Woodbine Acquisition. In May 2012, we entered into a participation agreement with a private entity, Mueller Exploration, Inc. ("Mueller") to participate in the Woodbine Sub-Clarksville 7 Project located in Anderson and Cherokee Counties, Texas. Under the terms of the agreement, we acquired a 26.5% initial working interest (19.6% net revenue interest) in approximately 6,766 gross acres (1,274 net acres to USE) for $1.7 million. The promoted amount covers our portion of the costs for land, geological and geophysical work, as well as all dry hole costs for an initial test well in each of the seven prospects. Upon payout of our initial well costs in each unit, our interest will be reduced to a 19.8% working interest (14.7% net revenue interest). Future infill drilling will be on a heads up basis, and our interest will be a 19.8% working interest (14.7% net revenue interest).

Montana Acreage Sale. On June 8, 2012, we sold an undivided 87.5% of our acreage in Daniels County, Montana to a third party for $3.7 million. This amount was recorded as a credit to our full cost pool. In addition we transferred $1.0 million in costs from unevaluated properties to proved properties as a result of this sale. Under the terms of the agreement, we retained a 12.5% working interest in the acreage and reserved overriding royalty interests (“ORRI”) in leases we owned that had in excess of 81% NRI. The purchaser also committed to drill a vertical test well to depths sufficient to core the Bakken and Three Forks formations on or before December 31, 2015. We delivered an 80% NRI to the purchaser and a 1% ORRI to a land broker. We also paid the land broker a 10% commission for the cash consideration paid by the purchaser.

4) Assets Held for Sale

In January 2011, we made the decision to sell our Remington Village multifamily project in Gillette, Wyoming and plan to use the proceeds to further the development of our oil and gas business. On July 9, 2012, the Company entered into a Letter of Intent (“LOI”) to sell Remington Village for $16.0 million. As a result of the anticipated sale amount, at June 30, 2012, the Company recorded a non-cash impairment of $2.0 million to adjust the carrying value of the project to the expected sale value. Ultimately, we could not reach mutually agreeable terms for the sale and the LOI was terminated. We will continue to market the property for sale.

As of June 30, 2012, the accompanying condensed consolidated balance sheets present approximately $16 million in book value of assets held for sale, net of accumulated depreciation, and $10.2 million in liabilities held for sale. Because Remington Village has been classified as an asset held for sale, scheduled depreciation of $448,000 for the first six months of 2012 and $473,000 for the first six months of 2011 was not recorded. Remington is pledged as collateral on a $10.0 million note. At such time as Remington is sold, the debt balance will be retired.

Operations related to Remington Village are shown in discontinued operations on the accompanying condensed consolidated statements of operations.

5) 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 as well as 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.

U.S. ENERGY CORP.

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

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

	(In thousands)	
	June 30, 2012	December 31, 2011
Beginning asset retirement obligation	$ 510	$ 303
Accretion of discount	16	23
Liabilities incurred	93	187
Liabilities sold	--	(3)
Ending asset retirement obligation	$ 619	$ 510
Mining properties	$ 155	$ 149
Oil & Gas wells	464	361
Ending asset retirement obligation	$ 619	$ 510

6) Commodity Price Risk Management

Through our wholly-owned subsidiary Energy One, we have entered into commodity derivative contracts ("economic hedges") with BNP Paribas ("BNP"), 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 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. The Company does not engage in speculative derivative activities or derivative trading activities, nor does it use derivatives with leveraged features.

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Notes to Condensed Consolidated Financial Statements (Unaudited)
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Energy One's commodity derivative contracts as of June 30, 2012 are summarized below:

Settlement Period	Counterparty	Basis	Quantity (Bbl/d)	Strike Price	
Crude Oil Costless Collar 10/01/11 - 09/30/12	BNP Parabis	WTI	400	Put:	$ 80.00
				Call:	$ 99.00
Crude Oil Costless Collar 01/01/12 - 12/31/12	BNP Parabis	WTI	200	Put:	$ 90.00
				Call:	$ 106.50
Crude Oil Costless Collar 10/01/12 - 09/30/13	BNP Parabis	WTI	200	Put:	$ 95.00
				Call:	$ 116.60

The following table details the fair value of the derivatives recorded in the applicable condensed consolidated balance sheet, by category:

	As of June 30, 2012 (in thousands)			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
Crude oil costless collars	Current Asset	$ 1,112	Current Liability	$ -

Unrealized gains and losses resulting from derivatives 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 contract settlement of derivatives are recorded in the commodity price risk management activities line on the condensed consolidated statement of income.

7) 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.

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

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. As of June 30, 2012, we held $221,000 of investments in marketable securities. We determine our estimate of the fair value of derivate instruments using a market approach based on several factors, including quoted prices in active markets, and quotes from third parties. The fair values of our other accrued liabilities that are reflected on the balance sheet are detailed below. Other accrued liabilities decreased to $795,000 at June 30, 2012 as a result of payments of the liability. The other accrued liabilities are the long term portion of the executive retirement program.

The following table summarizes, by major security type, the fair value and any unrealized gain of our available for sale securities. The unrealized gain is recorded on the condensed consolidated balance sheets as other comprehensive income, a component of shareholders' equity.

(In thousands)

Description	June 30, 2012	Fair Value Measurements at June 30, 2012 Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Commodity risk management assets	$ 1,112	$ --	$ 1,112	$ --
Available for sale securities	221	221	--	--
Assets held for sale	16,180	--	--	16,180
Total assets	$ 17,513	$ 221	$ 1,112	$ 16,180

The following table summarizes the change in the fair value of our Level 3 Fair Value measurements for the six months ended June 30, 2012.

	Change in Level 3 Fair Value Measurements	
December 31,	Revision of Value	June 30

Description	2011		2012
Assets held for sale	$ 18,132	$ (1,952)	$ 16,180

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 since interest rates have remained generally unchanged from the issuance of the debt. The fair value and carrying value of our debt was $15.2 million as of June 30, 2012.

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

8) Debt

At June 30, 2012, total debt in the amount of $15.2 million consists of $9.8 million in debt on our multifamily housing project, $5.0 million in debt from our reserve based senior credit facility and $400,000 in debt related to the purchase of land near our Mt. Emmons molybdenum property.

