UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K /A

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2011 or

☐ **TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from __________to_________

Commission file number: 333-152571

Recovery Energy, Inc.
(Name of registrant as specified in its charter)

NEVADA	**74-3231613**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1515 Wynkoop Street, Suite 200, Denver, CO 80202
(Address of principal executive offices, including zip code)

Registrant's telephone number including area code: (303)-951-7920

Securities registered under Section 12(b) of the Act:

None

Securities registered under Section 12(g) of the Act:

Title of each class
$0.0001 par value Common Stock

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Exchange Act. Yes ☐ No ☒

Indicate by check mark if 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 past 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers in response to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company (as defined in Rule 12b-2 of the Act):

Large accelerated filer	☐	Accelerated filer	☒
Non-accelerated filer	☐	Smaller reporting company	☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐No ☒

State the aggregate market value of voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the fiscal quarter ending June 30, 2011: $91,409,723

As of March 9, 2012, 17,532,711 shares of the registrant’s common stock were issued and outstanding.

FORM 10-K ANNUAL REPORT
FISCAL YEAR ENDED DECEMBER 31, 2011
RECOVERY ENERGY, INC

FORWARD-LOOKING STATEMENTS

This annual report contains “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995. All statements other than statements of historical fact are “forward-looking statements” for purposes of federal and state securities laws, including, but not limited to, any projections of earnings, revenue or other financial items; any statements of the plans, strategies and objectives of management for future operations; any statements concerning future production, reserves or other resource development opportunities, any projected well performance or economics, or potential joint ventures or strategic partnerships; any statements regarding future economic conditions or performance; any statements of belief; and any statements of assumptions underlying any of the foregoing.

Forward-looking statements may include the words “may,” “should,” “could,” “estimate,” “intend,” “plan,” “project,” “continue,” “believe,” “expect” or “anticipate” or other similar words. These forward-looking statements present our estimates and assumptions only as of the date of this presentation. Except as required by law, we do not intend, and undertake no obligation, to update any forward-looking statement.

Although we believe that the expectations reflected in any of our forward-looking statements are reasonable, actual results could differ materially from those projected or assumed in any of our forward-looking statements. Our future financial condition and results of operations, as well as any forward-looking statements, are subject to change and inherent risks and uncertainties. The factors impacting these risks and uncertainties include, but are not limited to:

• *estimated quantities and quality of oil and natural gas reserves;*
• *exploration, exploitation and development results;*
• *fluctuations in the price of oil and natural gas, including reductions in prices that would adversely affect our revenue, cash flow, liquidity and access to capital;*
• *availability of capital on an economic basis, or at all, to fund our capital needs;*
• *availability of, or delays related to, drilling, completion and production, personnel, supplies and equipment;*
• *the timing and amount of future production of oil and gas;*
• *the completion, timing and success of our drilling activity;*
• *the inability of management to effectively implement our strategies and business plans;*
• *potential default under our secured obligations or material debt agreements;*
• *lower oil and natural gas prices negatively affecting our ability to borrow or raise capital, or enter into joint venture arrangements;*
• *declines in the values of our natural gas and oil properties resulting in write-downs;*
• *inability to hire or retain sufficient qualified operating field personnel;*
• *increases in interest rates or our cost of borrowing;*
• *deterioration in general or regional (especially Rocky Mountain) economic conditions;*
• *the strength and financial resources of our competitors;*
• *the occurrence of natural disasters, unforeseen weather conditions, or other events or circumstances that could impact our operations or could impact the operations of companies or contractors we depend upon in our operations;*
• *inability to acquire or maintain mineral leases at a favorable economic value that will allow us to expand our development efforts;*
• *delays, denials or other problems relating to our receipt of operational consents and approvals from governmental entities and other parties*
• *unanticipated recovery or production problems, including cratering, explosions, fires and uncontrollable flows of oil, gas or well fluids;*
• *environmental liabilities;*
• *loss of senior management or technical personnel;*
• *adverse state or federal legislation or regulation that increases the costs of compliance, or adverse findings by a regulator with respect to existing operations;*
• *changes in U.S. GAAP or in the legal, regulatory and legislative environments in the markets in which we operate; and*
• *other factors, many of which are beyond our control.*

Many of these factors are beyond our ability to control or predict. These factors are not intended to represent a complete list of the general or specific factors that may affect us.

For a detailed description of these and other factors that could cause actual results to differ materially from those expressed in any forward-looking statement, we urge you to carefully review and consider the disclosures made in the "Risk Factors" sections of our SEC filings, available free of charge at the SEC's website (www.sec.gov).

PART I

Items 1. and 2. BUSINESS and PROPERTIES

Industry terms used in this report are defined in the Glossary of Oil and Natural Gas Terms located at the end of this Item 1 and 2.

General

Recovery Energy Inc. is a Denver based independent oil and gas company engaged in the acquisition, drilling and production of oil and natural gas properties and prospects within the Denver-Julesburg ("DJ") Basin. Our business strategy is designed to create maximum shareholder value by leveraging the knowledge, expertise and experience of our management team and via the future exploration and development of the approximate 130,000 net acres of developed and undeveloped leases that are currently held by the Company, primarily in the northern DJ Basin.

Our executive offices are located at 1515 Wynkoop Street, Suite 200, Denver, Colorado 80202, and our telephone number is (303) 951-7920. Our web site is www.recoveryenergyco.com. Additional information which may be obtained through our web site does not constitute part of this annual report on Form 10-K. Our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports are accessible free of charge at our website. The SEC also maintains an internet site that contains reports, proxy and information statements and other information regarding our filings at www.sec.gov.

Company Overview & Strategy

We have developed and acquired an oil and natural gas base of proved reserves, as well as a portfolio of exploration and development prospects with high-impact conventional and non-conventional reservoir opportunities with an emphasis on multiple producing horizons and the Niobrara shale resource play. We believe these prospects offer the possibility of repeatable success allowing for meaningful production and reserve growth. Our acquisition and exploration pursuits of oil and natural gas properties are principally located in Colorado, Nebraska, and Wyoming. Since early 2010 we have acquired and/or developed 21 producing wells. As of December 31, 2011 we owned interests in approximately 144,000 gross (130,000 net) leasehold acres, of which 134,000 gross (121,000 net) acres are classified as undeveloped acreage and all of which are located in Colorado, Wyoming and Nebraska in the DJ Basin. We intend to continue to evaluate and invest in acquisitions and internally generated prospects. It is our long-term goal to maximize our DJ Basin acreage position through development drilling of our conventional horizons as well as development of our Niobrara shale potential.

We have invested, and intend to continue to invest, primarily in oil and natural gas interests, including producing properties, prospects, leases, wells, mineral rights, working interests, royalty interests, overriding royalty interests, net profits interests, production payments, farm-ins, drill to earn arrangements, partnerships, easements, rights of way, licenses and permits, in the DJ Basin in Colorado, Nebraska, and Wyoming.

As of December 31, 2009, we had not successfully acquired any properties; therefore our total production was 0 Mboe net. Subsequent to December 31, 2009, we successfully completed a number of acquisitions which resulted in 136 Mboe of production for the year ended December 31, 2010. In 2011, we drilled and completed 6 gross, 5 net wells and recorded net production of 101 Mboe during the year.

It is our belief that the exploration and production industry's most significant value creation occurs through the drilling of successful development wells and the enhancement of oil recovery in mature fields given appropriate economic conditions. Our goal is to create significant value while maintaining a low cost structure. To this end, our business strategy includes the following elements:

Participation in development prospects in known producing basin. We pursue prospects in one known producing onshore basin, the DJ Basin, where we can capitalize on our development and production expertise. We intend to operate the majority of our properties and evaluate each prospect based on its geological and geophysical merits.

Negotiated acquisitions of properties. We acquire producing properties based on our view of the pricing cycles of oil and natural gas and available exploration and development opportunities of proved, probable and possible reserves.

Retain Operational Control and Significant Working Interest. In our principal development targets, we typically seek to maintain operational control of our development and drilling activities. As operator, we retain more control over the timing, selection and process of drilling prospects and completion design, which enhances our ability to maximize our return on invested capital and gives us greater control over the timing, allocation and amounts of our capital expenditures. We have continued to maintain high working interest in our DJ Basin properties which maximizes our exposure to generated cash flows and increases in value as the properties are developed. With operational control, we can also schedule our drilling program to satisfy most of our lease stipulations and continue to put our acreage into “held by production” status, thus eliminating expirations. The majority of our acreage is contiguous which will permit efficiencies in drilling and production operations.

Leasing of Prospective Acreage. In the course of our business, we identify drilling opportunities on properties that have not yet been leased. At times, we take the initiative to lease Prospective Acreage and we may sell all or any portion of the leased acreage to other companies that want to participate in the drilling and development of the prospect acreage.

Controlling Costs. We maximize our returns on capital by minimizing our expenditures on general and administrative expenses. We also minimize initial capital expenditures on geological and geophysical overhead, seismic data, hardware and software by partnering with cost efficient operators that have already invested capital in such. Historically, we also outsourced some of our geological, geophysical, reservoir engineering and land functions in order to help reduce capital requirements. We recently brought many of these functions in-house to provide us with greater ability to maximize the value of our growing leasehold position.

We use commodity price hedging instruments to reduce our exposure to oil and natural gas price fluctuations and to help ensure that we have adequate cash flow to fund our debt service costs and capital programs. From time to time, we will enter into futures contracts, collars and basis swap agreements, as well as fixed price physical delivery contracts. We intend to use hedging primarily to manage price risks and returns on certain acquisitions and drilling programs. Our policy is to consider hedging an appropriate portion of our production at commodity prices we deem attractive. In the future we may also be required by our lenders to hedge a portion of production as part of any financing.

We currently own interest in 144,000 gross, 130,000 net developed and undeveloped acres in DJ basin leases, and will require access to substantial capital in order to fully assess and develop our inventory of undeveloped acreage.

Principal Oil and Gas Interests

As of December 31, 2011 we owned 21 producing wells, 7 shut-in wells, 2 injection wells, and 2 wells in progress in the Wyoming, Nebraska and Colorado portions of the DJ Basin, as well as approximately 144,000 gross (130,000 net) acres, of which 134,000 gross (121,000 net) acres are classified as undeveloped acreage. Our primary targets within the DJ Basin are the conventional Dakota and Muddy ‘J’ formations, in addition to the developing unconventional Niobrara shale play. Additional horizons include the Coddell, Greenhorn and Pierre Shale.

During 2011, we made capital expenditures of approximately $16.4 million, including $9.4 million for the purchase of unevaluated leases and $7.4 million related to drilling and completion operations where we drilled 4 gross (3.25 net) wells and completed 3 gross (2.25 net) wells; also, as of December 31, 2011 we had 2 gross (1.75 net) wells in progress.

As of December 31, 2011 we had net proved reserves of 633 Mboe, and for the year ending December 21, 2011 we produced 101 Mboe.

2012 Capital Budget

Our anticipated 2012 capital expenditure budget is $10-15 million, which is allocated primarily to the drilling and completion of oil and gas wells in the DJ Basin in Wyoming, Nebraska and Colorado targeting the conventional Dakota 'D' sand and Muddy 'J' sand targets. In addition, approximately 1/3 of this budget may be directed toward additional development procedures on certain unconventional Niobrara shale properties. We estimate the completed cost for each conventional well to be between $800,000 and $900,000. Specific allocations of the 2012 budget directed at Niobrara shale properties have not been determined at this time.

Our 2012 capital expenditure budget is subject to various factors, including market conditions, availability of capital, oilfield services and equipment availability, commodity prices and drilling results. While we continue to explore opportunities to expand our acreage position, our current budget is allocated to drilling and completing wells. Any leasehold acquisitions that we choose to pursue would require us to adjust our budget. Results from the wells identified in the capital budget may lead to additional adjustments to the capital budget as the cash flow from the wells could provide additional capital which we may use to increase our capital budget.

Other factors that could cause us to further increase our level of activity and adjust our capital expenditure budget include a reduction in service and material costs, the formation of joint ventures with other exploration and production companies, the divestiture of non-strategic assets, a further improvement in commodity prices or well performance that exceeds our forecasts, any of which could positively impact our operating cash flow. Factors that could cause us to reduce level of activity and adjust our capital budget include, but are not limited to, increases in service and materials costs, reductions in commodity prices or under-performance of wells relative to our forecasts, any of which could negatively impact our operating cash flow.

Capital Resources

Our 2012 drilling program is designed to provide flexibility to accommodate both the timing of the securing of adequate capital, and to identify suitable well locations. We anticipate funding the 2012 capital program through a combination of the issuance of additional equity or debt securities, cash flow from future operations and from cash provided by potential joint venture participants. We may also choose to sell certain non-strategic assets in order to supplement the funding of our 2012 capital budget.

We cannot give assurances that our working capital on hand, our cash flow from operations or any available borrowings, equity offerings or other financings, or sales of non-strategic assets will be sufficient to fund our anticipated capital expenditures. If our existing and potential sources of investment capital are not sufficient to undertake our planned 2012 capital expenditures, we may be required to reduce our 2012 drilling capital budget, curtail our expenditures and/or restructure our operations.

Reserves

The table below presents summary information with respect to the estimates of our proved oil and gas reserves for the year ended December 31, 2011. Prior to January 2010, we did not own any reserves nor did we have any production. We engaged Ralph E Davis Associates, Inc. ("RE Davis") to audit internal engineering estimates for 100 percent of the PV-10 value of our proved reserves in 2011. The prices used in the calculation of proved reserve estimates as of December 31, 2011 were $88.16 per Bbl and $3.96 per Mcf and as of December 31, 2010, were $78.93 per Bbl and $4.39 per Mcf for oil and natural gas, respectively. The prices were adjusted for basis differentials, pipeline adjustments, and BTU content.

We emphasize that reserve estimates are inherently imprecise and that estimates of all new discoveries and undeveloped locations are more imprecise than estimates of established producing oil and gas properties. Accordingly, these estimates are expected to change as new information becomes available. The PV-10 values shown in the following table are not intended to represent the current market value of the estimated proved oil and gas reserves owned by us. Neither prices nor costs have been escalated. The following table should be read along with the section entitled "Risk Factors — Risks Related to Our Company - The actual quantities and present values of our proved oil and natural gas reserves may be less than we have estimated." No estimates of our proved reserves have been filed with or included in reports to any federal authority or agency, other than the Securities and Exchange Commission ("SEC"), since the beginning of the last fiscal year. We did not have third party engineers review probable, possible and resource based reserves as of December 31, 2011. These reserve categories are currently being determined across our substantial acreage position and are expected to identify significant potential in all unproven classifications and from multiple horizons.

	As of December 31,		
	2011	**2010 (1)**	**2009 (1)**
Reserve data:			
Proved developed			
Oil (MBbl)	216	278	-
Gas (MMcf)	148	308	-
MBOE	240	329	-
Proved undeveloped			
Oil (MBbl)	392	415	-
Gas (MMcf)		-	-
MBOE	392	415	-
Total Proved			
Oil (MBbl)	608	693	-
Gas (MMcf)	148	308	-
MBOE	633	744	-
Proved developed reserves %	38%	44%	-%%
Proved undeveloped reserves %	62%	56%	-%%
Reserve value data :			
Proved developed PV-10	$ 10,204,160	$ 11,377,009	$ -
Proved undeveloped PV-10	9,809,885	12,217,798	-
Total proved PV-10	$ 20,014,045	$ 23,594,807	$ -
Standardized measure of discounted future cash flows	$ 20,014,045	$ 23,594,807	$ -
Reserve life (years)	22.58	21.92	-

(1) Prior to January 2010, the Company did not own any oil and gas properties

As we currently do not expect to pay income taxes in the future, there is no difference between the PV-10 value and the standard measure of future net cash flows. Please see the definitions of standardized measure of discounted future net cash flows and PV-10 value in the Glossary.

Internal Controls Over Reserves Estimate

Our policy regarding internal controls over the recording of reserves is structured to objectively and accurately estimate our oil and gas reserve quantities and values in compliance with the regulations of the SEC. Responsibility for compliance in reserve bookings is delegated to our Senior Reservoir Engineer.

Technical reviews are performed throughout the year by engineering and geologic staff who evaluate all available geological and engineering data. This data, in conjunction with economic data and ownership information, is used in making a determination of estimated proved reserve quantities. The reserve process is overseen by Kent Lina, Senior Reserve Engineer. Mr. Lina joined us in October 2010. Mr. Lina was employed by Delta Petroleum Company from March 2002 to September 2010 in various operations and reservoir engineering capacities culminating as the Senior V.P. of Corporate Engineering. Mr. Lina received a Bachelor of Science degree in Civil Engineering from University of Missouri at Rolla in 1981.