On May 5, 2011 we borrowed $10.0 million from a commercial bank against Remington Village. At June 30, 2012, the balance due on this note is $9.8 million. The note is collateralized by the Company's multi-family property in Gillette, Wyoming. The note is amortized over 20 years with a balloon payment at the end of five years with an interest rate of 5.50% per annum. Proceeds of the note were used to fund general business obligations. When Remington is sold, the proceeds from the sale will first be applied to the retirement of the debt and the remainder applied to general corporate overhead and project development. Therefore, the debt is included in current liabilities held for sale.

On May 1, 2012, we borrowed $5.0 million under our reserve based senior credit facility to fund our oil and gas programs. The debt has a term of six months and is due in November 2012, but can be continued at our election through July 2014 if we remain in compliance with the covenants under the facility. Our intent is to extend this debt and therefore we have classified it as a long-term liability. The current interest rate on this debt is 2.98%. As of June 30, 2012, Energy One was in compliance with all the covenants under the senior credit facility.

The land debt of $400,000 bears an interest rate of 6.0% per annum and is due in two equal annual payments of $200,000 plus accrued interest. The next payment is due on January 2, 2013.

9) Shareholders' Equity

Common Stock

During the six months ended June 30, 2012, the Company issued 51,070 shares of common stock. These shares consist of (a) 30,000 shares issued to officers of the Company pursuant to the 2001 Stock Compensation Plan, (b) 20,000 shares issued as a result of options being exercised by a former director of the Company and (c) a net of 1,070 shares issued as a result of the exercise of options by an employee of the Company.

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

The following table details the changes in common stock during the three months ended June 30, 2012:

U.S. Energy Corp.
Stockholders' Equity
Year to date through June 30, 2012

(Amounts in thousands, except for share amounts)

	Common Stock		Additional Paid-In
	Shares	Amount	Capital
Balance January 1, 2012	27,409,908	$ 274	$ 122,523
2001 stock compensation plan	30,000	1	95
Exercise of employee stock options	1,070	--	--
Exercise of outside director options	20,000	--	55
Expense of employee options vesting	--	--	2
Expense of outside director warrants vesting	--	--	32
Balance June 30, 2012	27,460,978	$ 275	$ 122,707

Employee Stock Option Plans

All options outstanding at June 30, 2012 were granted pursuant to the U.S. Energy Corp. 2001 Incentive Stock Option Plan (the "2001 ISOP"). The 2001 ISOP had a term of 10 years, and expired on December 6, 2011. Options issued prior to that date will survive to their expiration date which does not exceed a ten year period from date of grant and are subject to vesting and forfeiture provisions.

During the three and six months ended June 30, 2012, we recorded $2,000 in compensation expense for employee stock options. As of June 30, 2012, there was no unrecognized compensation expense related to employee stock option awards. As a result of the exercise of 4,167 options held by a former employee, 1,070 shares of common stock were issued during the six months ended June 30, 2012.

Director Option Plans

From time to time we issue stock options to non-employee directors for services. During the six months ended June 30, 2012, we issued 70,000 options to non-employee directors. The options were issued at the closing price of $2.85

on the date of grant; 60,000 options vest over a three year period and expire ten years from the date of grant or one year after the Board member no longer serves on the Board and 10,000 options vested immediately and expire ten years from the date of grant or one year after the Board member no longer serves on the Board. The options were valued under Black-Scholes using a risk free interest rate of 1.13% to 1.41%, expected life of 5 to 6 years and expected volatility of 62.75% to 63.59%.

During the three and six months ended June 30, 2012, we recorded $15,000 and $37,000, respectively, in expense for options issued to non-employee directors. We will recognize an additional $130,000 in expense over the vesting period of the outstanding options. During the six months ended June 30, 2012, we issued 20,000 shares of common stock to a former director of the Company as the result of the exercise of 20,000 outstanding options.

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

The following table represents the activity in employee stock options and non-employee director stock options for the six months ended June 30, 2012:

	June 30, 2012			
	Employee Stock Options		Stock Purchase Warrants	
	Options	Weighted Average Exercise Price	Warrants	Weighted Average Exercise Price
Outstanding balance at December 31, 2011	2,318,399	$ 3.94	210,000	$ 3.10
Granted	--	$ --	70,000	$ 2.85
Forfeited	--	$ --	--	$ --
Expired	(105,000)	$ 4.39	(120,000)	$ 3.05
Exercised	(4,167)	$ 2.52	(20,000)	$ 2.52
Outstanding at June 30, 2012	2,209,232	$ 3.92	140,000	$ 3.10
Exercisable at June 30, 2012	2,209,232	$ 3.92	63,335	$ 3.01
Weighted Average Remaining Contractual Life - Years		4.53		8.50
Aggregate intrinsic value of options / warrants outstanding		$ -		$ -

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

U.S. ENERGY CORP.

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

11) Segment Information

As of June 30, 2012, we had two reportable segments: Oil and Gas and Maintenance of Mineral Properties. A summary of results of operations for the six months ended June 30, 2012, and 2011, and total assets as of June 30, 2012 and December 31, 2011 by segment are as follows:

	(In thousands) For the three months ended June 30,		(In thousands) For the six months ended June 30,	
	2012	2011	2012	2011
Revenues:				
Oil and gas	$ 8,522	$ 7,025	$ 16,857	$ 13,704
Total revenues:	8,522	7,025	16,857	13,704
Operating expenses:				
Oil and gas	7,111	5,075	13,645	11,939
Mineral properties	642	535	1,261	1,007
Total operating expenses:	7,753	5,610	14,906	12,946
Interest expense				
Oil and gas	28	20	58	29
Mineral properties	6	9	12	18
Total interest expense:	34	29	70	47
Operating (loss) income				
Oil and gas	$ 1,383	$ 1,930	$ 3,154	$ 1,736
Mineral properties	(648)	(544)	(1,273)	(1,025)
Operating income (loss) from identified segments	735	1,386	1,881	711
General and administrative expenses	(1,760)	(2,138)	(3,654)	(4,549)
Add back interest expense	34	29	70	47
Other revenues and expenses:	1,615	1,143	1,494	(721)

Loss before income taxes and discontinued operations	$ 624	$ 420	$ (209)	$ (4,512)
Depreciation depletion and amortization expense:				
Oil and gas	$ 4,030	$ 3,120	$ 7,671	$ 5,905
Mineral properties	32	25	64	51
Corporate	120	124	245	250
Total depreciation expense	$ 4,182	$ 3,269	$ 7,980	$ 6,206

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

	(In thousands)	
	June 30, 2012	December 31, 2011
Assets by segment		
Oil and Gas	$ 94,311	$ 109,141
Mineral	20,754	20,755
Corporate	32,218	32,543
Total assets	$ 147,283	$ 162,439

12) Equity Income in Unconsolidated Investment

We recorded an equity loss from our unconsolidated investment in Standard Steam, LLC (“SST”) during the three and six months ended June 30, 2012 of $91,000 and $151,000, respectively.