Third-party Reserves Study

An independent third party reserve study as of December 31, 2011 was performed by RE Davis using their own engineering assumptions and other economic data provided by us. One-hundred percent of our total calculated proved reserve PV-10 value was audited by RE Davis. RE Davis is an independent petroleum engineering consulting firm that has been providing petroleum engineering consulting services for over 20 years. The technical person at RE Davis primarily responsible for overseeing our reserve audit is the President and CEO who received a Bachelor of Science degree in Chemical and Petroleum Engineering from the University of Houston and is a registered Professional Engineer in the States of Texas. He is also a member of the Society of Petroleum Engineers. The RE Davis report dated March 5, 2012 is included as Exhibit 99.1 to this annual report.

Oil and gas reserves and the estimates of the present value of future net revenues therefrom were determined based on prices and costs as prescribed by SEC and FASB guidelines. Reserve calculations involve the estimate of future net recoverable reserves of oil and gas and the timing and amount of future net revenues to be received therefrom. Such estimates are not precise and are based on assumptions regarding a variety of factors, many of which are variable and uncertain. Proved oil and gas reserves are the estimated quantities of oil and gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods. Proved reserves were estimated in accordance with guidelines established by the SEC and the FASB, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations except by contractual arrangements. For the year ended December 31, 2011, commodity prices over the prior 12-month period and year end costs were used in estimating net cash flows.

In addition to a third party reserve study, our reserves are reviewed by senior management and the audit committee of our board of directors. Our chief executive officer is responsible for reviewing and verifying that the estimate of proved reserves is reasonable, complete, and accurate. The audit committee reviews the final reserves estimate in conjunction with RE Davis's audit letter.

Production

The following table summarizes the average volumes and realized prices, including and excluding the effects of our economic hedges, of oil and gas produced from properties in which we held an interest during the periods indicated. Also presented is a production cost per BOE summary:

	For the Year Ended December 31,		
	2011	**2010**	**2009 (1)**
Net production			
Oil (MMBbl)	81,433	133.709	-
Gas (MMcf)	115,583	14.914	-
MBOE	100,707	136.195	-
Average net daily production			
Oil (Bbl)	223	366	-
Gas (Mcf)	317	41	-
BOE	275	373	-
Average realized sales price, excluding the effects of our economic hedges			
Oil (per Bbl)	$ 87.77	$ 71.08	$ -
Gas (per Mcf)	$ 4.73	$ 4.56	$ -
Per BOE	$ 76.41	$ 70.29	$ -
Average realized sales price, including the effects of our economic hedges			
Oil (per Bbl)	$ 95.44	$ 75.27	$ -
Gas (per Mcf)	$ 4.73	$ 4.56	$ -
Per BOE	$ 82.62	$ 74.47	$ -
Production costs per BOE			
Lease operating expense	$ 15.19	$ 6.33	$ -
DD&A	$ 42.25	$ 36.98	$ -
Production taxes	$ 8.18	$ 7.76	$ -

(1) Prior to January 2010, the Company did not own any oil and gas properties

Productive Wells

As of December 31, 2011, we had working interests in 17 gross (16.2 net) productive oil wells, and 4 gross (2.4 net) productive gas wells. Productive wells are either wells producing in commercial quantities or wells capable of commercial production although currently shut-in. Multiple completions in the same wellbore are counted as one well. A well is categorized under state reporting regulations as an oil well or a gas well based on the ratio of gas to oil produced when it first commenced production, and such designation may not be indicative of current production.

Acreage

As of December 31, 2011 we owned 21 producing wells in the Wyoming, Nebraska and Colorado portion of the DJ Basin, as well as approximately 144,000 gross (130,000 net) acres, of which 134,000 gross (121,000 net) acres were classified as undeveloped acreage.

As of December 31, 2011 our primary assets included acreage located in Laramie County and Goshen counties Wyoming, Banner, Kimball, and Scotts Bluff Counties, Nebraska, and Weld, Arapahoe and Elbert Counties, Colorado.

The following table sets forth certain information with respect to our developed and undeveloped acreage as of December 31, 2011.

	Undeveloped		Developed	
	Gross	Net	Gross	Net
DJ Basin	134,191	121,071	9,937	9,118
Total	134,191	121,071	9,937	9,118

Drilling Activity

The following table describes the development and exploratory wells we drilled during the years ended December 31, 2011, 2010, and 2009.

	For the Year Ended December 31,					
	2011		2010		2009 (1)	
	Gross	Net	Gross	Net	Gross	Net
Development:			-	-	-	-
Productive wells	3.0	2.25	2.0	1.4	-	-
Dry wells	1.0	1.0	1.0	0.7	-	-
	4.0	3.25	3.0	2.1	-	-
Exploratory:						
Productive wells	-	-	-	-	-	-
Dry wells	-	-	-	-	-	-
	-	-	-	-	-	-
Total	4.0	3.25	3.0	2.1	-	-

(1) Prior to January 2010, the Company did not own any oil and gas assets

A productive well is an exploratory, development or extension well that is not a dry well. A dry well (hole) is an exploratory, development, or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

As defined in the rules and regulations of the SEC, an exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. A development well is part of a development project, which is defined as the means by which petroleum resources are brought to the status of economically producible. The number of wells drilled refers to the number of wells completed at any time during the respective year, regardless of when drilling was initiated. Completion refers to the installation of permanent equipment for production of oil or gas, or, in the case of a dry well, to the reporting to the appropriate authority that the well has been abandoned.

As of December 31, 2011 we had 2 gross (1.75 net) wells in progress.

Major Customers

During 2011 and 2010, the Company had one customer, Shell Trading (US), individually accounting for approximately 76 percent and 64 percent, respectively, of our revenues. During 2009, the Company did not have any production or customers.

Employees

As of March 15, 2012 we had 10 employees, including two part time employees. For the foreseeable future, we intend to only add additional personnel as our operational requirements grow. In the interim, we plan to continue to use the services of independent consultants and contractors to perform various professional services, including land, legal, environmental and tax services. We believe that by limiting our management and employee costs, we are able to better control total costs and retain flexibility in terms of project management.

Title to Properties

Substantially all of our interests are held pursuant to leases from third parties. The majority of our producing properties are subject to mortgages securing indebtedness under our credit facility that we believe do not materially interfere with the use of or affect the value of such properties. We typically perform only minimal title investigation before acquiring undeveloped leasehold acreage.

Seasonality

Generally, but not always, the demand and price levels for natural gas increase during colder winter months and decrease during warmer summer months. To lessen seasonal demand fluctuations, pipelines, utilities, local distribution companies, and industrial users utilize natural gas storage facilities and forward purchase some of their anticipated winter requirements during the summer. However, increased summertime demand for electricity has placed increased demand on storage volumes. Demand for crude oil and heating oil is also generally higher in the winter and the summer driving season — although oil prices are much more driven by global supply and demand. Seasonal anomalies, such as mild winters, sometimes lessen these fluctuations. The impact of seasonality on crude oil has been somewhat magnified by overall supply and demand economics attributable to the narrow margin of production capacity in excess of existing worldwide demand for crude oil.

Competition

The oil and gas industry is intensely competitive, particularly with respect to acquiring prospective oil and natural gas properties. We believe our leasehold position provides a sound foundation for a solid drilling program and our future growth. Our competitive position also depends on our geological, geophysical, and engineering expertise, and our financial resources. We believe the location of our acreage; our exploration, drilling, operational, and production expertise; available technologies; our financial resources and expertise; and the experience and knowledge of our management and technical teams enable us to compete effectively in our core operating areas. However, we face intense competition from a substantial number of major and independent oil and gas companies, which, in some cases, have larger technical staffs and greater financial and operational resources than we do. Many of these companies not only engage in the acquisition, exploration, development, and production of oil and natural gas reserves, but also have refining operations, market refined products, own drilling rigs, and generate electricity.

We also compete with other oil and gas companies in attempting to secure drilling rigs and other equipment and services necessary for the drilling, completion, and maintenance of wells. Consequently, we may face shortages or delays in securing these services from time to time. The oil and gas industry also faces competition from alternative fuel sources, including other fossil fuels such as coal and imported liquefied natural gas. Competitive conditions may also be affected by future new energy, climate-related, financial, and other policies, legislation, and regulations.

In addition, we compete for people, including experienced geologists, geophysicists, engineers, and other professionals and consultants. Throughout the oil and gas industry, the need to attract and retain talented people has grown at a time when the number of talented people available is constrained. We are not insulated from this resource constraint, and we must compete effectively in this market in order to be successful.

Recent Developments

In December 2011, we sold 2,840 net undeveloped acres in Weld County, Colorado to a third party. The sale included one marginally producing oil well in which the Company owned a 25% net working interest. The purchase price was approximately $4.5 million (approximately $1,600 per net acre).

Marketing and Pricing

We will derive revenue principally from the sale of oil and natural gas. As a result, our revenues are determined, to a large degree, by prevailing prices for crude oil and natural gas. We will sell our oil and natural gas on the open market at prevailing market prices or through forward delivery contracts. The market price for oil and natural gas is dictated by supply and demand, and we cannot accurately predict or control the price we may receive for our oil and natural gas.

Our revenues, cash flows, profitability and future rate of growth will depend substantially upon prevailing prices for oil and natural gas. Prices may also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. Lower prices may also adversely affect the value of our reserves and make it uneconomical for us to commence or continue production levels of natural gas and crude oil. Historically, the prices received for oil and natural gas have fluctuated widely. Among the factors that can cause these fluctuations are:

- changes in global supply and demand for oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC;
- the price and quantity of imports of foreign oil and natural gas;
- acts of war or terrorism;
- political conditions and events, including embargoes, affecting oil-producing activity;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil and natural gas inventories;
- weather conditions;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

From time to time, we enter into derivative contracts. These contracts economically hedge our exposure to decreases in the prices of oil and natural gas. Hedging arrangements may expose us to risk of significant financial loss in some circumstances including circumstances where:

- our production and/or sales of natural gas are less than expected;
- payments owed under derivative hedging contracts come due prior to receipt of the hedged month's production revenue; or
- the counter party to the hedging contract defaults on its contract obligations.

In addition, hedging arrangements may limit the benefit we would receive from increases in the prices for oil and natural gas. We cannot assure you that any hedging transactions we may enter into will adequately protect us from declines in the prices of oil and natural gas. On the other hand, where we choose not to engage in hedging transactions in the future, we may be more adversely affected by changes in oil and natural gas prices than our competitors who engage in hedging transactions.

Government Regulations

General. Our operations covering the exploration, production and sale of oil and natural gas are subject to various types of federal, state and local laws and regulations. The failure to comply with these laws and regulations can result in substantial penalties. These laws and regulations materially impact our operations and can affect our profitability. However, we do not believe that these laws and regulations affect us in a manner significantly different than our competitors. Matters regulated include permits for drilling operations, drilling and abandonment bonds, reports concerning operations, the spacing of wells and unitization and pooling of properties, restoration of surface areas, plugging and abandonment of wells, requirements for the operation of wells, and taxation of production. At various times, regulatory agencies have imposed price controls and limitations on production. In order to conserve supplies of oil and natural gas, these agencies have restricted the rates of flow of oil and natural gas wells below actual production capacity, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. Federal, state and local laws regulate production, handling, storage, transportation and disposal of oil and natural gas, by-products from oil and natural gas and other substances and materials produced or used in connection with oil and natural gas operations. While we believe we will be able to substantially comply with all applicable laws and regulations, the requirements of such laws and regulations are frequently changed. We cannot predict the ultimate cost of compliance with these requirements or their effect on our actual operations.

Federal Income Tax. Federal income tax laws significantly affect our operations. The principal provisions that affect us are those that permit us, subject to certain limitations, to deduct as incurred, rather than to capitalize and amortize, our domestic "intangible drilling and development costs" and to claim depletion on a portion of our domestic oil and natural gas properties based on 15% of our oil and natural gas gross income from such properties (up to an aggregate of 1,000 barrels per day of domestic crude oil and/or equivalent units of domestic natural gas).

Environmental, Health, and Safety Regulations. Our operations are subject to stringent federal, state, and local laws and regulations relating to the protection of the environment and human health and safety. Environmental laws and regulations may require that permits be obtained before drilling commences, restrict the types, quantities, and concentration of various substances that can be released into the environment in connection with drilling and production activities, govern the handling and disposal of waste material, and limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, and other protected areas, including areas containing endangered animal species. As a result, these laws and regulations may substantially increase the costs of exploring for, developing, or producing oil and gas and may prevent or delay the commencement or continuation of certain projects. In addition, these laws and regulations may impose substantial clean-up, remediation, and other obligations in the event of any discharges or emissions in violation of these laws and regulations. Further, legislative and regulatory initiatives related to global warming or climate change could have an adverse effect on our operations and the demand for oil and natural gas. See "Risk Factors — Risks Related to Oil and Gas Industry — Legislative and regulatory initiatives related to global warming and climate change could have an adverse effect on our operations and the demand for oil and natural gas."

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. For additional information about hydraulic fracturing and related regulatory matters, see "Risk Factors — Risks Related to Our Company". Federal and state legislation and regulatory initiatives related to hydraulic fracturing could result in increased costs and additional operating restrictions or delays in the completion of oil and gas wells.

Federal and state occupational safety and health laws require us to organize and maintain information about hazardous materials used, released, or produced in our operations. Some of this information must be provided to our employees, state and local governmental authorities, and local citizens. We are also subject to the requirements and reporting framework set forth in the federal workplace standards.

The discharge of oil, gas or other pollutants into the air, soil or water may give rise to liabilities to the government and third parties and may require us to incur costs to remedy discharges. Natural gas, oil or other pollutants, including salt water brine, may be discharged in many ways, including from a well or drilling equipment at a drill site, leakage from pipelines or other gathering and transportation facilities, leakage from storage tanks and sudden discharges from damage or explosion at natural gas facilities of oil and gas wells. Discharged hydrocarbons may migrate through soil to water supplies or adjoining property, giving rise to additional liabilities.

A variety of federal and state laws and regulations govern the environmental aspects of natural gas and oil production, transportation and processing and may, in addition to other laws, impose liability in the event of discharges, whether or not accidental, failure to notify the proper authorities of a discharge, and other noncompliance with those laws. Compliance with such laws and regulations may increase the cost of oil and gas exploration, development and production, although we do not anticipate that compliance will have a material adverse effect on our capital expenditures or earnings. Failure to comply with the requirements of the applicable laws and regulations could subject us to substantial civil and/or criminal penalties and to the temporary or permanent curtailment or cessation of all or a portion of our operations.

The Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, also known as the "superfund law," imposes liability, regardless of fault or the legality of the original conduct, on some classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of a disposal site or sites where the release occurred and companies that dispose or arrange for disposal of the hazardous substances found at the time. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and severable liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We could be subject to liability under CERCLA because our jointly owned drilling and production activities generate relatively small amounts of liquid and solid waste that may be subject to classification as hazardous substances under CERCLA.

The Resource Conservation and Recovery Act of 1976, as amended, or RCRA, is the principal federal statute governing the treatment, storage and disposal of hazardous wastes. RCRA imposes stringent operating requirements, and liability for failure to meet such requirements, on a person who is either a "generator" or "transporter" of hazardous waste or an "owner" or "operator" of a hazardous waste treatment, storage or disposal facility. At present, RCRA includes a statutory exemption that allows most oil and natural gas exploration and production waste to be classified as nonhazardous waste. A similar exemption is contained in many of the state counterparts to RCRA. As a result, we are not required to comply with a substantial portion of RCRA's requirements because our operations generate minimal quantities of hazardous wastes. At various times in the past, proposals have been made to amend RCRA to rescind the exemption that excludes oil and natural gas exploration and production wastes from regulation as hazardous waste. Repeal or modification of the exemption by administrative, legislative or judicial process, or modification of similar exemptions in applicable state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and would cause us to incur increased operating expenses.

The Oil Pollution Act of 1990, or OPA, and regulations thereunder impose a variety of regulations on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in United States waters. The OPA assigns liability to each responsible party for oil removal costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of federal safety, construction or operating regulations. Few defenses exist to the liability imposed by OPA. In addition, to the extent we acquire offshore leases and those operations affect state waters, we may be subject to additional state and local clean-up requirements or incur liability under state and local laws. OPA also imposes ongoing requirements on responsible parties, including proof of financial responsibility to cover at least some costs in a potential spill. We cannot predict whether the financial responsibility requirements under the OPA amendments will adversely restrict our proposed operations or impose substantial additional annual costs to us or otherwise materially adversely affect us. The impact, however, should not be any more adverse to us than it will be to other similarly situated owners or operators.

The Federal Water Pollution Control Act Amendments of 1972 and 1977, or Clean Water Act, imposes restrictions and controls on the discharge of produced waters and other wastes into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters and to conduct construction activities in waters and wetlands. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the crude oil and natural gas industry into certain coastal and offshore waters. Further, the Environmental Protection Agency, or EPA, has adopted regulations requiring certain crude oil and natural gas exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans. The Clean Water Act and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges of crude oil and other pollutants and impose liability on parties responsible for those discharges for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. We believe that our operations comply in all material respects with the requirements of the Clean Water Act and state statutes enacted to control water pollution.

Underground injection is the subsurface placement of fluid through a well, such as the reinjection of brine produced and separated from crude oil and natural gas production. The Safe Drinking Water Act of 1974, as amended, establishes a regulatory framework for underground injection, with the main goal being the protection of usable aquifers. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. Hazardous-waste injection well operations are strictly controlled, and certain wastes, absent an exemption, cannot be injected into underground injection control wells. Failure to abide by our permits could subject us to civil or criminal enforcement. We believe that we are in compliance in all material respects with the requirements of applicable state underground injection control programs and our permits.

The Clean Air Act of 1963 and subsequent extensions and amendments, known collectively as the Clean Air Act, and state air pollution laws adopted to fulfill its mandate provide a framework for national, state and local efforts to protect air quality. Our operations utilize equipment that emits air pollutants which may be subject to federal and state air pollution control laws. These laws require utilization of air emissions abatement equipment to achieve prescribed emissions limitations and ambient air quality standards, as well as operating permits for existing equipment and construction permits for new and modified equipment. We believe that we are in compliance in all material respects with the requirements of applicable federal and state air pollution control laws. Over the next several years, we may be required to incur capital expenditures for air pollution control equipment or other air emissions-related issues. For example, on July 28, 2011, the EPA proposed a range of new regulations that would establish new air emission controls for oil and natural gas production, including, among other things, the application of reduced emission completion techniques, referred to as "green completions," for completion of newly drilled and fractured wells in addition to establishing specific requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment. Final action on the proposed rules is expected no later than April 3, 2012. If this action is finalized, we do not believe that such requirements will have a material adverse effect on our operations.

There are numerous state laws and regulations in the states in which we operate which relate to the environmental aspects of our business. These state laws and regulations generally relate to requirements to remediate spills of deleterious substances associated with oil and gas activities, the conduct of salt water disposal operations, and the methods of plugging and abandonment of oil and gas wells which have been unproductive. Numerous state laws and regulations also relate to air and water quality.

We do not believe that our environmental risks will be materially different from those of comparable companies in the oil and gas industry. We believe our present activities substantially comply, in all material respects, with existing environmental laws and regulations. Nevertheless, we cannot assure you that environmental laws will not result in a curtailment of production or material increase in the cost of production, development or exploration or otherwise adversely affect our financial condition and results of operations. Although we maintain liability insurance coverage for liabilities from pollution, environmental risks generally are not fully insurable.

In addition, because we have acquired and may acquire interests in properties that have been operated in the past by others, we may be liable for environmental damage, including historical contamination, caused by such former operators. Additional liabilities could also arise from continuing violations or contamination not discovered during our assessment of the acquired properties.

Federal Leases. For those operations on federal oil and gas leases, such operations must comply with numerous regulatory restrictions, including various non-discrimination statutes, and certain of such operations must be conducted pursuant to certain on-site security regulations and other permits issued by various federal agencies. In addition, on federal lands in the United States, the Minerals Management Service, or MMS, prescribes or severely limits the types of costs that are deductible transportation costs for purposes of royalty valuation of production sold off the lease. In particular, MMS prohibits deduction of costs associated with marketer fees, cash out and other pipeline imbalance penalties, or long-term storage fees. Further, the MMS has been engaged in a process of promulgating new rules and procedures for determining the value of crude oil produced from federal lands for purposes of calculating royalties owed to the government. The natural gas and crude oil industry as a whole has resisted the proposed rules under an assumption that royalty burdens will substantially increase. We cannot predict what, if any, effect any new rule will have on our operations.

Some of our operations are conducted on federal lands pursuant to oil and gas leases administered by the Bureau of Land Management, or BLM. These leases contain relatively standardized terms and require compliance with detailed regulations and orders, which are subject to change. In addition to permits required from other regulatory agencies, lessees must obtain a permit from the BLM before drilling and comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, the valuation of production and payment of royalties, the removal of facilities, and the posting of bonds to ensure that lessee obligations are met. Under certain circumstances, the BLM may require our operations on federal leases to be suspended or terminated.

In May 2010, the BLM adopted changes to its oil and gas leasing program that require, among other things, a more detailed environmental review prior to leasing oil and natural gas resources, increased public engagement in the development of master leasing and development plans prior to leasing areas where intensive new oil and gas development is anticipated, and a comprehensive parcel review process. These changes may increase the amount of time and regulatory costs necessary to obtain oil and gas leases administered by the BLM.

Other Laws and Regulations. Various laws and regulations often require permits for drilling wells and also cover spacing of wells, the prevention of waste of natural gas and oil including maintenance of certain gas/oil ratios, rates of production and other matters. The effect of these laws and regulations, as well as other regulations that could be promulgated by the jurisdictions in which we have production, could be to limit the number of wells that could be drilled on our properties and to limit the allowable production from the successful wells completed on our properties, thereby limiting our revenues.

To date we have not experienced any materially adverse effect on our operations from obligations under environmental, health, and safety laws and regulations. We believe that we are in substantial compliance with currently applicable environmental, health, and safety laws and regulations, and that continued compliance with existing requirements would not have a materially adverse impact on us.

Glossary of Oil and Natural Gas Terms

The following is a description of the meanings of some of the oil and natural gas industry terms used in this report.

bbl. Stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to crude oil or other liquid hydrocarbons.

Bcf. Billion cubic feet of natural gas.

boe. Barrels of crude oil equivalent, determined using the ratio of six mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids.

boe/d. boe per day.

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Condensate. Hydrocarbons which are in the gaseous state under reservoir conditions and which become liquid when temperature or pressure is reduced. A mixture of pentanes and higher hydrocarbons.

Development well. A well drilled within the proved area of a natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.

Drilling locations. Total gross locations specifically quantified by management to be included in our multi-year drilling activities on existing acreage. Our actual drilling activities may change depending on the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, drilling results and other factors.

Dry hole. A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

Exploratory well. A well drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend a known reservoir.

Field. An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Formation. An identifiable layer of rocks named after its geographical location and dominant rock type.

Lease. A legal contract that specifies the terms of the business relationship between an energy company and a landowner or mineral rights holder on a particular tract of land.

Leasehold. Mineral rights leased in a certain area to form a project area.

Mbbls. Thousand barrels of crude oil or other liquid hydrocarbons.

Mboe. Thousand barrels of crude oil equivalent, determined using the ratio of six mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids.

Mcf. Thousand cubic feet of natural gas.

Mcfe. Thousand cubic feet equivalent, determined using the ratio of six mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids.

MMbbls. Million barrels of crude oil or other liquid hydrocarbons.

MMboe. Million barrels of crude oil equivalent, determined using the ratio of six mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids.

MMbtu. Million British Thermal Units.

MMcf. Million cubic feet of natural gas.

Net acres, net wells, or net reserves. The sum of the fractional working interest owned in gross acres, gross wells, or gross reserves, as the case may be.

Net barrel of production. The sum of the fractional revenue interest in gross production owned by the company.

ngl. Natural gas liquids, or liquid hydrocarbons found in association with natural gas.

Overriding royalty interest. Is similar to a basic royalty interest except that it is created out of the working interest. For example, an operator possesses a standard lease providing for a basic royalty to the lesser or mineral rights owner of 1/8 of 8/8. This then entitles the operator to retain 7/8 of the total oil and natural gas produced. The 7/8 in this case is the 100% working interest the operator owns. This operator may assign his working interest to another operator subject to a retained 1/8 overriding royalty. This would then result in a basic royalty of 1/8, an overriding royalty of 1/8 and a working interest of 3/4. Overriding royalty interest owners have no obligation or responsibility for developing and operating the property. The only expenses borne by the overriding royalty owner are a share of the production or severance taxes and sometimes costs incurred to make the oil or gas salable.

Plugging and abandonment. Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.

Present value of future net revenues (PV-10). The present value of estimated future revenues to be generated from the production of estimated net proved reserves, net of estimated production and future development costs, using the simple 12 month first of month average price and current costs (unless such prices or costs are subject to change pursuant to contractual provisions), without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%. While this measure does not include the effect of income taxes as it would in the use of the standardized measure calculation, it does provide an indicative representation of the relative value of Recovery Energy on a comparative basis to other companies and from period to period.

Production. Natural resources, such as oil or gas, taken out of the ground.

Proved reserves. The quantities of oil, natural gas and natural gas liquids, which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs under existing economic conditions and operating conditions.

Proved developed oil and gas reserves. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved undeveloped reserves. Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Probable Reserves. Probable reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated proved plus probable reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50-percent probability that the actual quantities recovered will equal or exceed the 2P estimate.

Possible Reserves. Possible reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than probable reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of proved plus probable plus possible reserves (3P), which is equivalent to the high estimate scenario. In this context, when probabilistic methods are used, there should be at least a 10-percent probability that the actual quantities recovered will equal or exceed the 3P estimate.

Productive well. A well that is found to be capable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

Project. A targeted development area where it is probable that commercial gas can be produced from new wells.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Recompletion. The process of re-entering an existing well bore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

Reserves. Oil, natural gas and gas liquids thought to be accumulated in known reservoirs.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible nature gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.

Secondary Recovery. A recovery process that uses mechanisms other than the natural pressure of the reservoir, such as gas injection or water flooding, to produce residual oil and natural gas remaining after the primary recovery phase.

Shut-in. A well that has been capped (having the valves locked shut) for an undetermined amount of time. This could be for additional testing, could be to wait for pipeline or processing facility, or a number of other reasons.

Standardized measure. The present value of estimated future cash inflows from proved oil and natural gas reserves, less future development, abandonment, production and income tax expenses, discounted at 10% per annum to reflect timing of future cash flows and using the same pricing assumptions as were used to calculate PV-10. Standardized measure differs from PV-10 because standardized measure includes the effect of future income taxes.

Successful. A well is determined to be successful if it is producing oil or natural gas, or awaiting hookup, but not abandoned or plugged.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Water flood. A method of secondary recovery in which water is injected into the reservoir formation to displace residual oil and enhance hydrocarbon recovery.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.

Item 1A. RISK FACTORS

In addition to other matters identified or described by us from time to time in filings with the SEC, there are several important factors that could cause our future results to differ materially from historical results or trends, results anticipated or planned by us, or results that are reflected from time to time in any forward-looking statement. Some of these important factors, but not necessarily all important factors, include the following:

Risks related to our company

We have historically incurred losses and cannot assure investors as to future profitability. We have historically incurred losses from operations during our history in the oil and natural gas business. As of December 31, 2011, we had a cumulative deficit of approximately $68.0 million. Many of our properties are in the exploration stage, and to date we have established a limited volume of proved reserves on our properties. Our ability to be profitable in the future will depend on successfully implementing our acquisition, exploration, development and production activities, all of which are subject to many risks beyond our control. Even if we become profitable on an annual basis, we cannot assure you that our profitability will be sustainable or increase on a periodic basis. In addition, should we be unable to continue as a going concern, realization of assets and settlement of liabilities in other than the normal course of business may be at amounts significantly different from those in the financial statements included in this annual report.

Our credit agreements mature on June 30, 2013, and our lender can foreclose on several of our properties if we do not pay off or refinance our approximately $21 million of loans. Some of our oil and gas properties are pledged as collateral for our credit agreements. Failure to repay these loans at maturity or refinance them could cause a default under the credit agreements and allow the lender to foreclose on these properties.

Currently, the majority of our revenue after field level operating expenses is required to be paid to our lender as debt service and our lenders have allowed us to defer some of these payments. In 2011, our lender has deferred the payment of approximately $2 million of revenue toward debt service, and there can be no assurance that our lender will continue to permit deferrals. As of December 31, 2011, we had working capital of $1.3 million. We sold our Grover field property for $4.5 million in January 2012 and will seek to obtain additional capital through the sale of our securities, the successful deployment of our cash on hand, bank lines of credit, joint ventures, and project financing. Consequently, there can be no assurance we will be able to obtain continued access to capital as and when needed or, if so, that the terms of any available financing will be subject to commercially reasonable terms. If we are unable to access additional capital in significant amounts as needed, we may not be able to develop our current prospects and properties, may have to forfeit our interest in certain prospects and may not otherwise be able to develop our business. In such an event, our stock price could be materially adversely affected.

We will require additional capital in order to achieve commercial success and, if necessary, to finance future losses from operations as we endeavor to build revenue, but we do not have any commitments to obtain such capital and we cannot assure you that we will be able to obtain adequate capital as and when required. The business of oil and gas acquisition, drilling and development is capital intensive and the level of operations attainable by an oil and gas company is directly linked to and limited by the amount of available capital. We believe that our ability to achieve commercial success and our continued growth will be dependent on our continued access to capital either through the additional sale of our equity or debt securities, bank lines of credit, project financing, joint ventures or cash generated from oil and gas operations.

We do not have a significant operating history and, as a result, there is a limited amount of information about us on which to make an investment decision. In January 2010, we acquired our first oil and gas prospects and received our first revenues from oil and gas production in February 2010. Accordingly, there is little operating history upon which to judge our business strategy, our management team or our current operations.

We have limited management and staff and will be dependent upon partnering arrangements. We have ten employees. We intend to use the services of independent consultants and contractors to perform various professional services, including reservoir engineering, land, legal, environmental and tax services. We will also pursue alliances with partners in the areas of geological and geophysical services and prospect generation, evaluation and prospect leasing. Our dependence on third party consultants and service providers creates a number of risks, including but not limited to:

- the possibility that such third parties may not be available to us as and when needed; and
- the risk that we may not be able to properly control the timing and quality of work conducted with respect to our projects.

If we experience significant delays in obtaining the services of such third parties or poor performance by such parties, our results of operations and stock price could be materially adversely affected.

The loss of our chief executive officer could adversely affect us. We are dependent on the extensive experience of our chief executive officer to implement our acquisition and growth strategy. The loss of the services of this individual could have a negative impact on our operations and our ability to implement our strategy.

In an audit of our internal controls over financial reporting, both Recovery and our independent registered accounting firm concluded that our internal controls were ineffective as of December 31, 2011. As discussed in Item 9.A CONTROLS AND PROCEDURES, we noted, and our independent registered accounting firm concurred, that the following material weaknesses in our internal control over financial reporting existed as of December 31, 2011:

- Insufficient independent internal review and approval of critical accounting schedules used in the preparation of financial statements.
- The financial statement close process did not permit timely preparation of necessary financial information and there is inadequate documentation of internal controls for some assertions in certain significant accounts..
- Lack of effective controls over general ledger processing, spreadsheets and data back-up.

We are designing and implementing new internal controls to address these issues; however, we can provide no assurance as to when such new controls may be fully functional or whether such controls will be sufficient to prevent future material weaknesses in our internal controls and systems.

In addition to acquiring producing properties, we may also grow our business through the acquisition and development of exploratory oil and gas prospects, which is the riskiest method of establishing oil and gas reserves. In addition to acquiring producing properties, we may acquire, drill and develop exploratory oil and gas prospects that are profitable to produce. Developing exploratory oil and gas properties requires significant capital expenditures and involves a high degree of financial risk. The budgeted costs of drilling, completing, and operating exploratory wells are often exceeded and can increase significantly when drilling costs rise. Drilling may be unsuccessful for many reasons, including title problems, weather, cost overruns, equipment shortages, and mechanical difficulties. Moreover, the successful drilling or completion of an exploratory oil or gas well does not ensure a profit on investment. Exploratory wells bear a much greater risk of loss than development wells. We cannot assure you that our exploration, exploitation and development activities will result in profitable operations. If we are unable to successfully acquire and develop exploratory oil and gas prospects, our results of operations, financial condition and stock price may be materially adversely affected.