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

The following is Management's Discussion and Analysis of significant factors that have affected liquidity, capital resources and results of operations during the three and six months ended June 30, 2012 and 2011. The following also updates information as to our financial condition provided in our 2011 Annual Report on Form 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 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 the Rocky Mountain region (specifically the Williston Basin of North Dakota and Montana), Texas and Louisiana, however, we do not intend to limit our focus to these geographic areas. We continue to focus on increasing production, reserves, revenues and cash flow from operations while managing our level of debt.

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

We are also involved in the exploration for and development of minerals (molybdenum) through our ownership of the Mt. Emmons Molybdenum Project in Colorado. Gross capitalized dollar amounts invested in each of these areas at June 30, 2012 and December 31, 2011 were as follows:

	(In thousands)	
	June 30, 2012	December 31, 2011
Unproved oil and gas properties	$ 12,749	$ 17,098
Proved oil and gas properties	109,081	102,405
Undeveloped mining properties	20,739	20,739
	$ 142,569	$ 140,242

Oil and Gas Activities

We have active agreements with several oil and gas exploration and production companies. Our working interest varies by project, but typically ranges from approximately 5% to 62%. These projects may result in numerous wells being drilled over the next three to five years. We are also actively pursuing the potential acquisition of additional exploration, development or production stage oil and gas properties or companies. The following table details our interests in producing wells as of June 30, 2012 and 2011.

	June 30,			
	2012		2011	
	Gross	Net(1)	Gross	Net(1)
Williston Basin:				
Productive wells	32.00	9.82	19.00	7.15
Wells being drilled or awaiting completion	3.00	0.25	4.00	1.00
Gulf Coast/South Texas:				
Productive wells	3.00	0.56	6.00	1.16
Wells being drilled or awaiting completion	1.00	0.20	2.00	0.27
Eagle Ford:				
Productive wells	2.00	0.60	--	--
Wells being drilled or awaiting completion	1.00	0.30	--	--
Austin Chalk:				
Productive wells	11.00	2.98	11.00	2.98
Wells being drilled or awaiting completion	--	--	--	--
Other areas:				
Productive wells	--	--	--	--
Wells being drilled or awaiting completion	--	--	1.00	0.80
Total:				
Productive wells	48.00	13.96	36.00	11.29
Wells being drilled or awaiting completion	5.00	0.75	7.00	2.07

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

Williston Basin, North Dakota

Rough Rider Prospect. We participate in fifteen 1,280 acre drilling units in the Rough Rider prospect with Brigham Oil & Gas, L.P. (“Brigham”), a subsidiary of Statoil. From August 24, 2009 to June 30, 2012, we have drilled and completed 20 gross Bakken Formation wells (7.34 net) and one gross Three Forks formation well (0.18 net) under the Drilling Participation Agreement with Brigham. Two additional gross wells (0.10 net) are expected to be drilled

during the balance of 2012. Brigham operates all of the wells.

During the first six months of 2012, the Company completed three gross wells (0.45 net) in the Rough Rider prospect. Our net investment in the Rough Rider prospect wells was $3.9 million for the six months ended June 30, 2012.

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 June 30, 2012, we have drilled and completed 11 gross Bakken formation wells (2.31 net) in these prospects, including two gross wells (0.12 net) operated by Murex Petroleum and one gross well (0.01 net) operated by Slawson Exploration Company, Inc. Zavanna operates the remaining wells. At June 30, 2012, three additional gross wells (0.25 net) had been drilled and were awaiting completion.

During the first six months of 2012, we completed six gross wells (1.28 net) and drilled three gross wells (0.25 net) in the Yellowstone and SEHR prospects. Our net investment in the Yellowstone and SEHR prospect wells was $13.9 million during the six months ended June 30, 2012.

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

On June 8, 2012, we sold an undivided 87.5% of our acreage in Daniels County, Montana to a third party for $3.7 million. Under the terms of the agreement, we retained a 12.5% working interest in the acreage and reserved overriding royalty interests ("ORRI") in leases we owned that had in excess of 81% NRI. The purchaser also committed to drill a vertical test well to depths sufficient to core the Bakken and Three Forks formations on or before December 31, 2015. The Company delivered an 80% NRI to the purchaser and a 1% ORRI to a land broker. The Company also paid the land broker a 10% commission for the cash consideration paid by the purchaser.

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

We participate with several different operators in the U.S. Gulf Coast (onshore). At June 30, 2012, we had three gross producing wells (0.56 net) in this region. During the six months ended June 30, 2012, we drilled three gross wells (0.63 net) that were deemed to be nonproductive. Our net costs for these wells through June 30, 2012 were $585,000. One gross well (0.20 net) was in progress at June 30, 2012 and was determined to be non-productive.

In May 2012, we acquired a 26.5% initial working interest in approximately 6,766 gross acres in this area through a cash payment of $1.7 million. The promoted amount covers our portion of the costs for land, geological and geophysical work, as well as the dry hole costs for an initial test well in each of seven different prospects. Upon payout, our working interest will be reduced to 19.8%.

Our net investment in Gulf Coast / South Texas wells and properties was $2.0 million during the six months ended June 30, 2012.

Eagle Ford Shale

We participate in up to 114 gross (34 net) drilling locations in the Leona River and Booth-Tortuga Eagle Ford prospects with Crimson Exploration Inc. ("Crimson"). During the six months ended June 30, 2012, we drilled and completed one gross well (0.30 net) and drilled one gross well (0.30 net) that is expected to be completed during the third quarter of 2012. Our net investment in these wells during the first six months of 2012 was $2.9 million.

2012 Production Results

The following table provides a regional summary of our production during the first six months of 2012:

	Williston Basin	Gulf Coast / South Texas	Eagle Ford	Austin Chalk	Total
First Six Months of 2012 Production					
Oil (Bbl)	182,529	1,937	3,954	3,993	192,412
Gas (Mcf)	70,005	99,883	13,896	1,287	185,071
NGLs (BBs)	6,836	376	209	142	7,563
Equivalent (BOE)	201,032	18,960	6,479	4,349	230,820
Avg. Daily Equivalent (BOE/d)	1,105	104	36	24	1,268
Relative percentage	87%	8%	3%	2%	100%

Additional Comparative Data

The following table provides information regarding selected production and financial information for the quarter ended June 30, 2012 and the immediately preceding three quarters.