Hedging transactions may limit our potential gains or result in losses. In order to manage our exposure to price risks in the marketing of our oil and natural gas, from time to time we may enter into derivative contracts that economically hedge our oil and gas price on a portion of our production. These contracts may limit our potential gains if oil and natural gas prices were to rise substantially over the price established by the contract. In addition, such transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received;
- our production and/or sales of oil or natural gas are less than expected;
- payments owed under derivative hedging contracts come due prior to receipt of the hedged month's production revenue; or
- the other party to the hedging contract defaults on its contract obligations.

Hedging transactions we may enter into may not adequately protect us from declines in the prices of oil and natural gas. Further, where we choose not to engage in hedging transactions, we may be more adversely affected by changes in oil and natural gas prices than our competitors who engage in hedging transactions. In addition, the counterparties under our derivatives contracts may fail to fulfill their contractual obligations to us.

We may have difficulty managing growth in our business, which could adversely affect our financial condition and results of operations. Significant growth in the size and scope of our operations could place a strain on our financial, technical, operational and management resources. The failure to continue to upgrade our technical, administrative, operating and financial control systems or the occurrences of unexpected expansion difficulties, including the failure to recruit and retain experienced managers, geologists, engineers and other professionals in the oil and gas industry could have a material adverse effect on our business, financial condition and results of operations and our ability to timely execute our business plan.

The actual quantities and present value of our proved reserves may be lower than we have estimated. In addition, the present value of future net revenues from our proved reserves will not necessarily be the same as the current market value of our estimated oil and natural gas reserves. This annual report contains estimates of our proved oil and natural gas reserves and the estimated future net revenues from these reserves contained in our filings with the SEC. The December 31, 2011, reserve estimate was prepared by our Senior Reserve Engineer and audited by RE Davis. The process of estimating oil and natural gas reserves is complex and requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Accordingly, these estimates are inherently imprecise. Actual future production, oil and natural gas prices, revenues, taxes, development and operating expenses, and quantities of recoverable oil and natural gas reserves most likely will vary from these estimates and vary over time. Such variations may be significant and could materially affect the estimated quantities and present value of our proved reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development drilling, results of secondary and tertiary recovery applications, prevailing oil and natural gas prices and other factors, many of which are beyond our control. You should also not assume that our initial rates of production of our wells will lead to greater overall production over the life of the wells, or that early results suggesting lack of reservoir continuity will prove to be accurate.

You should not assume that the present value of future net revenues referred to in this annual report is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves are generally based on the un-weighted average of the closing prices during the first day of each of the twelve months preceding the end of the fiscal year. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. Any change in consumption by oil or natural gas purchasers or in governmental regulations or taxation will also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of our oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor nor does it reflect discount factors used in the market place for the purchase and sale of oil and natural gas.

Properties that we acquire may not produce oil or natural gas as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against them, which could cause us to incur losses. One of our growth strategies is to pursue selective acquisitions of undeveloped leaseholder oil and natural gas reserves. If we choose to pursue an acquisition, we will perform a review of the target properties; however, these reviews are inherently incomplete. Generally, it is not feasible to review in depth every individual property involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. We may not perform an inspection on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, we may not be able to obtain effective contractual protection against all or part of those problems, and we may assume environmental and other risks and liabilities in connection with the acquired properties.

Our large inventory of undeveloped acreage and large percentage of undeveloped proved reserves may create additional economic risk. Our success is largely dependent upon our ability to develop our large inventory of future drilling locations, undeveloped acreage and undeveloped reserves. As of December 31, 2011, approximately 47% of our total proved reserves were undeveloped. To the extent our drilling results are not as successful as we anticipate, natural gas and oil prices decline, or sufficient funds are not available to drill these locations and reserves, we may not capture the expected or projected value of these properties. In addition, delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic.

Our revenue, profitability, cash flow, future growth and ability to borrow funds or obtain additional capital, as well as the carrying value of our properties, are substantially dependent on prevailing prices of oil and natural gas. If oil and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and natural gas properties, negatively impacting the trading value of our securities. There is a risk that we will be required to write down the carrying value of our oil and gas properties, which would reduce our earnings and stockholders' equity. We follow the full cost method of accounting for oil and gas operations whereby all costs related to exploration and development of oil and gas properties are initially capitalized into a single cost center, known as a full cost pool. We record all capitalized costs into a single cost center as all operations are conducted within the United States. Such costs include land acquisition costs, geological and geophysical expenses, carry charges on non-producing properties, and costs of drilling directly related to acquisition and exploration activities. Proceeds from property sales are generally credited to the full cost pool, with no gain or loss recognized, unless such a sale would significantly alter the relationship between capitalized costs and the proved reserves attributable to these costs. A significant alteration would typically involve a sale of 25% or more of the proved reserves related to a single full cost pool.

Additional write downs could occur if oil and gas prices decline or if we have substantial downward adjustments to our estimated proved reserves, increases in our estimates of development costs or deterioration in our drilling results.

All of our producing properties and operations are located in the DJ Basin region, making us vulnerable to risks associated with operating in one major geographic area. All of our estimated proved reserves at December 31, 2011, and our 2010 and 2011 sales were generated in the DJ Basin in southeastern Wyoming, northeastern Colorado and southwestern Nebraska. As a result, we may be disproportionately exposed to the impact of delays or interruptions of production from these wells caused by transportation capacity constraints, curtailment of production, availability of equipment, facilities, personnel or services, significant governmental regulation, natural disasters, adverse weather conditions, plant closures for scheduled maintenance or interruption of transportation of oil or natural gas produced from the wells in this area. In addition, the effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and gas producing areas such as the DJ Basin, which may cause these conditions to occur with greater frequency or magnify the effect of these conditions. Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations.

Unless we find new oil and gas reserves, our reserves and production will decline, which would materially and adversely affect our business, financial condition and results of operations. Producing oil and gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Thus, our future oil and gas reserves and production and, therefore, our cash flow and revenue are highly dependent on our success in efficiently obtaining reserves and acquiring additional recoverable reserves. We may not be able to develop, find or acquire reserves to replace our current and future production at costs or other terms acceptable to us, or at all, in which case our business, financial condition and results of operations would be materially and adversely affected.

Part of our strategy involves drilling in existing or emerging shale plays using available horizontal drilling and completion techniques. The results of our planned exploratory and development drilling in these plays are subject to drilling and completion technique risks and drilling results may not meet our expectations for reserves or production. As a result, we may incur material write-downs and the value of our undeveloped acreage could decline if drilling results are unsuccessful. Operations in the Niobrara shale involve utilizing drilling and completion techniques as developed by ourselves and our service providers. Risks that we face while drilling include, but are not limited to, landing our wellbore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running our casing the entire length of the wellbore and being able to run tools and other equipment consistently through the horizontal wellbore. Risks that we face while completing our wells include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools the entire length of the wellbore during completion operations and successfully cleaning out the wellbore after completion of the final fracture stimulation stage.

Our experience with horizontal drilling utilizing the latest drilling and completion techniques specifically in the Niobrara is limited. Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems and limited takeaway capacity or otherwise, and/or natural gas and oil prices decline, the return on our investment in these areas may not be as attractive as we anticipate and we could incur material write-downs of unevaluated properties and the value of our undeveloped acreage could decline in the future.

The unavailability or high cost of drilling rigs, equipment supplies or personnel could adversely affect our ability to execute our exploration and development plans. The oil and gas industry is cyclical and, from time to time, there are shortages of drilling rigs, equipment, supplies or qualified personnel. During these periods, the costs of rigs, equipment and supplies may increase substantially and their availability may be limited. In addition, the demand for, and wage rates of, qualified personnel, including drilling rig crews, may rise as the number of rigs in service increases. The higher prices of oil and gas during the last several years have resulted in shortages of drilling rigs, equipment and personnel, which have resulted in increased costs and shortages of equipment in the areas where we operate. If drilling rigs, equipment, supplies or qualified personnel are unavailable to us due to excessive costs or demand or otherwise, our ability to execute our exploration and development plans could be materially and adversely affected and, as a result, our financial condition and results of operations could be materially and adversely affected.

Covenants in our credit agreements impose significant restrictions and requirements on us. Our three credit agreements contain a number of covenants imposing significant restrictions on us, including restrictions on our repurchase of, and payment of dividends on, our capital stock and limitations on our ability to incur additional indebtedness, make investments, engage in transactions with affiliates, sell assets and create liens on our assets. These restrictions may affect our ability to operate our business, to take advantage of potential business opportunities as they arise and, in turn, may materially and adversely affect our business, financial conditions and results of operations.

We could be required to pay liquidated damages to some of our investors if we fail to maintain the effectiveness of a prior registration statement. We could default and accrue liquidated damages under registration rights agreements covering approximately 3.2 million shares of our common stock if we fail to maintain the effectiveness of a prior registration statement as required in the agreements. In such case, we would be required to pay monthly liquidated damages of up to $228,050. The maximum aggregate liquidated damages are capped at $1,368,300. If we do not make a monthly payment within seven days after the date payable, we are required to pay interest at an annual rate of 18% on the unpaid amount. If we default under the registration rights agreement and accrue liquidated damages, we could be required to either raise additional outside funds through financing or curtail or cease operations.

We are exposed to operating hazards and uninsured risks. Our operations are subject to the risks inherent in the oil and natural gas industry, including the risks of:

- fire, explosions and blowouts;
- pipe failure;
- abnormally pressured formations; and
- environmental accidents such as oil spills, natural gas leaks, ruptures or discharges of toxic gases, brine or well fluids into the environment (including groundwater contamination).

These events may result in substantial losses to us from:

- injury or loss of life;
- severe damage to or destruction of property, natural resources and equipment;
- pollution or other environmental damage;
- clean-up responsibilities;
- regulatory investigation;
- penalties and suspension of operations; or
- attorney's fees and other expenses incurred in the prosecution or defense of litigation.

We maintain insurance against some, but not all, of these risks. We cannot assure you that our insurance will be adequate to cover these losses or liabilities. We do not carry business interruption insurance. Losses and liabilities arising from uninsured or underinsured events may have a material adverse effect on our financial condition and operations.

The producing wells in which we have an interest occasionally experience reduced or terminated production. These curtailments can result from mechanical failures, contract terms, pipeline and processing plant interruptions, market conditions and weather conditions. These curtailments can last from a few days to many months.

We may be subject to risks in connection with acquisitions, and the integration of significant acquisitions may be difficult. We periodically evaluate acquisitions of reserves, properties, prospects and leaseholds and other strategic transactions that appear to fit within our overall business strategy. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their appropriate differentials;
- development and operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and potential recoverable reserves. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an "as is" basis.

Significant acquisitions and other strategic transactions may involve other risks, including:

- diversion of our management's attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;
- challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with those of ours while carrying on our ongoing business;
- difficulty associated with coordinating geographically separate organizations;
- challenge of attracting and retaining personnel associated with acquired operations; and
- failure to realize the full benefit that we expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition, or to realize these benefits within the expected time frame.

The process of integrating operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer.

Prospects that we decide in which to participate may not yield oil or natural gas in commercially viable quantities or quantities sufficient to meet our targeted rate of return. A prospect is a property in which we own an interest and have what we believe, based on available seismic and geological information, to be indications of oil or natural gas. Our prospects are in various stages of evaluation, ranging from a prospect that is ready to be drilled to a prospect that will require substantial additional seismic data processing and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion cost or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analysis we perform using data from other wells, more fully explored prospects or producing fields will be useful in predicting the characteristics and potential reserves associated with our drilling prospects.

Our reserve estimates will depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves. The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and the calculation of the present value of reserves shown in these reports.

In order to prepare reserve estimates in its reports, our independent petroleum consultant projected production rates and timing of development expenditures. Our independent petroleum consultant also analyzed available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary and may not be in our control. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Therefore, estimates of oil and natural gas reserves are inherently imprecise.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will most likely vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, our independent petroleum consultant may adjust estimates of proved reserves to reflect production history, drilling results, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

Risks relating to the oil and gas industry

Oil and natural gas prices are highly volatile, and lower prices will negatively affect our financial condition, planned capital expenditures and results of operations. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production and the levels of our production depend on numerous factors beyond our control. These factors include the following:

- changes in global supply and demand for oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC;
- the price and quantity of imports of foreign oil and natural gas;
- acts of war or terrorism;
- political conditions and events, including embargoes, affecting oil-producing activity;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil and natural gas inventories;
- weather conditions;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels; and
- market concerns about global warming or changes in governmental policies and regulations due to climate change initiatives.

Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

Our revenues, operating results, profitability and future rate of growth depend primarily upon the prices we receive for oil and, to a lesser extent, natural gas that we sell. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. In addition, we may need to record asset carrying value write-downs if prices fall. A significant decline in the prices of natural gas or oil could adversely affect our financial position, financial results, cash flows, access to capital and ability to grow.

Our industry is highly competitive which may adversely affect our performance, including our ability to participate in ready to drill prospects in our core areas. We operate in a highly competitive environment. In addition to capital, the principal resources necessary for the exploration and production of oil and natural gas are:

- leasehold prospects under which oil and natural gas reserves may be discovered;
- drilling rigs and related equipment to explore for such reserves; and
- Knowledgeable personnel to conduct all phases of oil and natural gas operations.

We must compete for such resources with both major oil and natural gas companies and independent operators. Virtually all of these competitors have financial and other resources substantially greater than ours. We cannot assure you that such materials and resources will be available when needed. If we are unable to access material and resources when needed, we risk suffering a number of adverse consequences, including:

- the breach of our obligations under the oil and gas leases by which we hold our prospects and the potential loss of those leasehold interests;
- loss of reputation in the oil and gas community;
- a general slow down in our operations and decline in revenue; and
- decline in market price of our common shares.

Legislative and regulatory initiatives related to global warming and climate change could have an adverse effect on our operations and the demand for oil and natural gas. In December 2009, the EPA determined that emissions of carbon dioxide, methane and other "greenhouse gases" present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the Clean Air Act, or CAA. The EPA recently adopted two sets of rules regulating greenhouse gas emissions under the CAA, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and the other of which regulates emissions of greenhouse gases from certain large stationary sources, effective January 2, 2011. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, including petroleum refineries, on an annual basis, beginning in 2011 for emissions occurring after January 1, 2010, as well as certain onshore oil and natural gas production facilities, on an annual basis, beginning in 2012 for emissions occurring in 2011.

In addition, the United States Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil, NGLs, and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays in the completion of oil and natural gas wells.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing techniques in many of our drilling and completion programs. The process is typically regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the federal Safe Drinking Water Act. In addition, legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing under the Safe Drinking Water Act and to require disclosure of the chemicals used in the hydraulic fracturing process. Under the proposed legislation, this information would be available to the public via the internet, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. At the state level, some states have adopted, and other states are considering adopting legal requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities. If new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. Moreover, the EPA has announced that it will develop effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms.

We are subject to numerous laws and regulations that can adversely affect the cost, manner or feasibility of doing business. Our operations are subject to extensive federal, state and local laws and regulations relating to the exploration, production and sale of oil and natural gas, and operating safety. Future laws or regulations, any adverse change in the interpretation of existing laws and regulations or our failure to comply with existing legal requirements may result in substantial penalties and harm to our business, results of operations and financial condition. We may be required to make large and unanticipated capital expenditures to comply with governmental regulations, such as:

- land use restrictions;
- lease permit restrictions;
- drilling bonds and other financial responsibility requirements, such as plugging and abandonment bonds;
- spacing of wells;
- unitization and pooling of properties;
- safety precautions;
- operational reporting; and
- taxation.

Under these laws and regulations, we could be liable for:

- personal injuries;
- property and natural resource damages;
- well reclamation cost; and
- governmental sanctions, such as fines and penalties.

Our operations could be significantly delayed or curtailed and our cost of operations could significantly increase as a result of regulatory requirements or restrictions. We are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations. It is also possible that a portion of our oil and gas properties could be subject to eminent domain proceedings or other government takings for which we may not be adequately compensated. See “Business--Government Regulations*”* for a more detailed description of our regulatory risks.

Our operations may incur substantial expenses and resulting liabilities from compliance with environmental laws and regulations. Our oil and natural gas operations are subject to stringent federal, state and local laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations:

- require the acquisition of a permit before drilling commences;
- restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities, including new environmental regulations governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and
- impose substantial liabilities for pollution resulting from our operations.

Failure to comply with these laws and regulations may result in:

- the assessment of administrative, civil and criminal penalties;
- incurrence of investigatory or remedial obligations; and
- the imposition of injunctive relief.

Changes in environmental laws and regulations occur frequently and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to reach and maintain compliance and may otherwise have a material adverse effect on our industry in general and on our own results of operations, competitive position or financial condition. Under these environmental laws and regulations, we could be held strictly liable for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or contamination or if our operations met previous standards in the industry at the time they were performed. Our permits require that we report any incidents that cause or could cause environmental damages. See *“Business—Government Regulations”* for a more detailed description of our environmental risks.

Risks relating to our common stock

There is a limited public market for our shares and we cannot assure you that an active trading market or a specific share price will be established or maintained.

Our common stock trades on the Nasdaq Global Market, generally in small volumes each day. The value of our common stock could be affected by:

- actual or anticipated variations in our operating results;
- changes in the market valuations of other oil and gas companies;
- announcements by us or our competitors of significant acquisitions, strategic partnerships, joint ventures or capital commitments;
- Adoption of new accounting standards affecting our industry;
- Additions or departures of key personnel;
- sales of our common stock or other securities in the open market;
- changes in financial estimates by securities analysts;
- conditions or trends in the market in which we operate;
- changes in earnings estimates and recommendations by financial analysts;
- our failure to meet financial analysts' performance expectations; and
- other events or factors, many of which are beyond our control.

In a volatile market, you may experience wide fluctuations in the market price of our securities. These fluctuations may have an extremely negative effect on the market price of our common stock and may prevent you from obtaining a market price equal to your purchase price when you attempt to sell our common stock in the open market. In these situations, you may be required either to sell at a market price which is lower than your purchase price, or to hold our common stock for a longer period of time than you planned. An inactive market may also impair our ability to raise capital by selling shares of capital stock and may impair our ability to acquire other companies or oil and gas properties by using common stock as consideration.

Securities analysts may not initiate coverage of our shares or may issue negative reports, which may adversely affect the trading price of the shares.

We cannot assure you that securities analysts will cover our company. If securities analysts do not cover our company, this lack of coverage may adversely affect the trading price of our shares. The trading market for our shares will rely in part on the research and reports that securities analysts publish about us and our business. If one or more of the analysts who cover our company downgrades our shares, the trading price of our shares may decline. If one or more of these analysts ceases to cover our company, we could lose visibility in the market, which, in turn, could also cause the trading price of our shares to decline. Further, because of our small market capitalization, it may be difficult for us to attract securities analysts to cover our company, which could significantly and adversely affect the trading price of our shares.

Item 1B. UNRESOLVED STAFF COMMENTS

None

Item 3. LEGAL PROCEEDINGS

There are no material pending legal proceedings to which we or our properties are subject.

Item 4. MINE SAFETY DISCLOSURES

Not applicable

PART II

Item 5. MARKET FOR COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Recent Market Prices

On November 2, 2011 our common stock began trading on the Nasdaq Capital Market under the symbol "RECV." Between September 25, 2009 and November 1, 2011 our stock traded on the OTC Market under the symbol "RECV.OB."

The following table shows the high and low reported sales prices of our common stock for the periods indicated. Effective October 19, 2011 we completed a 1:4 reverse stock split, and stock prices prior to such date have been adjusted to reflect the effect of the stock split.

		High		Low
2011				
Fourth Quarter	$	7.00		2.99
Third Quarter	$	11.00		4.88
Second Quarter	$	13.00		8.80
First Quarter	$	15.56	$	7.80
2010				
Fourth Quarter	$	10.00	$	7.24
Third Quarter	$	10.00	$	6.00
Second Quarter	$	16.00	$	1.00
First Quarter	$	22.00	$	8.20
2009				
Fourth Quarter	$	23.00	$	12.00
September 25, 2009 through September 30, 2009	$	24.00	$	17.00

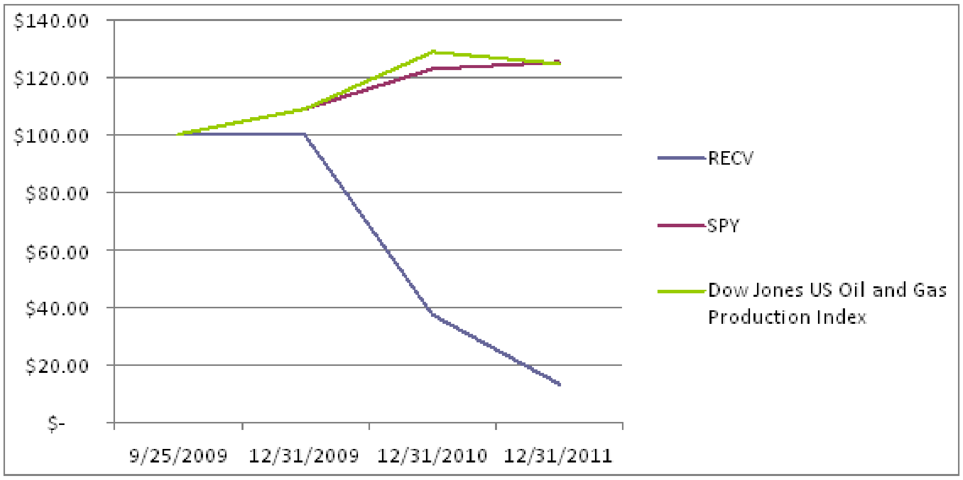
On March 13, 2012, there were approximately 28 owners of record of our common stock.

Dividend Policy

We have never paid any cash dividends on our common stock and do not anticipate paying any dividends in the foreseeable future. Our current business plan is to retain any future earnings to finance the expansion and development of our business. Any future determination to pay cash dividends will be at the discretion of our board of directors, and will be dependent upon our financial condition, results of operations, capital requirements and other factors as our board may deem relevant at that time.

Stock Performance Graph

The following performance graph compares the cumulative total stockholder return on Recovery Energy, Inc. common stock with the SPDR S &P 500 Stock Index and the Dow Jones US Oil and Gas Production index for the period from September 25, 2009 through December 31, 2011, assuming an initial investment of $100 and the reinvestment of all dividends, if any. This historic stock price performance is not necessarily indicative of future stock performance.



Recent Sales of Unregistered Securities

We have previously disclosed by way of quarterly reports on Form 10-Q and current reports on Form 8-K filed with the SEC all sales by us of our unregistered securities during 2011, except as follows:

In December 2011, we issued 66,330 shares of unregistered common stock to purchase oil and gas interests covering 884 net acres in Weld County, Colorado. Issuance of the shares described above was not registered under the Securities Act of 1933.

The issuance of these shares was exempt from registration, pursuant to Section 4(2) of the Securities Act of 1933. These securities qualified for exemption since the issuance of the securities by us did not involve a public offering and the purchasers are all accredited investors as defined in Regulation D under the Securities Act. The offering was not a "public offering" as defined in Section 4(2) due to the insubstantial number of persons involved in the sale, size of the offering, manner of the offering and number of securities offered. In addition, these shareholders have the necessary investment intent as required by Section 4(2) since each agreed to and received share certificates bearing a legend stating that such securities are restricted pursuant to Rule 144 of the 1933 Securities Act. This restriction ensures that these securities would not be immediately redistributed into the market and therefore not be part of a "public offering." Based on an analysis of the above factors, we have met the requirements to qualify for exemption under Section 4(2) of the Securities Act for this transaction.

Item 6. SELECTED FINANCIAL DATA

The table below contains selected consolidated financial data. The statement of operations, cash flow, balance sheet and other financial data for each year has been derived from our consolidated financial statements. You should read this information together with "Management's Discussion and Analysis of Financial Condition and Results of Operation" and our consolidated financial statements and the related notes included elsewhere in this report. Shares and per share data has been adjusted for the effects of a 1:4 reverse stock split completed in the 4th quarter of 2011. The Company owned no oil and gas properties prior to 2010, and had no significant operations prior to 2009.

	Years Ended December 31,		
	2011	2010	2009
REVENUES AND OTHER INCOME:			
Oil sales	7,148,110	9,504,737	-
Gas sales	547,190	68,075	-
Other	666,794	184,880	-
Total Revenues	8,362,094	9,757,692	-
COSTS AND EXPENSES:			
Production Costs	1,514,784	862,042	-
Production Taxes	838,714	1,056,244	-
General and administrative	10,544,347	15,530,248	1,057,306
Impairment of oil and natural gas properties	2,821,176	-	2,750,000
Depreciation depletion and amortization	4,347,117	5,036,648	-
Common stock and warrants issued in aborted property transactions	-	-	8,404,106
Restructuring and related consulting			17,700,000
Bad debt expense	-	400,000	-
Total costs and expenses	20,066,138	22,885,182	29,911,412
Income (loss) from continuing operations	(11,704,044)	(13,127,490)	(29,911,412)
Interest expense	(8,218,225)	(6,640,209)	31
Convertible notes derivative gain	3,821,792	-	-
Debt inducement expense	(2,800,000)	-	-
Other	71,253	28,666	-
Net loss	(18,829,225)	(19,739,033)	(29,911,381)
Net loss per common share:			
Basic and Diluted	$ (1.21)	$ (2.15)	$ (12.19)
Weighted average common shares outstanding:			
Basic and Diluted	15,543,758	9,167,803	2,453,921
Cash flow data:			
Cash flow provided by (used in) operations	(570,247)	3,758,694	(381,239)
Cash flow provided by /(used in) investing activities	(13,308,468)	(46,809,758)	639,639
Cash flow provided by/(used in) financing activities	11,057,693	48,471,408	(150,000)
Balance sheet data:			
Cash and cash equivalents	2,707,722	6,679,285	129,276
Property, plant and equipment, net of depletion and impairment	72,137,035	56,129,467	-
Total assets	81,287,860	68,121,929	895,026
Total liabilities	31,619,635	(23,865,327)	(328,754)
Common stock subject to redemption	-	(86,257)	(172,516)
Total shareholders' equity	49,668,225	44,170,344	393,756

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion should be read in conjunction with our financial statements included elsewhere in this annual report. This discussion contains forward-looking statements that involve risks and uncertainties. Our actual results could differ materially from those anticipated in these forward-looking statements as a result of various factors including those set forth under Item 1A "Risk Factors".

General

We are an independent oil and gas company engaged in the acquisition, drilling and production of oil and natural gas properties and prospects within the DJ Basin. Our business strategy is designed to create shareholder value by leveraging the knowledge, expertise and experience of our management team along with that of our operating partners.

We principally target low to medium risk projects that have the potential for multiple producing horizons, and offer repeatable success allowing for meaningful production and reserve growth. Our acquisition and exploration pursuits of oil and natural gas properties are principally located in Colorado, Nebraska, and Wyoming.

It is our belief that the exploration and production industry's most significant value creation occurs through the drilling of successful development wells and the enhancement of oil recovery in mature fields given appropriate economic conditions. We intend to acquire producing properties and develop properties based on our view of the pricing cycles of oil and natural gas and available exploration and development opportunities of proved, probable and possible reserves.

Results of Operations

2011 compared to 2010

The following table compares operating data for the fiscal year ended December 31, 2011 to December 31, 2010:

	2011	2010
REVENUES AND OTHER INCOME:		
Oil sales	7,148,110	9,504,737
Gas sales	547,190	68,075
Realized gains on commodity hedges	625,043	570,233
Other	41,751	(385,353)
	8,362,094	9,757,692
EXPENSES:		
Production Costs	1,514,784	862,042
Production Taxes	838,714	1,056,244
General and administrative	10,544,347	15,530,248
Impairment of oil and natural gas properties	2,821,176	-
Depreciation depletion and amortization	4,347,117	5,036,648
Bad debt expense	-	400,000
	20,066,138	22,885,182
Income (loss) from continuing operations	(11,704,044)	(13,127,490)
Interest expense	(8,218,225)	(6,640,209)
Other	71,253	28,666
Debt Inducement Expense	(2,800,000)	-
Conversion Note Derivative Gain	3,821,792	-
Net income	(18,829,224)	(19,739,033)

Total revenues in 2011 declined from $9.8 million in 2010 to $8.4 million in 2011 due primarily to a decrease in net oil production due to natural reservoir production declines. This reduction in oil sales was partially offset by an increase in net gas production, but also affected by changes in the average unit prices received by the Company for the sale of its oil and gas products. The following table shows the comparison of production volume and average prices:

	Year Ended December 31,	
	2011	**2010**
Oil Sales (net bbls)	81,443	133,709
Gas Sales (net mcf)	115,583	14,914
Average Oil Price	$ 87.77	$ 71.08
Average Gas Price	$ 4.73	$ 4.56
Average Price per BOE	76.41	74.47
Production Costs	15.19	6.33
Production Taxes	8.18	7.76
Depreciation and Amortization	42.25	36.98
Total Operating Costs	65.62	51.07
Gross Margin	10.79	23.40
Gross Margin %	14.12%	31.42%

As shown in the table, oil volumes declined 39%, gas volume increased by 675%, and prices for both oil and gas increased. The gas volume increase can be attributed to the production of one gas well that produced during the entirety of 2011, but only for part of 2010. The decline in oil volume is due almost entirely to natural production declines.

Other revenues in 2010 included an unrealized loss on commodity hedges of $399,000. Unrealized losses on commodity hedges in 2011 were nominal.

Production taxes in 2011 decreased by 22% in 2011 as a result in the overall decrease in oil and gas sales. Production costs increased by 77%. This increase is due primarily to an increase in the number of workovers, property improvements and other onsite work that was performed on our producing properties during the year.

Depletion expense declined in 2011 by 16% as a result of lower unit volumes of oil and gas sales, and a declining cost center, even though the cost per BOE increased by 14%.

An impairment expense of $2.8 million was recorded in 2011 as a result of capitalized costs exceeding the standardized measure of reserve values.

General and administrative expenses declined 32% in 2011 as compared to 2010. 2011 general and administrative expenses included non-cash stock compensation expense of $6.7 million compared to $13.1 million in 2010. Excluding these non-cash components, cash general and administrative expenses were $3.9 million in 2011 compared to $2.23 million in 2010. Cash general and administrative expenses in 2011 increased primarily as a result of an increase in payroll, and legal and third party fees related to transactions, as well as general increases in other general and administrative expense areas.

Interest expense increased by $1.6 million in 2011 as compared to 2010. 2011 interest includes non-cash loan costs amortization of $5.0 million, and cash interest expense of $3.2 million, compared to cash interest expense in 2010 of $2.7 million. Cash interest increased in 2011 primarily as a result of an increase in the average level of debt.

In 2011, we recorded inducement expense of $2.8 million related to an amendment of our convertible debentures that reduced the conversion price from $9.40 to $4.25 per share. The inducement related to a request to the holders of the convertible debentures to release certain collateral so that it could be sold. We also recorded derivative gains of $3.8 million related to the reduction of liability attributed to the conversion feature recorded as of the original transaction date in the first quarter of 2011, versus the liability related to this conversion feature as of the end of the year.

2010 compared to 2009

In general our revenues and expenses were significantly higher in 2010 when compared to inception through December 31, 2009 as during 2009 we were a development stage company with minimal activities. In January 2010, we acquired our first producing oil and gas assets and incurred interest expense with the associated debt utilized to acquire the property. Therefore, results are generally not comparable for the year ended December 31, 2010 to the period of inception through December 31, 2009. We have presented the results for each period below.

Revenue and other income:

For the twelve month period ended December 31, 2010, we had $9,504,737 in oil sales and $68,075 in natural gas sales, respectively.

Average daily net production for the twelve month period ended December 31, 2010 was 373 BOEPD.

Miscellaneous Income and Operating Fees

We earned net operating fees of $13,487 during the twelve months ended December 31, 2010. We realized a mark-to-market gain of $28,666 during the twelve months ended December 31, 2010 on a put agreement associated with 85,000 shares of stock placed in conjunction with our reverse merger in September 2009.

Price Risk Management Activities

We recorded a net loss on our derivative contracts that do not qualify for cash flow hedge accounting of $(398,840) for the year ended December 31, 2010. This amount represents an unrealized non-cash loss which represents a change in the fair value of our mark-to-market derivative instruments at December 31, 2010 as detailed in “Note 5 – Financial Instruments and Derivatives” and “Note 6 – Fair Value of Financial Instruments”. We realized a gain on our derivative contracts that do not qualify for cash flow hedge accounting $570,233 for the year ended December 31, 2010. This amount represents a realized cash gain from the settlement of our forward sale contracts for the quarter ended December 31, 2010 as detailed in “Note 5 – Financial Instruments and Derivatives” and “Note 6 – Fair Value of Financial Instruments”.