	For the Three Months Ended			
	June 30, 2012	March 31, 2012	December 31, 2011	September 30, 2011
	(in Thousands, except for production data)			
Production (BOE)	118,783	112,036	118,663	120,198
Oil, gas and NGL production revenue	$ 8,522	$ 8,335	$ 8,846	$ 8,408
Unrealized and realized derivative (loss) gain	$ 1,764	$ (202)	$ (1,738)	$ 1,564
Lease operating expense	$ 1,630	$ 2,010	$ 1,954	$ 1,811
Production taxes	$ 928	$ 883	$ 921	$ 832
DD&A	$ 4,030	$ 3,641	$ 4,230	$ 3,862
General and administrative	$ 1,760	$ 1,897	$ 1,883	$ 1,829
Mineral holding costs	$ 206	$ 110	$ 140	$ 266
Water treatment plant	$ 436	$ 509	$ 454	$ 497
Income (loss) from continuing operations	$ 624	$ (832)	$ 309	$ 130

Results of Operations

Three Months Ended June 30, 2012 compared to Three Months Ended June 30, 2011

During the three months ended June 30, 2012, we recorded a net loss after taxes of $990,000 as compared to a net loss after taxes of $75,000 during the same period of 2011. Significant components of the change in operating revenues and results of operations for the three months ended June 30, 2012 as compared to the three months ended June 30, 2011 are as follows:

Oil and Gas Operations. Oil and gas operations produced operating income of $1.4 million during the quarter ended June 30, 2012 and 2011. The following table summarizes production volumes, average sales prices and operating revenues for the three months ended June 30, 2012 and 2011:

	Three Months Ended June 30,		Increase (Decrease)
	2012	2011	
Production volumes			
Oil (Bbls)	99,830	56,109	43,721
Natural gas (Mcf)	95,299	238,825	(143,526)
Natural gas liquids (Bbls)	3,070	6,500	(3,430)
Equivalent (BOE)	118,783	102,413	16,370
Avg. Daily Equivalent (BOE/d)	1,305	1,125	180
Average sales prices			
Oil (per Bbl)	$ 81.22	$ 99.77	$ (18.55)
Natural gas (per Mcf)	2.92	4.46	(1.54)
Natural gas liquids (per Bbl)	44.29	55.85	11.56
Operating revenues (in thousands)			
Oil	$ 8,108	$ 5,598	$ 2,510
Natural gas	278	1,064	(786)
Natural gas liquids	136	363	(227)
Total operating revenue	8,522	7,025	1,497
Lease operating expense	(1,630)	(1,289)	(341)
Production taxes	(928)	(667)	(261)
Impairment	(523)	-	(523)
Income before depreciation, depletion and amortization	5,441	5,069	372
Depreciation, depletion and amortization	(4,030)	(3,120)	(910)
Income	$ 1,411	$ 1,949	$ (538)

During the three months ended June 30, 2012, we produced approximately 118,783 barrels of oil equivalent (BOE), or an average of 1,305 BOE/day. 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 are classified in lease operating expenses.

We recognized $8.5 million in revenues during the three months ended June 30, 2012 as compared to $7.0 million during the same period of the prior year. This $1.5 million increase in revenue is primarily due to higher oil sales volumes in 2012 when compared to 2011. Revenue from gas sales was lower in the three months ended June 30, 2012 when compared to the same period in 2011, primarily due to production declines from wells in the Gulf Coast.

Our average net realized price for the three months ended June 30, 2012 was $71.74 per BOE compared with $68.59 for the same period in 2011. The increase in our equivalent realized price for production corresponds with a higher percentage of our production coming from oil in 2012 when compared with 2011. Due to takeaway constraints, the discount, or differential, for oil prices in the Williston Basin has ranged from $10 to $25 per barrel during the first six months of 2012. Until additional takeaway capacity is available, we expect this differential to continue and that our oil sales revenue will be affected by the lower prices.

Lease operating expense of $1.6 million for the three months ended June 30, 2012 was comprised of $1.3 million in lease operating expense and $321,000 in workover expense. The $341,000 increase in total lease operating expense in 2012 as compared to 2011 is primarily a result of an increase in the number of producing wells.

At June 30, 2012, the Company recorded a proved property impairment of $523,000 related to its oil and gas assets, primarily due to a decline in natural gas prices. There were no proved property impairments recorded during the three months ended June 30, 2011.

Our depletion, depreciation and amortization (DD&A) rate for the three months ended June 30, 2012 was $33.92 per BOE compared to $30.46 per BOE for the same period in 2011. We have been impacted by higher DD&A rates related to our Williston Basin wells due to increases in drilling and completion costs for wells in this region. Our DD&A rate can also fluctuate as a result of impairments, divestitures, changes in the mix of our production, the underlying proved reserve volumes and estimated costs to drill and complete proved undeveloped reserves.

During the balance of 2012 we anticipate completing wells that were drilled during the first two quarters of 2012 as well as drilling and completing new wells. We also anticipate that our production rates will increase as a result of these activities. In particular, we expect that oil volumes will increase as we drill and complete oil wells in the Williston Basin and other areas. The anticipated net increase in production is projected to add additional cash flows from operations. However, natural gas and natural gas liquids volumes are expected to continue to decrease as production declines from the Gulf Coast producing wells. However, various factors, including extensive workover costs on existing wells, lower commodity prices, commodity price differentials, cost overruns on projected drilling projects, unsuccessful wells or other development activities and/or faster than expected declines in production from existing wells, would have a negative effect on production, cash flows and earnings from the oil and gas segment and could cause actual results to differ materially from those we expect.

Mt. Emmons and Water Treatment Plant Operations. We recorded $436,000 in costs and expenses for the water treatment plant and $206,000 for holding costs for the Mt. Emmons molybdenum property during the three months ended June 30, 2012. During the three months ended June 30, 2011, we recorded $498,000 in operating costs related to the water treatment plant and $37,000 in holding costs. Holding costs during 2011 were partially funded by another party under an operating agreement. As a result of the termination of this agreement in 2011, our 2012 costs are higher as we now bear all the costs associated with the project.