Oil and Gas Production Expenses, Depreciation, Depletion and Amortization

	Years ended December 31, 2010	2009 (1)
Net production		
Oil (Bbl)	133,709	-
Gas (Mcf)	14,914	-
MBOE	136,195	-
Average net daily production		
Oil (Bbl)	366	-
Gas (Mcf)	41	-
BOE	373	-
Average realized sales price, excluding the effects of hedging		
Oil (per Bbl)	$ 71.08	$ -
Gas (per Mcf)	$ 4.56	$ -
Per BOE	$ 70.29	$ -
Average realized sales price, including the effects of hedging		
Oil (per Bbl)	$ 75.27	$ -
Gas (per Mcf)	$ 4.56	$ -
Per BOE	$ 74.47	$ -
Production costs per BOE		
Lease operating expense (2)	$ 6.33	$ -
DD&A	$ 36.98	$ -
Production taxes	$ 7.76	$ -
Total operating costs	$ 51.07	$ -
Gross margin percentage	31%	$ -%

(1) Prior to January 2010, the Company did not own any oil and gas properties.
(2) Approximately $2.35/BOE of lease operating expense relates to surface, subsurface, road repairs and work-over activities.

General and Administrative Expenses

General and administrative expenses were $15,530,248 for the year ended December 31, 2010. Our general and administrative expenses twelve months ended December 31, 2010 included $1,464,990 in professional fees (financial advisors, attorneys, accountants, and reserve engineers) of which $372,393 were noncash, and $9,958,300 in non-cash compensation expense. We also incurred a non-cash expense of $54,500 in rental expense for our office lease for the year ending December 31, 2010 and a non-cash warrant modification expense of $2,953,450 for the year ended December 31, 2010. Total non-cash general and administrative expenditures for the year ended December 31, 2010 was approximately $13,300,000. This compares to approximately $1,057,306 in general and administrative expenditures from inception through December 31, 2009 which included non-cash expenditures of $690,000.

Depreciation Expense

Depreciation and amortization expense were $5,036,648 for the twelve months ended December 31, 2010.

Interest Expense

Total interest expense was $6,640,209 for the year ended December 31, 2010. The interest expense was comprised of $3,989,649 in non-cash amortization of expenses for the year ended December 31, 2010 related to warrants issued and overriding royalty interests assigned to our lender in conjunction with the closing of the three credit agreements and the extension of the credit agreements. We incurred $2,655,131 in cash interest expense for the year ended December 31, 2010. We, nor our predecessor business, did not incur interest expense from inception through December 31, 2009.

We incurred a net loss to common shareholders of $19,739,033 for the year ended December 31, 2010.

From inception through December 31, 2009

General and administrative expense for the period ended December 31, 2009 totaled $1,057,306, including non-cash expense $684,778 in compensation expense for outstanding restricted common stock grants issued to executive officers and board members.

Our expense for impairment of equipment held for sale was $2,750,000 for the period ended December 31, 2009.

Non-cash expenses related to the fair value of common stock issued in an attempted property transaction for the period ended December 31, 2009 totaled $5,075,000. Additional non-cash expenses for the period ended December 31, 2009 included $3,329,106 in fair value for warrants issued to third parties for a commitment to finance a property transaction which did not close, $200,000 related to 85,000 shares issued in conjunction with the merger and $17,500,000 related to 5 million shares acquired by our controlling shareholder group subsequent to the reverse merger.

Income for the period ended December 31, 2009 totaled $31 and was comprised of interest income.

We incurred a net loss to common shareholders of $29,911,381 for the period ended December 31, 2009.

Plan of Operations

Our plan of operations for the next twelve months is to identify and develop oil and natural gas prospects from our existing inventory of undeveloped acreage. In this regard, we have gradually added structure and staffing to our company as we become the operator of an increasing number of acquired properties. By acting as the operator, we have greater control over operating, drilling and developmental decisions, and would expect to generally better control our overall finding costs as we increase our exploration and development activities.

We anticipate the investment of substantial capital during the next few years to evaluate, assess and develop our existing inventory of developed and undeveloped oil and gas leases. The following table summarizes our inventory of developed and undeveloped oil and gas leases by expiration date:

Summary of Leases Held:	**Net Acres**
Held by production and continuous operations	19,126.40
Expired 2/2012	3,462.44
Expires 2012	805.89
Expires 2013	13,944.80
Expires 2014	25,530.36
Expires 2015	61,361.21
Expires 2016	5,957.95
Total Leased Acreage	130,189.04

Our existing producing properties currently extend the termination dates of leases that comprise 9,739 net acres indefinitely, until such time as commercial production ceases with respect to a well that is holding a respective lease tract. While these net acres are categorized as developed, many of these leases also have potential for future development in other zones known to be productive, such as the Niobrara. In addition, we are also currently conducting completion and/or evaluation procedures on two wells in progress. Operations that are being conducted on these two wells are extending the primary terms of leases that comprise approximately 9,387 net acres. Absent successful completions of one or both of these wells, the lease terms of some or all of these acres may expire. The Company's current investment in these leases is approximately $9.0 million.

Approximately 64% of our remaining inventory of undeveloped leases provide for extension of lease terms from two to five years, at the option of the Company, via payment of varying, but typically nominal, extension amounts.

The acquisition and development of properties and prospects and the pursuit of fresh opportunities require that we maintain access to adequate levels of capital. We will strive for an optimal balance between our property portfolio and our capital structuring that will allow for growth designed to build shareholder value and profitability. The decisions around the balancing of capital needs and property holdings will be a challenge to us as well as all companies in the entire energy industry during this time of continued disruption in the financial markets and an increasingly complex global economic picture. As a function of balancing properties and capital, we may decide to monetize certain properties to reduce debt or to allow us to acquire interests in new prospects or producing properties that may be better suited to the current economic and energy industry environment.

The business of oil and natural gas acquisition, exploration and development is capital intensive and the level of operations attainable by an oil and gas company is directly linked to and limited by the amount of available capital. Therefore, a principal part of our plan of operations is to raise the additional capital required to finance the exploration and development of our current oil and natural gas prospects and the acquisition of additional properties. As explained under "Financial Condition and Liquidity" below, based on our present working capital and current rate of cash flow from operations, we will need to raise additional capital to partially fund our overhead, and fund our exploration and development budget through, at least, December 31, 2012. We will seek additional capital through the sale of our securities and we will endeavor to obtain additional capital through debt and project financing. However, as described further below, under the terms of our $21 million in credit facilities, we are prohibited from incurring any additional debt from third parties without prior consent from our lender. Our ability to obtain additional capital through new debt instruments and project financing may be subject to the repayment of our $21 million credit facility.

We intend to use the services of independent consultants and contractors to perform various professional services, including land, legal, environmental, investor relations and tax services. We believe that by limiting our management and employee costs, we may be able to better control total costs and retain flexibility in terms of project management.

Financial Condition and Liquidity

Cash used in operating activities during the year ended December 31, 2011 was $.6 million, and cash used in investing activities exceeded cash provided by financing activities by approximately $2.2 million. This net cash use contributed to a substantial decrease in our net working capital as of December 31, 2011. Expenditures subsequent to December 31, 2011 have continued to exceed cash receipts, causing a further reduction of the Company's working capital position.

In the immediate term, the Company expects that additional capital will be required to fund its capital budget for 2012, to partially fund some of its ongoing overhead, and to provide additional capital to generally improve its working capital position. We anticipate that these capital requirements will be funded by a combination of capital raising activities, including the selling of additional debt and/or equity securities and the selling of certain assets. If we are not successful in obtaining sufficient cash sources to fund the aforementioned capital requirements, we may be required to curtail our expenditures, restructure our operations, sell assets on terms which may not be deemed favorable and/or curtail other aspects of our operations, including deferring portions of our 2012 capital budget.

Pursuant to our credit agreements with Hexagon, a substantial portion of our monthly net revenues derived from our producing properties is required to be used for debt and interest payments. In addition, our debt instruments contain provisions that, absent consent of the lenders, may restrict our ability to raise additional capital.

Since inception, we have raised approximately $72 million in cash generally through private placements of debt and equity securities. In December 2011, we sold certain undeveloped acreage for total proceeds of $4.5 million. During 2011, Hexagon agreed to temporarily suspend for five months the requirement to remit monthly net revenues of approximately $2,000,000 in the aggregate as payment on the Hexagon debt. In November 2011, Hexagon extended the maturity date of their notes to January 1, 2013, and also advanced an additional $309,000 to us. We repaid the $309,000 advance in February 2012. In March 2012, Hexagon extended the maturity date of their Notes to June 30, 2013, and in connection therewith we agreed to make minimum monthly note payments of $325,000, effective immediately. We will continue to pursue alternatives to shore up our working capital position and to provide funding for our planned 2012 expenditures.

On March 19, 2012, we entered into agreements with our existing convertible debenture holders to extend the amount of the convertible debenture debt by up to an additional $5.0 million. Proceeds resulting from the increase in the convertible debentures will be used to partially fund the 2012 Capital Budget. The initial closing related to these agreements will be in the amount of $1.5 million and is expected to occur prior to March 23, 2012. On or before September 15, 2012, convertible debenture holders may elect to purchase up to an additional $3.5 million in additional convertible debentures. All terms of the expansion convertible debentures are substantively identical to the existing convertible debentures.

2012 Capital Budget

Our anticipated 2012 capital expenditure budget is $10-15 million, which is allocated primarily to the drilling and completion of oil and gas wells in the DJ Basin in Wyoming, Nebraska and Colorado targeting the conventional Dakota 'D' sand and Muddy 'J' sand targets. In addition, approximately one-third of this budget may be directed toward additional development procedures on certain unconventional Niobrara shale properties. We estimate the completed cost for each conventional well to be between $800,000 and $900,000. Specific allocations of the 2012 budget directed at Niobrara shale properties have not been determined at this time.

Our 2012 capital expenditure budget is subject to various factors, including the availability of capital, market conditions, oilfield services and equipment availability, commodity prices and drilling results. While we continue to explore opportunities to expand our acreage position, our current budget is allocated to drilling and completing wells. Any leasehold acquisitions that we choose to pursue would require us to adjust our budget. Results from the wells identified in the capital budget may lead to additional adjustments to the capital budget as the cash flow from the wells could provide additional capital which we may use to increase our capital budget.

Other factors that could cause us to further increase our level of activity and adjust our capital expenditure budget include a reduction in service and material costs, the formation of joint ventures with other exploration and production companies, the divestiture of non-strategic assets, a further improvement in commodity prices or well performance that exceeds our forecasts, any of which could positively impact our operating cash flow. Factors that could cause us to reduce level of activity and adjust our capital budget include, but are not limited to, increases in service and materials costs, reductions in commodity prices or under-performance of wells relative to our forecasts, any of which could negatively impact our operating cash flow.

Our 2012 drilling program is designed to provide flexibility to accommodate both the timing of the securing of adequate capital, and to identify suitable well locations. We anticipate funding the 2012 capital program through a combination of the issuance of additional equity or debt securities, use of existing working capital and operating cash flows, and from cash provided by potential joint venture participants. We may choose to sell certain non-strategic assets in order to supplement the funding of our 2012 capital budget.

We cannot give assurances that our working capital on hand, our cash flow from operations or any available capital or borrowings, equity offerings or other financings, or sales of non-strategic assets will be sufficient to fund our anticipated capital expenditures. If our existing and potential sources of investment capital are not sufficient to undertake our planned 2012 capital expenditures, we may be required to reduce our 2012 drilling capital budget, curtail our expenditures and/or restructure our operations.

On March 19, 2012, we entered into agreements with our existing convertible debenture holders to extend the amount of the convertible debenture debt by up to an additional $5.0 million. Proceeds resulting from the increase in the convertible debentures will be used to partially fund the 2012 Capital Budget. The initial closing related to these agreements will be in the amount of $1.5 million and is expected to occur prior to March 23, 2012. On or before September 15, 2012, convertible debenture holders may elect to purchase up to an additional $3.5 million in additional convertible debentures. All terms of the expansion convertible debentures are substantively identical to the existing convertible debentures.

During the year ended December 31, 2011, our working capital decreased to $1.3 million compared to $4.4 million at December 31, 2010. This lower level of working capital is primarily of the result of cash used in opertions, and cash investing activities that exceeded cash provided by financing activities.

During the year ended December 31, 2011, net cash used in operating activities was $570,000. The primary changes in operating cash during the year ended December 31, 2010 were $18.8 million of net loss, adjusted for non-cash charges of $ 4.3 million of depreciation, depletion and amortization expenses and accretion expense, $6.5 million of stock-based compensation and stock paid for services, $4.4 million of amortization of deferred financing costs, $2.8 million of impairment expense, $2.8 million of debt inducement expense, and offset by $3.3 million in non-cash gains on derivatives.

During the year ended December 31, 2011, net cash used by investing activities was $13.3 million. The primary changes in investing cash during the year ended December 31, 2011 was $9.4 million in expenditures related to our acquisitions which consisted primarily of the unevaluated acreage, and $7.0 million in drilling capital expenditures, offset by $3.0 million in proceeds received from the sale of certain undeveloped acreage.

During the year ended December 31, 2011, net cash provided by financing activities was $11.0 million. The primary changes in financing cash during the year ended December 31, 2011 were $8.0 million related to the issuance of convertible debt, $2.1 million derived from the issuance of common stock, and $.9 million in other changes in debt.

Our primary term debt of $21 million is currently due on June 30, 2013. We will very likely need to replace or refinance this debt prior to its due date. While we believe we have sufficient liquidity and other sources of capital available to us that will allow us to conduct our current operations for the next 12 months, we will need to find additional sources of capital to fund our drilling budget and, if necessary, to replace our existing debt facility. We will seek to obtain this additional capital through a combination of the issuance of additional equity or debt securities, use of existing working capital and operating cash flows, and from cash provided by potential joint venture participants. We may also choose to sell certain non-strategic assets in order to supplement the funding of our 2012 capital budget.

Currently, we have no agreements or understandings with any third parties at this time for additional working capital. Further, under the terms of our credit agreements, we are prohibited from incurring any additional debt from third parties without prior consent from our lender. Our ability to obtain additional working capital through bank lines of credit and project financing may be subject to the repayment of the approximately $21 million debt related to our primary credit facility. Consequently, there can be no assurance we will be able to obtain continued access to capital as and when needed or, if so, that the terms of any available financing will be subject to commercially reasonable terms. If we are unable to access additional capital in significant amounts as needed, we may not be able to develop our current prospects and properties, may have to forfeit our interest in certain prospects and may not otherwise be able to develop our business. In such an event, our stock price will be materially adversely affected.

Obligations and Commitments

We have the following contractual obligations and commitments as of December 31, 2011 (in thousands):

	Payments due by period				
Contractual obligations	**Total**	**Within 1 year**	**2-3 years**	**4-5 years**	**More than 5 years**
Secured debt	$ 21,280,637	$ 1,150,967	$ 20,129,670	$ —	$ —
Interest on secured debt	4,725,000	3,150,000	1,575,000	—	—
Convertible debentures	8,400,000		8,400,000	—	—
Interest on convertible debentures	1,428,000	672,000	756,000		
Operating leases	72,000	72,000	—	—	—
Total contractual cash obligations (1)	$ 35,905,637	$ 5,044,967	$ 30,860,670	$ —	$ —

(1) We could be liable for liquidated damages under registration rights agreements covering approximately 3.2 million shares of our common stock if we fail to maintain the effectiveness of a prior registration statement as required in the agreements. In such case, we would be required to pay monthly liquidated damages of up to $228,050. The maximum aggregate liquidated damages are capped at $1,368,300

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

Critical Accounting Policies and Estimates

The preparation of our consolidated financial statements in conformity with generally accepted accounting principles in the United States, or GAAP, requires our management to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities at the date of our financial statements and the reported amounts of revenues and expenses during the reporting period. The following is a summary of the significant accounting policies and related estimates that affect our financial disclosures.

Critical accounting policies are defined as those significant accounting policies that are most critical to an understanding of a company's financial condition and results of operation. We consider an accounting estimate or judgment to be critical if (i) it requires assumptions to be made that were uncertain at the time the estimate was made, and (ii) changes in the estimate or different estimates that could have been selected could have a material impact on our results of operations or financial condition.

Use of Estimates

The financial statements included herein were prepared from the records of Recovery in accordance with generally accepted accounting principles in the United States, or GAAP, and reflect all normal recurring adjustments which are, in the opinion of management, necessary to provide a fair statement of the results of operations and financial position for the interim periods. The preparation of the financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of oil and gas reserves, assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. We evaluate our estimates on an on-going basis and base our estimates on historical experience and on various other assumptions we believe to be reasonable under the circumstances. Although actual results may differ from these estimates under different assumptions or conditions, we believe that our estimates are reasonable. Our most significant financial estimates are associated with our estimated proved oil and gas reserves as well as valuation of common stock used in various issuances of common stock, options and warrants and estimated fair value of the asset held for sale.

Oil and Natural Gas Reserves

We follow the full cost method of accounting. All of our oil and gas properties are located within the United States, and therefore all costs related to the acquisition and development of oil and gas properties are capitalized into a single cost center referred to as a full cost pool. Depletion of exploration and development costs and depreciation of production equipment is computed using the units-of-production method based upon estimated proved oil and gas reserves. Under the full cost method of accounting, capitalized oil and gas property costs less accumulated depletion and net of deferred income taxes may not exceed an amount equal to the present value, discounted at 10%, of estimated future net revenues from proved oil and gas reserves less the future cash outflows associated with the asset retirement obligations that have been accrued on the balance sheet plus the cost, or estimated fair value if lower, of unproved properties. Should capitalized costs exceed this ceiling, impairment would be recognized. Under the SEC rules, we prepared our oil and gas reserve estimates as of December 31, 2011, using the average, first-day-of-the-month price during the 12-month period ending December 31, 2011.

Estimating accumulations of gas and oil is complex and is not exact because of the numerous uncertainties inherent in the process. The process relies on interpretations of available geological, geophysical, engineering and production data. The extent, quality and reliability of this technical data can vary. The process also requires certain economic assumptions, some of which are mandated by the SEC, such as gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The accuracy of a reserve estimate is a function of the quality and quantity of available data; the interpretation of that data; the accuracy of various mandated economic assumptions; and the judgment of the persons preparing the estimate.

We believe estimated reserve quantities and the related estimates of future net cash flows are the most important estimates made by an exploration and production company such as ours because they affect the perceived value of our company, are used in comparative financial analysis ratios, and are used as the basis for the most significant accounting estimates in our financial statements, including the quarterly calculation of depletion, depreciation and impairment of our proved oil and natural gas properties. Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. We determine anticipated future cash inflows and future production and development costs by applying benchmark prices and costs, including transportation, quality and basis differentials, in effect at the end of each quarter to the estimated quantities of oil and natural gas remaining to be produced as of the end of that quarter. We reduce expected cash flows to present value using a discount rate that depends upon the purpose for which the reserve estimates will be used. For example, the standardized measure calculation required by ASC Topic 932, Extractive Activities —Oil and Gas, requires us to apply a 10% discount rate. Although reserve estimates are inherently imprecise, and estimates of new discoveries and undeveloped locations are more imprecise than those of established proved producing oil and natural gas properties, we make considerable effort to estimate our reserves, including through the use of independent reserves engineering consultants. We expect that quarterly reserve estimates will change in the future as additional information becomes available or as oil and natural gas prices and operating and capital costs change. We evaluate and estimate our oil and natural gas reserves as of December 31 of each year and quarterly throughout the year. For purposes of depletion, depreciation, and impairment, we adjust reserve quantities at all quarterly periods for the estimated impact of acquisitions and dispositions. Changes in depletion, depreciation or impairment calculations caused by changes in reserve quantities or net cash flows are recorded in the period in which the reserves or net cash flow estimate changes.

Oil and Natural Gas Properties—Full Cost Method of Accounting

We use the full cost method of accounting whereby all costs related to the acquisition and development of oil and natural gas properties are capitalized into a single cost center referred to as a full cost pool. These costs include land acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling and overhead charges directly related to acquisition and exploration activities.

Capitalized costs, together with the costs of production equipment, are depleted and amortized on the unit-of-production method based on the estimated gross proved reserves as determined by independent petroleum engineers. For this purpose, we convert our petroleum products and reserves to a common unit of measure.

Costs of acquiring and evaluating unproved properties are initially excluded from depletion calculations. These unevaluated properties are assessed quarterly to ascertain whether impairment has occurred. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to the full cost pool and becomes subject to depletion calculations.

Proceeds from the sale of oil and natural gas properties are applied against capitalized costs, with no gain or loss recognized, unless the sale would alter the rate of depletion by more than 25%. Royalties paid, net of any tax credits received, are netted against oil and natural gas sales.

In applying the full cost method, we perform a ceiling test on properties that restricts the capitalized costs, less accumulated depletion, from exceeding an amount equal to the estimated undiscounted value of future net revenues from proved oil and natural gas reserves, as determined by independent petroleum engineers. The estimated future revenues are based on sales prices achievable under existing contracts and posted average reference prices in effect at the end of the applicable period, and current costs, and after deducting estimated future general and administrative expenses, production related expenses, financing costs, future site restoration costs and income taxes. Under the full cost method of accounting, capitalized oil and natural gas property costs, less accumulated depletion and net of deferred income taxes, may not exceed an amount equal to the present value, discounted at 10%, of estimated future net revenues from proved oil and natural gas reserves, plus the cost, or estimated fair value if lower, of unproved properties. Should capitalized costs exceed this ceiling, we would recognize impairment.

Revenue Recognition

The Company derives revenue primarily from the sale of produced natural gas and crude oil. The Company reports revenue as the gross amount received before taking into account production taxes and transportation costs, which are reported as separate expenses and are included in oil and gas production expense in the accompanying consolidated statements of operations. Revenue is recorded in the month the Company's production is delivered to the purchaser, but payment is generally received between 30 and 90 days after the date of production. No revenue is recognized unless it is determined that title to the product has transferred to the purchaser. At the end of each month, the Company estimates the amount of production delivered to the purchaser and the price the Company will receive. The Company uses its knowledge of its properties, their historical performance, NYMEX and local spot market prices, quality and transportation differentials, and other factors as the basis for these estimates.

Share Based Compensation

The Company accounts for share-based compensation by estimating the fair value of share-based payment awards made to employees and directors, including restricted stock grants, on the date of grant. The value of the portion of the award that is ultimately expected to vest is recognized as an expense ratably over the requisite service periods.

Derivative Instruments

During 2011, the Company entered into swaps to reduce the effect of price changes on a portion of our future oil production. We reflect the fair market value of our derivative instruments on our balance sheet. Our estimates of fair value are determined by obtaining independent market quotes as well as utilizing a valuation model that is based upon underlying forward curve data and risk free interest rates. Changes in commodity prices will result in substantially similar changes in the fair value of our commodity derivative agreements. We do not apply hedge accounting to any of our derivative contracts, therefore we recognize mark-to-market gains and losses in earnings currently.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risk represents the risk of loss that may impact our financial position, results of operations, or cash flows due to adverse changes in financial market prices, including interest rate risk, foreign currency exchange rate risk, commodity price risk, and other relevant market or price risks.

Commodities Price Risk. Our financial condition, results of operations and capital resources are dependent upon the prevailing market prices of oil and natural gas. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors that are beyond our control. Factors influencing oil and natural gas prices include the level of global demand for crude oil, the foreign supply of oil and natural gas, the establishment of and compliance with production quotas by oil exporting countries, weather conditions which determine the demand for natural gas, the price and availability of alternative fuels and overall economic conditions. It is impossible to predict future oil and natural gas prices with any degree of certainty. Sustained weakness in oil and natural gas prices may adversely affect our financial condition and results of operations, and may also reduce the amount of oil and natural gas reserves that we can produce economically. Any reduction in our oil and natural gas reserves, including reductions due to price fluctuations, can have an adverse effect on our ability to obtain capital for our development activities.

In order to protect the Company from uncertainty associated with oil and natural gas prices we entered into the following:

On December 21, 2011, we entered into a Commodity Fixed Price Swap contract that covers approximately 40% of our forecasted 2012 oil production. This contract covers 100 bopd throughout 2012, or a total of 36,600 barrels, and establishes a fixed sales price per barrel of $96.25. At the end of each month in 2012, the fixed price is compared to a floating price equal to the average of settlement prices of the Nymex Prompt month WTI crude oil contract. If the fixed price is less than the floating price, then the Company will make an immediate payment to the swap counterparty equal to the difference in the fixed and floating prices multiplied by the monthly oil volume (3,000 barrels in a 30 day month). Alternatively, if the fixed price is more than the floating price, then we will receive a payment from the swap counterparty equal to the difference between the fixed and floating prices multiplied by the monthly volume.

As of December 31, 2011, the estimated forward floating price was approximately $2 per barrel higher than the fixed price. As a result, we recorded an unrealized loss accrual related to this Swap contract of approximately $76,000.

We may, from time to time, enter into other similar agreements in order to hedge oil prices from future substantial price swings.

Interest Rate Risk. We have minimal interest rate risk as all of our debt currently provides for fixed interest rates. However, we may enter into future transactions that could result in higher interest rates, or in floating or adjustable interest rates that could expose the Company to additional interest rate risks.

Foreign Currency Risk. We do not currently have any substantial exposure to foreign currency risk.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Our financial statements appear immediately after the signature page of this report. See "Index to Financial Statements" included in this report.

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

Item 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures. We conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the “Exchange Act ”)) as of December 31, 2011. This evaluation was conducted under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of December 31, 2011, our disclosure controls and procedures were effective to ensure that information required to be disclosed by us in reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the rules and forms of the SEC, and that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Management’s Annual Report on Internal Control over Financial Reporting. Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of financial statements for external reporting purposes in accordance with generally accepted accounting principles. Internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of assets of the company, (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements.

Management conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2011, based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that our internal control over financial reporting was ineffective as of December 31, 2011, and noted the following material weaknesses:

- Insufficient independent internal review and approval of critical accounting schedules used in the preparation of financial statements.
- The financial statement close process did not permit timely preparation of necessary financial information and there is inadequate documentation of internal controls for some assertions in certain significant accounts.
- Lack of effective controls over general ledger processing, spreadsheets and data back-up.

Management reviewed the results of its assessment with our Audit Committee. The effectiveness of our internal control over financial reporting as of December 31, 2011 has been audited by Hein & Associates LLP, an independent registered public accounting firm, as stated in its report which is included in this item.

Changes in Internal Control over Financial Reporting.

There have been changes in our internal control over financial reporting during the three months ended December 31, 2011 that have improved our internal control over financial reporting. As described in Item 4T, "Controls and Procedures" in our quarterly reports on Form 10-Q dated June 30, 2011 and September 30, 2011, we identified material weaknesses in our internal controls over financial reporting with regard to having sufficient control over the timely review of contracts with financial implications and the review of critical accounting schedules.

During the 4th quarter of 2011, a plan was introduced to address the material weaknesses described in the quarterly reports. Specifically, with respect to review of contracts, management implemented financial procedures designed to improve communication within the company, its auditors and legal counsel to identify material contracts and analyze them for disclosure and accounting implications. Additionally, management began implementing many entity-specific controls designed to devote resources to the improvement of our internal control over financial reporting and in particular, provide an overall company-wide financial review to ensure all critical accounting schedules are properly and timely prepared and reviewed. Management also implemented certain financial procedures designed to improve the documentation of internal controls and closing procedures. This plan was not completed as of December 31, 2011; however, management is continuing with the implementation of this plan with a view toward completion of such plan in 2012.

Also, during the three months ended December 31, 2011, management began the process of implementing a new accounting system (software) to improve and solidify our procedures and to help mitigate the risk of material misstatements within the financial reporting process. The implementation was not completed as of December 31, 2011. Management believes that full implementation in 2012 of the new accounting system, along with certain other changes to its control procedures, will likely address the material weaknesses that existed as of December 31, 2011.

Limitations in Controls and Procedures

Our controls and procedures are designed at a reasonable assurance level. In designing and evaluating our controls and procedures, management recognizes that, because of inherent limitations, any system of controls and procedures, no matter how well designed and operated, can provide only reasonable, not absolute, assurance of achieving the desired objectives of the control system. In addition, the design of a control system must reflect the fact that there are resource constraints, and management must apply its judgment in evaluating the benefits of possible controls relative to their costs. Further, no evaluation of controls and procedures can provide absolute assurance that all errors, control issues and instances of fraud will be prevented or detected. Controls can also be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls and procedures is also based in part on certain assumptions regarding the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders

Recovery Energy, Inc.

We have audited Recovery Energy, Inc. and subsidiaries' (the "Company") internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Recovery Energy, Inc.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying *Management's Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that *(a)* pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; *(b)* provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and *(c)* provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the company's annual or interim financial statements will not be prevented or detected on a timely basis. The following material weaknesses have been identified and included in management's assessment:

- Insufficient independent internal review and approval of critical accounting schedules used in the preparation of financial statements.
- The financial statement close process did not permit timely preparation of necessary financial information and there is inadequate documentation of internal controls for some assertions in certain significant accounts.
- Lack of effective controls over general ledger processing, spreadsheets and data back-up.

These material weaknesses were considered in determining the nature, timing, and extent of audit tests applied in our audit of the 2011 financial statements, and this report does not affect our report dated March 29, 2012 on those financial statements.

In our opinion, because of the effect of the material weaknesses described above on the achievement of the objectives of the control criteria, Recovery Energy, Inc. has not maintained effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of Recovery Energy, Inc. and our report dated March 29, 2012 expressed an unqualified opinion.

Hein & Associates LLP
Denver, Colorado
March 29, 2012

Item 9B. OTHER INFORMATION

None.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information relating to this item will be included in an amendment to this report or in the proxy statement for our 2012 annual shareholders meeting and is incorporated by reference in this report.

Item 11. EXECUTIVE COMPENSATION

Information relating to this item will be included in an amendment to this report or in the proxy statement for our 2012 annual shareholders meeting and is incorporated by reference in this report.

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information relating to this item will be included in an amendment to this report or in the proxy statement for our 2012 annual shareholders meeting and is incorporated by reference in this report.

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information relating to this item will be included in an amendment to this report or in the proxy statement for our 2012 annual shareholders meeting and is incorporated by reference in this report.

Item 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information relating to this item will be included in an amendment to this report or in the proxy statement for our 2012 annual shareholders meeting and is incorporated by reference in this report.

PART IV

Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

INDEX TO FINANCIAL STATEMENTS

a)

b) Financial statement schedules

Not applicable.

c) Exhibits

The following exhibits are either filed herewith or incorporated herein by reference:

2.1	Membership Unit Purchase Agreement by and among Recovery Energy, Lanny M. Roof, Judith Lee and Michael Hlvasa dated as of September 21, 2009 (incorporated herein by reference to Exhibit 2.1 from our current report filed on form 8-K filed on September 22, 2009).
3.1	Articles of Incorporation (incorporated herein by reference to Exhibit 3.1 to Company's form S-1 filed on July 28, 2008).
3.2	Amended and Restated Bylaws (incorporated herein by reference to Exhibit 3.2 to Company's periodic report on form 8-K filed on June 18, 2010).
4.1	Warrant to Purchase Common Stock dated December 11, 2009 (incorporated by reference to Exhibit 4.2 to Company's current report filed on form 8-K filed on December 17, 2009).
10.1	Cancellation agreements, dated September 21, 2009 between Universal Holdings, Inc. and two former shareholders (incorporated herein by reference to Exhibit 10.1 to the Company's annual report on form 10-K for the year ended December 31, 2010).
10.2	Lock-Up Agreement with Tryon Capital Ventures, LLC as of September 21, 2009 (incorporated herein by reference to Exhibit 10.2 to Company's current report filed on form 8-K filed on September 22, 2009).
10.3	Equipment Purchase Agreement, dated May 31, 2009 (incorporated herein by reference to Exhibit 10.3 to Company's current report filed on form 8-K filed on September 22, 2009).
10.4	Agreement with New Century Capital Partners dated as of November 16, 2009 (incorporated herein by reference to Exhibit 10.4 to Company's current report filed on form 8-K filed on November 23, 2009).
10.5	Purchase and Sale Agreement with Edward Mike Davis, L.L.C. for purchase of 100% interest in Church field dated as of October 1, 2009 (incorporated herein by reference to Exhibit 10.5 to Company's current report filed on form 8-K filed on November 13, 2009).
10.6	Purchase and Sale Agreement with Duane M. Freund Irrevocable Trust 2 for purchase of 50% interest in Church field dated as of October 1, 2009 (incorporated herein by reference to Exhibit 10.6 to Company's current report filed on form 8-K filed on November 13, 2009).
10.7	Purchase and Sale Agreement with Roger A. Parker for Church field dated effective as of October 1, 2009 (incorporated herein by reference to Exhibit 10.11 to Company's current report filed on form 8-K filed on January 21, 2010).
10.8	Purchase and Sale Agreement with Edward Mike Davis, L.L.C. for Wilke Field dated effective as of January 1, 2010 (incorporated herein by reference to Exhibit 10.8 to Company's annual report on form 10-K for the year ended December 31, 2009).
10.9	Credit Agreement with Hexagon Investments, LLC dated effective as of January 29, 2010 (incorporated herein by reference to Exhibit 10.12 to Company's current report filed on form 8-K filed on March 4, 2010).
10.10	Promissory Note for financing with Hexagon Investments, LLC dated as of January 29, 2010 (incorporated herein by reference to Exhibit 10.13 to Company's current report filed on form 8-K filed on March 4, 2010).
10.11	Nebraska Mortgage to Hexagon Investments, LLC dated as of January 29, 2010 (incorporated herein by reference to Exhibit 10.14 to Company's current report filed on form 8-K filed on March 4, 2010).
10.12	Colorado Mortgage to Hexagon Investments, LLC dated as of January 29, 2010 (incorporated herein by reference to Exhibit 10.15 to Company's current report filed on form 8-K filed on March 4, 2010).