General and Administrative. General and administrative expenses decreased by $378,000 during the three months ended June 30, 2012 as compared to general and administrative expenses for the three months ended June 30, 2011. Lower general and administrative costs in 2012 are primarily a result of $254,000 lower stock option expense, $142,000 lower bonus accrual and $110,000 lower compensation expense. These decreases in costs were partially offset by an increase in contract services of $137,000.

Other income and expenses. We recognized an unrealized and realized derivative gain of $1.8 million in the second quarter of 2012 compared to a gain of $1.1 million for the same period in 2011. The 2012 amount includes a gain on unrealized changes in the fair value of our commodity derivative contracts of $1.8 million and realized cash settlement losses on derivatives of $6,000.

Gain on the sale of marketable securities from the sale of shares of Sutter Gold Mining decreased to $7,000 during the quarter ended June 30, 2012 from $9,000 during the quarter ended June 30, 2011.

There was no gain on the sale of assets during the quarter ended June 30, 2012 as compared to a gain of $137,000 during the quarter ended June 30, 2011 from the sale of surplus equipment.

We recorded equity losses of $91,000 and $65,000 from the investment in SST during the quarters ended June 30, 2012 and 2011, respectively. Equity losses from the investment in SST are expected to continue until such time as SST properties are sold, equity losses reduce our investment to zero or we sell the investment.

Interest income decreased to $1,000 during the quarter ended June 30, 2012 from $10,000 during the quarter ended June 30, 2011. The decrease is a result of lower amounts of cash invested in interest bearing instruments during the quarter, and lower interest rates received on those investments.

Interest expense increased to $36,000 during the quarter ended June 30, 2012 from $34,000 during the quarter ended June 30, 2011.

Discontinued operations. We recorded income of $26,000, net of taxes from Remington Village during the quarter ended June 30, 2012 and income of $123,000, net of taxes for the quarter ended June 30, 2011. The decrease in income when comparing the quarter ended June 30, 2012 to the quarter ended June 30, 2011 is primarily a result of an increase in the benefit of deferred taxes. The increase was partially offset by higher interest expense and higher contract services costs for the drainage system. On July 9, 2012, the Company entered into a Letter of Intent (“LOI”) to sell Remington Village for $16.0 million. As a result of the anticipated sales amount, at June 30, 2012, the Company recorded a non-cash impairment of $1.3 million net of taxes to adjust the carrying value of the project to the expected sales value. Ultimately, we could not reach mutually agreeable terms for the sale and the LOI was terminated. We will continue to market the property for sale.

We therefore recorded a net loss after taxes of $990,000, or $0.04 per share basic and diluted, during the quarter ended June 30, 2012 as compared to a net loss after taxes of $75,000, or less than $0.01 per share basic and diluted, during the quarter ended June 30, 2011.

Six Months Ended June 30, 2012 compared to Six Months Ended June 30, 2011

During the six months ended June 30, 2012, we recorded a net loss after taxes of $1.4 million as compared to a net loss after taxes of $2.3 million during the same period of 2011. Significant components of the change in operating revenues and results of operations for the six months ended June 30, 2012 as compared to the six months ended June 30, 2011 are as follows:

Oil and Gas Operations. Oil and gas operations produced operating income of $3.2 million during the six months ended June 30, 2012 as compared to operating income of $1.8 million during the six months ended June 30, 2011. The increase in earnings from oil and gas operations is primarily due to (a) a $4.7 million increase in oil revenues during 2012 compared to 2011 and (b) $1.0 million lower lease operating expenses in the six months ending June 30, 2012 as compared to the same period of the prior year. This increase was partially offset by $1.8 million higher depletion expense in 2012 and a $1.6 million decrease in natural gas and natural gas liquids revenues. The following table summarizes production volumes, average sales prices and operating revenues for the six months ended June 30, 2012 and 2011:

	Six Months Ended June 30,		Increase (Decrease)
	2012	2011	
Production volumes			
Oil (Bbls)	192,412	123,459	68,953
Natural gas (Mcf)	185,071	412,580	(227,509)
Natural gas liquids (Bbls)	7,563	11,281	(3,718)
Equivalent (BOE)	230,820	203,503	27,317
Avg. Daily Equivalent (BOE/d)	1,268	1,124	144
Average sales prices			
Oil (per Bbl)	$ 82.77	$ 90.77	$ (8.00)
Natural gas (per Mcf)	2.98	4.61	(1.63)
Natural gas liquids (per Bbl)	50.38	52.92	(2.54)
Operating revenues (in thousands)			
Oil	$ 15,925	$ 11,206	$ 4,719
Natural gas	551	1,901	(1,350)
Natural gas liquids	381	597	(216)
Total operating revenue	16,857	13,704	3,153
Lease operating expense	(3,640)	(4,685)	1,045
Production taxes	(1,811)	(1,349)	(462)
Impairment	(523)	-	(523)
Income before depreciation, depletion and amortization	10,883	7,670	3,213
Depreciation, depletion and amortization	(7,671)	(5,905)	(1,766)
Income	$ 3,212	$ 1,765	$ 1,447

During the six months ended June 30, 2012, we produced approximately 230,820 barrels of oil equivalent (BOE), or an average of 1,268 BOE/day. 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 are classified in lease operating expenses.

We recognized $16.9 million in revenues during the six months ended June 30, 2012 as compared to $13.7 million during the same period of the prior year. This $3.2 million increase in revenue is primarily due to higher oil sales

volumes in 2012 when compared to 2011. Revenue from gas sales is lower in the six months ended June 30, 2012 when compared to the same period in 2011, primarily due to production declines from wells in the Gulf Coast.

Our average net realized price for the six months ended June 30, 2012 was $73.03 per BOE compared with $67.34 for the same period in 2011. The increase in our equivalent realized price for production corresponds with a higher percentage of our production coming from oil in 2012 when compared with 2011. Due to takeaway constraints, the discount, or differential, for oil prices in the Williston Basin has ranged from $10 to $25 per barrel during the first six months of 2012. Until additional takeaway capacity is available, we expect this differential to continue and that our oil sales revenue will be affected by the lower prices.

Lease operating expense of $3.6 million for the six months ended June 30, 2012 was comprised of $2.6 million in lease operating expense and $1.0 million in workover expense. The $1.0 million reduction in total lease operating expense in 2012 as compared to 2011 is primarily a result of $1.8 million lower workover expense, partially offset by higher lease operating expenses as a result of an increase in the number of producing wells.

At June 30, 2012, the Company recorded a proved property impairment of $523,000 related to its oil and gas assets, primarily due to a decline in natural gas prices. There were no proved property impairments recorded during the first six months of 2011.

Our depletion, depreciation and amortization (DD&A) rate for the six months ended June 30, 2012 was $33.23 per BOE compared to $29.02 per BOE for the same period in 2011. We have been impacted by higher DD&A rates related to our Williston Basin wells due to increases in drilling and completion costs for wells in this region. Our DD&A rate can also fluctuate as a result of impairments, divestitures, changes in the mix of our production, the underlying proved reserve volumes and estimated costs to drill and complete proved undeveloped reserves.

During the balance of 2012 we anticipate completing wells that were drilled during the first two quarters of 2012 as well as drilling and completing new wells. We also anticipate that our production rates will increase as a result of these activities. In particular, we expect that oil volumes will increase as we drill and complete oil wells in the Williston Basin and other areas. The anticipated net increase in production is projected to add additional cash flows from operations. However, natural gas and natural gas liquids volumes are expected to continue to decrease as production declines from the Gulf Coast producing wells. However, various factors, including extensive workover costs on existing wells, lower commodity prices, commodity price differentials, cost overruns on projected drilling projects, unsuccessful wells or other development activities and/or faster than expected declines in production from existing wells, would have a negative effect on production, cash flows and earnings from the oil and gas segment and could cause actual results to differ materially from those we expect.

Mt. Emmons and Water Treatment Plant Operations. We recorded $945,000 in costs and expenses for the water treatment plant and $316,000 for holding costs for the Mt. Emmons molybdenum property during the six months ended June 30, 2012. During the six months ended June 30, 2011, we recorded $927,000 in operating costs related to the water treatment plant and $80,000 in holding costs. Holding costs during 2011 were partially funded by another party under an operating agreement. As a result of the termination of this agreement in 2011, our 2012 costs are higher as we now bear all the costs associated with the project.

General and Administrative. General and administrative expenses decreased by $895,000 during the six months ended June 30, 2012 as compared to general and administrative expenses for the six months ended June 30, 2011. Lower general and administrative costs in 2012 are primarily a result of $503,000 lower stock options expense, $202,000 lower bonus accrual, $164,000 lower compensation expense and $158,000 lower stock compensation expense. These decreases in costs were partially offset by an increase in contract services of $194,000 and an increase in insurance costs of $58,000.

Other income and expenses. We recognized an unrealized and realized derivative gain of $1.6 million in the first six months of 2012 compared to a loss of $673,000 for the same period in 2011. The 2012 amount includes a gain on unrealized changes in the fair value of our commodity derivative contracts of $1.7 million and realized cash settlement losses on derivatives of $149,000.

We recorded equity losses of $151,000 and $129,000 from the investment in SST during the six months ended June 30, 2012 and 2011, respectively. Equity losses from the investment in SST are expected to continue until such time as SST properties are sold, equity losses reduce our investment to zero or we sell the investment.

Gain on the sale of marketable securities from the sale of shares of Sutter Gold Mining increased to $54,000 during the six months ended June 30, 2012 from $9,000 during the six months ended June 30, 2011.

Interest income decreased to $6,000 during the six months ended June 30, 2012 from $30,000 during the six months ended June 30, 2011. The decrease is a result of lower amounts of cash invested in interest bearing instruments during the quarter, and lower interest rates received on those investments.

Interest expense increased to $75,000 during the six months ended June 30, 2012 from $57,000 during the six months ended June 30, 2011. The increase in interest expense was related primarily to higher average debt balances during 2012 when compared to 2011.

Discontinued operations. We recorded income of $90,000, net of taxes from the discontinued operations of Remington Village during the six months ended June 30, 2012 and income of $252,000, net of taxes for the six months ended June 30, 2011. The decrease in income is primarily a result of higher deferred benefit for taxes. The increase in income was partially offset by increases in interest expense and higher contract services costs for the drainage system when comparing the six months ended June 30, 2012 to the six months ended June 30, 2011. On July 9, 2012, the Company entered into a Letter of Intent to sell Remington Village for $16.0 million. As a result of the anticipated sales amount, at June 30, 2012, the Company recorded a non-cash impairment of $1.3 million net of taxes to adjust the carrying value of the project to the expected sales value. Ultimately, we could not reach mutually agreeable terms for the sale and the LOI was terminated. We will continue to market the property for sale.

We therefore recorded a net loss after taxes of $1.4 million, or $0.05 per share basic and diluted, during the six months ended June 30, 2012 as compared to a net loss after taxes of $2.3 million, or $0.08 per share basic and diluted, during the six months ended June 30, 2011.

Overview of Liquidity and Capital Resources

At June 30, 2012, we had $3.9 million in cash and cash equivalents. Our working capital (current assets minus current liabilities) was $13.1 million. As discussed below in Capital Resources and Capital Requirements, we project that our capital resources at June 30, 2012 will be sufficient to fund operations and capital projects through the balance of 2012. Given the size of our potential commitments related to our existing inventory of drilling projects, however, our requirements for additional capital could increase significantly during the remainder of 2012 if we elect to participate in any currently unanticipated drilling of additional wells. As a result, we may consider drawing down additional debt on our senior credit facility, selling or joint venturing an interest in some of our oil and gas assets, or accessing the capital markets or other alternatives, as we determine how to best fund our capital program.

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

Capital Resources

Potential primary sources of future liquidity include the following:

Oil and Gas Production. At June 30, 2012, we had forty-eight gross producing wells (13.96 net). During the six months ended June 30, 2012, we received an average of $2.8 million per month from these producing wells with an average operating cost of $425,000 per month (excluding workover costs) and production taxes of $302,000, for average cash flows of $2.1 million per month from oil and gas production before non-cash depletion expense. We anticipate that cash flows from oil and gas operations will increase through the balance of 2012 as additional wells being drilled with Zavanna, Brigham, Crimson and others begin to produce. However, decreases in the price of oil and natural gas, increased operating costs and workover expenses, declines in production rates, and other factors could decrease these average monthly cash flow amounts.

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

Cash on Hand. At June 30, 2012, we had $3.9 million in cash and cash equivalents.

Wells Fargo Senior Credit Facility. On July 30, 2010, we established a senior credit facility through our wholly owned subsidiary, Energy One, LLC (“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 recently acquired the North American reserve-based and related diversified energy lending business of BNP Paribas. The senior credit facility is being used to advance our short and mid-terms goals of increasing our investment in oil and gas.

From time to time until the expiration of the credit facility (July 30, 2014) 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. On April 10, 2012, the commitment amount increased to $100 million and the borrowing base increased to $30.0 million (from $28.0 million) as a result of a redetermination using our December 31, 2011 financial statements, production reports and reserve reports. As of June 30, 2012, Energy One was in compliance with all the covenants under the senior credit facility.

In the first six months of 2012, we borrowed $5.0 million under the senior credit facility to fund our drilling programs.

Equity Market. We filed a registration statement with the Securities and Exchange Commission on October 20, 2009 which became effective on November 6, 2009. The registration statement provides for the sale of up to $100 million of the Company's common stock from time to time. During the fourth quarter of 2009, we sold five million shares of our common stock for $5.25 per share or $26.3 million, $24.3 million net of offering costs. Additional capital may be raised under the registration statement to fund future oil and gas acquisitions and development drilling and other general purposes. Unless extended, the registration statement will expire on November 6, 2012.

Asset Held for Sale – Remington Village. Until Remington Village is sold, we will continue to receive rental receipts from the property. The property had an average occupancy rate of 87% during 2011 and was 92% occupied as of June 30, 2012. Occupancy is dependent on the regional economy, including local coal mining operations, which has been affected by the global recession. The property generated average positive cash flow from operations of $86,000 per month during the first six months of 2012 and cash flow is projected to remain in that range during the balance of 2012.

On May 5, 2011, we borrowed $10.0 million from a commercial bank against Remington Village. The note is amortized over 20 years with a balloon payment at the end of five years and has an interest rate of 5.50% per annum. The proceeds of the note were used to fund our general business obligations.

Capital Requirements

Our direct capital requirements during the balance of 2012 relate to the funding of our drilling programs, additional oil and gas exploration and development projects, acquisition of prospective oil and gas properties and/or existing production, payment of debt obligations, operating and capital improvement costs of the water treatment plant at the Mt. Emmons project and ongoing permitting activities for the Mt. Emmons project, operations at Remington Village until it is sold and general and administrative costs. We intend to finance our 2012 capital expenditure plan primarily from the sources described above under "Capital Resources". We may be required to reduce or defer part of our 2012 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. We continue to expect capital expenditures of approximately $43.3 million in our 2012 oil and gas drilling program (through June 30, 2012, we had spent approximately $23.4 million of this budgeted amount). The remaining $19.9 million in capital expenditure is budgeted to be spent on exploration and acquisition initiatives in the Williston Basin of North Dakota and Texas. Amounts budgeted for each regional drilling program is contingent upon timing, well costs and success. If any of our drilling initiatives are not initially successful or progress more slowly than anticipated, funds allocated for that program may be allocated to other initiatives and/or acquisitions in due course. The actual number of gross and net wells could vary in each of these cases.

Mt. Emmons Molybdenum Project. We are responsible for all costs associated with the Mt. Emmons project, which includes operation of a water treatment plant. Operating costs for the water treatment plant during the remainder of 2012 are expected to be approximately $153,000 per month. Additionally, we have a remaining budget of $550,000 for mining claim fees, permitting and water treatment plant capital improvements that are expected to improve the plant's efficiency and reduce costs.

In 2009, 160 acres of fee land in the vicinity of the mining claims was purchased by the Company and Thompson Creek Metals Company USA ("TCM") for $4 million ($2 million in January 2009, $400,000 annually for five years thereafter). On December 6, 2011, TCM notified the Company that it wishes to sell its interest in the property. The Company has 18 months from that date to decide whether to purchase TCM's interest in the property, at TCM's cost, and close such purchase.

Real Estate. Cash operating expenses at Remington Village are projected to be approximately $89,000 per month until Remington Village is sold. Additionally, we have a remaining budget of approximately $215,000 for capital improvements on the property.

Insurance. We have liability insurance coverage in amounts we deem sufficient and in line with industry standards for the location, stage, and type of operations in oil and gas, mineral property development (the Mt. Emmons molybdenum project), and the Remington Village housing complex. 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 $464,000 related to our oil and gas wells and $156,000 related to the Mt. Emmons molybdenum property. One depleted oil and gas well in Louisiana is expected to be plugged and abandoned in 2012 at a projected net cost to the Company of $46,000. No additional reclamation is expected to be performed during the year ended December 31, 2012 unless a well, or wells, are abandoned due to unexpected operational challenges. As the Mt. Emmons project is developed, the reclamation liability is expected to increase. It is not anticipated that his reclamation work will occur in the near term. 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 six months ended June 30, 2012

The following table presents changes in cash flows between the six month periods ended June 30, 2012 and 2011. 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 six months ended June 30,		
	2012	2011	Change
Net cash provided by operating activities	$ 7,015	$ 2,044	$ 4,971
Net cash (used in) investing activities	(9,116)	(13,162)	4,046
Net cash (used in) provided by financing activities	(7,080)	12,822	(19,902)

Operating Activities. Cash provided by operations for the six month period ended June 30, 2012 increased to $7.0 million as compared to cash provided by operations of $2.0 million for the same period of the prior year. This $5.0 million year over year increase in cash from operating activities is predominantly a result of a $3.2 million improvement in oil, gas and NGL production revenues and $1.0 million lower lease operating expenses. The remainder of the change in cash provided by operations is part of the complete discussion of cash provided by operations in the Results of Operations above.

Investing Activities. Investing activities provided cash during the first six months of 2012 through $21.5 million in proceeds from the sale of oil and gas properties, $72,000 from the sale of shares of Sutter Gold Mining and $22,000 from the sale of property and equipment.

Investing activities consumed cash through the acquisition and development of oil and gas properties in the amount of $30.5 million during the first six months of 2012. Other uses of cash for investing activities in the period were a $55,000 change in restricted investments and $102,000 for the purchase of equipment.

The $4.0 million increase from investing activities during the six months ended June 30, 2012 as compared to the same period of the prior is primarily a result of: (a) $21.5 million in sales of oil and gas properties during 2012 with no oil and gas property sales during the same period in 2011 and (b) $16.8 million in redemption of treasury investments in 2011 and no redemption of treasury investments in 2012.

Financing Activities. Financing activities consumed $7.1 million during the six months ended June 30, 2012. Components of the cash outflow include $12.1 million in repayments of debt, net of borrowings of $5.0 million under our credit facility and $55,000 of proceeds through the issuance of common stock. During the six months ended June 30, 2011 financing activities provided $12.8 million. Components of cash flow from financing activities during the six months ended June 30, 2011 include the provision of $13.1 million from new debt and outflows of $186,000 from the exercise of employee options and non-employee warrants and $61,000 in debt payments.

Critical Accounting Policies

For detailed descriptions of our significant accounting policies, we refer you to the corresponding section of Part II, Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2011 (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 enhance acquisitions of properties related to that commodity, but could also make sales of such properties more difficult. Operational impacts of changes in commodity prices are common in the oil and gas and mining industries.

At June 30, 2012, 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 of 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 (the "Securities Act"), 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 statemen 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, expenses and capital projects. 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 Company's Risk Factors included in our Annual Report on Form 10-K and 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.

Off-Balance Sheet Arrangements

None.

Contractual Obligations

We had three principal categories of contractual obligations at June 30, 2012: Debt to third parties of $15.2 million, executive retirement obligations of $920,000 and asset retirement obligations of $620,000. The debt consists of debt to a commercial bank secured by our multi-family property in Gillette, WY, debt related to our oil and gas reserves and the purchase of land near our Mt. Emmons molybdenum property. The debt to the commercial bank bears an interest rate of 5.5% per annum and the land debt bears an interest rate of 6.0% per annum. The debt to the commercial bank is amortized over 20 years with a balloon payment due at the end of five years on May 5, 2016. The balloon payment at maturity is $8.8 million. The oil and gas debt is for a term of six months and is due in November 2012. The payment due in November 2012 will be $5.0 million plus accrued interest. This debt can be continued at our election through July 2014 if we remain in compliance with the covenants under the senior credit facility. The $400,000 land debt is due in two equal annual payments of $200,000, plus accrued interest. The next payment is due on January 2, 2013. The executive retirement liability will be paid out over varying periods starting after the actual projected retirement dates of the covered executives. The asset retirement obligations will be retired during the next 34 years. The following table shows the scheduled debt payment, projected executive retirement benefits and asset retirement obligations as of June 30, 2012. This table reflects the debt obligation on the Remington Village apartment complex under the terms of the note. However, because the related property is reflected as a current asset held for sale, the note is also classified in the financial statements as a current liability held for sale.

	(In thousands) Payments due by period				
	Total	Less than one Year	One to Three Years	Three to Five Years	More than Five Years
Debt obligations	$ 15,169	$ 508	$ 14,661	$ --	$ --
Executive retirement	920	125	327	163	305
Asset retirement obligation	619	46	23	14	536
Totals	$ 16,708	$ 679	$ 15,011	$ 177	$ 841

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, which will impact our prospective revenues.

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

Through Energy One, we have entered into commodity derivative contracts ("economic hedges") with BNP Paribas, consisting of three costless collars as described below. The derivative contracts are priced using West Texas Intermediate ("WTI") quoted prices. U.S. Energy is a guarantor of Energy One's obligations under the economic hedges.

Energy One's commodity derivative contracts as of June 30, 2012 are summarized below:

Settlement Period	Counterparty	Basis	Quantity (Bbl/d)	Strike Price	
Crude Oil Costless Collar 10/01/11 - 09/30/12	BNP Parabis	WTI	400	Put:	$ 80.00
				Call:	$ 99.00
Crude Oil Costless Collar 01/01/12 - 12/31/12	BNP Parabis	WTI	200	Put:	$ 90.00
				Call:	$ 106.50
Crude Oil Costless Collar 10/01/12 - 09/30/13	BNP Parabis	WTI	200	Put:	$ 95.00
				Call:	$ 116.60

The following table details the fair value of the derivatives recorded in the applicable condensed consolidated balance sheet, by category:

	As of June 30, 2012 (in thousands)			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
Crude oil costless collars	Current Asset	$ 1,112	Current Liability	$ -

These contracts are accounted for using the mark-to-market accounting method and accordingly, we recognize all unrealized and realized gains and losses related to these contracts currently in earnings and such gains and losses are classified as gain (loss) on derivative instruments, net in our consolidated statements of operations.

ITEM 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of June 30, 2012, the Company's management, including its Chief Executive Officer and Principal Accounting 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 Securities and Exchange Act of 1934, as amended (the "Exchange Act")). Based on that evaluation the Chief Executive Officer and Principal Accounting 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 Principal Accounting 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 June 30, 2012 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

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

On June 30, 2012, the District Court affirmed the Colorado Land Board's decision that: (i) the activities proposed by the NOI and MD-03 are prospecting, not development or mining and (ii) the current financial warranty amount posted by the Company is sufficient to cover the proposed activities. The District Court dismissed the HCCA's complaint and authorized the reimbursement of the Company's costs from HCCA upon the filing the proper paperwork. On July 25, 2012, HCCA filed an appeal of the District Court's decision with the Colorado Court of Appeals.

There have been no other material changes from the legal proceedings as previously disclosed in our 2011 Form 10-K in response to Item 3 of Part I of such Form 10-K (pages 45-47).

ITEM 1A. Risk Factors

There have been no material changes to the risk factors discussed in Part I, "Item 1A - Risk Factors" (pages 16 to 30) in the Company's Annual Report on Form 10-K for the year ended December 31, 2011, which are expected to materially affect the Company's business, financial condition or future results. Additional risks and uncertainties not currently known to the Company or that it currently deems to be immaterial also may materially adversely affect its business, financial condition and/or operating results.

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

During the six months ended June 30, 2012, the Company issued 30,000 shares pursuant to the 2001 Stock Award Plan, comprised of 10,000 shares to each of the executive officers of the Company.

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 Rule 13a-15(e) / Rule 15d-15(e)
31.2	Certification of Principal Accounting Officer Pursuant to Rule 13a-14(a) / Rule 15(e)/15d-15(e)

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 Principal Accounting Officer Pursuant to 18 U.S.C. Section 1350, as adopted by Section 906 of the Sarbanes-Oxley Act of 2002

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: August 9, 2012	By:	/s/ Keith G. Larsen KEITH G. LARSEN Chairman and CEO
Date: August 9, 2012	By:	/s/ Bryon G. Mowry BRYON G. MOWRY Principal Accounting Officer