10.13	Purchase and Sale Agreement with Edward Mike Davis, L.L.C. dated effective as of April 1, 2010 (incorporated herein by reference to Exhibit 10.16 to Company's current report filed on form 8-K filed on March 25, 2010).
10.14	Credit Agreement with Hexagon Investments, LLC dated effective as of March 25, 2010 (incorporated herein by reference to Exhibit 10.17 to Company's current report filed on form 8-K filed on March 25, 2010).
10.15	Promissory Note for financing with Hexagon Investments, LLC dated as of March 25, 2010 (incorporated herein by reference to Exhibit 10.18 to Company's current report filed on form 8-K filed on March 25, 2010).
10.16	Nebraska Mortgage to Hexagon Investments, LLC dated as of March 25, 2010 (incorporated herein by reference to Exhibit 10.19 to Company's current report filed on form 8-K filed on March 25, 2010).
10.17	Wyoming Mortgage to Hexagon Investments, LLC dated as of March 25, 2010 (incorporated herein by reference to Exhibit 10.20 to Company's current report filed on form 8-K filed on March 25, 2010).
10.18	Purchase and Sale Agreement with Edward Mike Davis, L.L.C. for purchase of oil and gas properties dated as of April 1, 2010 (incorporated herein by reference to Exhibit 10.1 to the Company's current report filed on form 8-K filed on April 20, 2010).
10.19	Credit Agreement with Hexagon Investments, LLC dated as of April 14, 2010 (incorporated herein by reference to Exhibit 10.2 to the Company's current report filed on form 8-K filed on April 20, 2010).
10.20	Promissory Note with Hexagon Investments, LLC dated April 14, 2010 (incorporated herein by reference to Exhibit 10.3 to the Company's current report filed on form 8-K filed on April 20, 2010).
10.21	Warrant to Purchase Common Stock by Hexagon Investments, LLC dated April 14, 2010 (incorporated herein by reference to Exhibit 10.4 to the Company's current report filed on form 8-K filed on April 20, 2010).
10.22	Wyoming Mortgage to Hexagon Investments, LLC dated April 14, 2010 (incorporated herein by reference to Exhibit 10.5 to the Company's current report filed on form 8-K filed on April 20, 2010).
10.23	Securities Purchase Agreement dated as of April 26, 2020 (incorporated herein by reference to Exhibit 10.1 to the Company's current report filed on form 8-K filed on April 30, 2010).
10.24	Agreement with C.K. Cooper dated April 8, 2010 (incorporated herein by reference to Exhibit 10.1 to the Company's current report filed on form 8-K filed on May 4, 2010).
10.25	Purchase Agreement dated May 6, 2010 (incorporated herein by reference to Exhibit 10.1 to the Company's current report filed on form 8-K filed on May 12, 2010).
10.26	Promissory Note dated May 6, 2010 (incorporated herein by reference to Exhibit 10.2 to the Company's current report filed on form 8-K filed on May 12, 2010).
10.27	Security Agreement dated May 6, 2010 (incorporated herein by reference to Exhibit 10.3 to the Company's current report filed on form 8-K filed on May 12, 2010).
10.28	Purchase Agreement with Edward Mike Davis, L.L.C. and Spottie, Inc. dated May 15, 2010 (incorporated herein by reference to Exhibit 10.1 to the Company's current report filed on form 8-K filed on May 20, 2010).
10.29	Employment Agreement with Roger A. Parker (previously filed with annual report on form 10-K filed on March 21, 2012).
10.30	Employment Agreement with Jeffrey A. Beunier (incorporated herein by reference to Exhibit 10.2 to the Company's current report filed on form 8-K filed on December 23, 2010).

10.31	Director Appointment Agreement with James Miller (incorporated herein by reference to Exhibit 10.3 to the Company's current report filed on form 8-K filed on May 20, 2010).
10.32	Form of Warrant Issued in Private Placement (incorporated herein by reference to Exhibit 4.1 to the Company's current report filed on form 8-K filed on June 4, 2010).
10.33	Warrant issued to Hexagon Investments, LLC (incorporated herein by reference to Exhibit 4.2 to the Company's current report filed on form 8-K filed on June 4, 2010).
10.34	Form of Securities Purchase Agreement (incorporated herein by reference to Exhibit 10.1 to the Company's current report filed on form 8-K filed on June 4, 2010).
10.35	Form of Registration Rights Agreement (incorporated herein by reference to Exhibit 10.2 to the Company's current report filed on form 8-K.
10.36	Form of Lockup Agreement (incorporated herein by reference to Exhibit 10.3 to the Company's current report filed on form 8-K filed on June 4, 2010).
10.37	Letter Agreement with Hexagon Investments, LLC (incorporated herein by reference to Exhibit 10.4 to the Company's current report filed on form 8-K filed on June 4, 2010).
10.38	Independent Director Appointment Agreement with Timothy N. Poster (incorporated herein by reference to Exhibit 10.1 to the Company's current report filed on form 8-K filed on June 7, 2010).
10.39	Independent Director Appointment Agreement with Conway J. Schatz (incorporated herein by reference to Exhibit 10.2 to the Company's current report filed on form 8-K filed on June 7, 2010).
10.40	Consulting Agreement with Market Development Consulting Group, Inc. (incorporated herein by reference to Exhibit 10.1 to the Company's current report filed on form 8-K filed on June 18, 2010).
10.41	Five Year Warrant to Market Development Consulting Group, Inc. (incorporated herein by reference to Exhibit 10.2 to the Company's current report filed on form 8-K filed on June 18, 2010).
10.42	Three Year Warrant to Market Development Consulting Group, Inc. (incorporated herein by reference to Exhibit 10.3 to the Company's current report filed on form 8-K filed on June 18, 2010).
10.43	Warrant to Globe Media (incorporated herein by reference to Exhibit 10.4 to the Company's current report filed on form 8-K filed on June 18, 2010).
10.44	Registration Rights Agreement with Hexagon Investments, Inc. (incorporated herein by reference to Exhibit 10.5 to the Company's current report filed on form 8-K filed on June 18, 2010).
10.45	Stockholders Agreement with Hexagon Investments Incorporated (incorporated herein by reference to Exhibit 10.1 to the Company's current report filed on form 8-K filed on June 29, 2010).
10.46	Form of $2.20 Warrant Issued to Persons Exercising $1.50 Warrants (incorporated herein by reference to Exhibit 10.1 to the Company's current report on form 8-K filed on October 8, 2010).
10.47	Purchase Agreement with Edward Mike Davis, L.L.C. and Spottie, Inc. dated November 19, 2010 (incorporated herein by reference to Exhibit 10.1 to the Company's current report on form 8-K filed on November 26, 2010).
10.48	Put Option Agreement with Grandhaven Energy, LLC dated November 19, 2010 (incorporated herein by reference to Exhibit 10.2 to the Company's current report on form 8-K filed on November 26, 2010).

10.49	Warrant Issued to Hexagon Investments, LLC on January 1, 2011 (incorporated herein by reference to Exhibit 10.1 to the Company's current report on form 8-K filed on January 4, 2011).
10.50	Amendments to Hexagon Investments, LLC Promissory Notes (incorporated herein by reference to Exhibit 10.2 to the Company's current report on form 8-K filed on January 4, 2011).
10.51	Form of Convertible Debenture Securities Purchase Agreement dated February 2, 2011 (incorporated herein by reference to Exhibit 10.1 to the Company's current report on form 8-K filed on February 3, 2011).
10.52	Form of Convertible Debenture (incorporated herein by reference to Exhibit 10.2 to the Company's current report on form 8-K filed on February 3, 2011).
10.53	Purchase Agreement with Wapiti Oil & Gas, L.L.C. (incorporated herein by reference to Exhibit 10.1 to the Company's current report on form 8-K filed on February 24, 2011).
10.54	Termination Agreement dated as of December 15, 2009 with Edward Mike Davis, L.L.C. (incorporated herein by reference to Exhibit 10.54 to the Company's annual report on form 10-K for the year ended December 31, 2010).
10.55	Amendments to three Credit Agreements with Hexagon, LLC, dated March 15, 2012 (previously filed with annual report on form 10-K filed on March 21, 2012).
10.56	Second Amendment to 8% Senior Secured Convertible Debentures dated March 19, 2012 (previously filed with annual report on form 10-K filed on March 21, 2012).
10.57	Securities Purchase Agreement for additional 8% Senior Secured Convertible Debentures dated March 19, 2012 (previously filed with annual report on form 10-K filed on March 21, 2012).
10.58	Form of 8% Senior Secured Convertible Debentures dated March 19, 2012 (previously filed with annual report on form 10-K filed on March 21, 2012).
14.1	Code of Ethics (incorporated herein by reference to Exhibit 14.1 to the Company's annual report on form 10-K for the year ended December 31, 2009).
16.1	Letter from Jewett, Schwartz, Wolfe & Associates to the U.S. Securities and Exchange Commission dated January 19, 2010 (incorporated herein by reference to Exhibit 16.1 to the Company's periodic report on form 8-K dated January 21, 2010).
21.1	List of subsidiaries of the registrant (incorporated herein by reference to Exhibit 21.1 to the Company's registration statement on Form S-1 (333-164291).
23.1	Consent of Hein & Associates, LLP (included in their report on page F-1)
23.2	Consent of RE Davis (previously filed with annual report on form 10-K filed on March 21, 2012).
31.1	Certifications Pursuant to Section 302 of Sarbanes Oxley Act of 2002 (previously filed with annual report on form 10-K filed on March 21, 2012).
31.2	Certifications Pursuant to Section 302 of Sarbanes Oxley Act of 2002 (previously filed with annual report on form 10-K filed on March 21, 2012).
32.1	Certifications Pursuant to Section 906 of Sarbanes Oxley Act of 2002 (previously filed with annual report on form 10-K filed on March 21, 2012)
32.2	Certifications Pursuant to Section 906 of Sarbanes Oxley Act of 2002 (previously filed with annual report on form 10-K filed on March 21, 2012).
99.1	Report of RE Davis (previously filed with annual report on form 10-K filed on March 21, 2012).

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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.

RECOVERY ENERGY INC

Date: March 29 , 2012

By: /s/ Roger A Parker
Roger A. Parker
President, Chief Executive Officer and Chairman of the Board of Directors
(Authorized Signatory)

Pursuant to the requirements of the Securities and Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and the capacities and on the dates indicated.

Signature	Title	Date
/s/ Roger A. Parker Roger A Parker	President, Chief Executive Officer and Chairman of the Board of Directors	March 29 , 2012
/s/ A. Bradley Gabbard A. Bradley Gabbard	Chief Financial and Accounting Officer	March 29 , 2012
/s/ Eric Ulwelling Eric Ulwelling	Principal Accounting Officer	March 29 , 2012
/s/ Tim Poster Tim Poster	Director	March 29 , 2012
/s/ W. Phillip Marcum W. Phillip Marcum	Director	March 29 , 2012

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders

Recovery Energy, Inc.

We have audited the accompanying consolidated balance sheets of Recovery Energy, Inc. and subsidiaries (the “Company”) as of December 31, 2011 and 2010, and the related consolidated statements of operations, shareholders’ equity, and cash flows for the years ended December 31, 2011 and 2010 and for the period from March 6, 2009 (inception) through December 31, 2009. These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Recovery Energy, Inc. and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for the years ended December 31, 2011 and 2010, and for the period from March 6, 2009 (inception) through December 31, 2009, in conformity with U.S. generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Recovery Energy, Inc. and subsidiaries’ internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Our report dated March 29, 2012 expressed an opinion that Recovery Energy, Inc. had not maintained effective internal control over financial reporting as of December 31, 2011.

Hein & Associates LLP
Denver, Colorado
March 29, 2012

RECOVERY ENERGY, INC.
CONSOLIDATED BALANCE SHEETS

	December 31, 2011	December 31, 2010
ASSETS		
Current assets:		
Cash	$ 2,707,722	$ 5,528,744
Restricted cash	932,165	1,150,541
Accounts receivable	2,227,466	857,554
Prepaid assets	75,376	27,772
Total current assets	5,942,729	7,564,611
Oil and gas properties (full cost method), at cost:		
Unevaluated properties	45,697,481	33,605,594
Evaluated properties	32,113,143	26,307,975
Wells in progress	6,425,509	1,219,397
Total oil and gas properties, at cost	84,236,133	61,132,966
Less accumulated depreciation, depletion and amortization	(12,099,098)	(5,003,499)
Net oil and gas properties, at cost	72,137,035	56,129,467
Other assets:		
Office equipment, net	106,286	51,129
Prepaid advisory fees	574,160	979,449
Deferred financing costs	2,341,595	3,211,566
Restricted cash and deposits	186,055	185,707
Total other assets	3,208,096	4,427,851
Total Assets	$ 81,287,860	$ 68,121,929

The accompanying notes are an integral part of these financial statements.

RECOVERY ENERGY, INC.
CONSOLIDATED BALANCE SHEETS

	December 31, 2011	December 31, 2010
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 2,050,768	$ 968,295
Commodity price derivative liability	75,609	398,840
Related party payable	16,475	11,638
Accrued expenses	1,354,204	1,540,592
Short-term note	1,150,967	208,881
Total current liabilities	4,648,023	3,128,246
Asset retirement obligation	612,874	507,280
Term-note payable	20,129,670	20,229,801
Convertible notes payable, net of discount	4,929,068	-
Convertible notes conversion derivative liability	1,300,000	-
Total long-term liabilities	26,971,612	20,737,081
Total liabilities	31,619,635	23,865,327
Commitments and contingencies – Note 8	-	-
Preferred stock, 10,000,000 authorized, none issued and outstanding as of December 31, 2011 and 2010.	-	-
Common stock subject to redemption rights, $0.0001 par value; 0 and 10,625 shares issued and outstanding as of December 31, 2011 and December 31, 2010, respectively	-	86,257
Common Stock, $0.0001 par value: 100,000,000 shares authorized; 17,436,825 and 14,453,592 shares issued and outstanding (excluding 0 and 10,625 shares subject to redemption) as of December 31, 2011 and December 31, 2010, respectively	1,744	1,445
Additional paid-in capital	118,146,119	93,819,314
Accumulated deficit	(68,479,638)	(49,650,414)
Total shareholders' equity	49,668,225	44,170,345
Total liabilities and shareholders' equity	$ 81,287,860	$ 68,121,929

The accompanying notes are an integral part of these financial statements.

RECOVERY ENERGY, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2011	Year Ended December 31, 2010	March 6, 2009 (Inception) through December 31, 2009
Revenues:			
Oil sales	$ 7,148,110	$ 9,504,737	$ -
Gas sales	547,190	68,075	-
Operating fees	117,360	13,487	-
Realized gain on price hedges	625,043	570,233	-
Unrealizedlosses price hedges	(75,609)	(398,840)	-
Total revenues	8,362,094	9,757,692	-
Costs and expenses:			
Production costs	1,514,784	862,042	-
Production taxes	838,714	1,056,244	-
General and administrative (includes non-cash consideration of $6,656,152, $13,097,346, and $684,778 for the periods ended December 31, 2011, 2010 and 2009)	10,544,347	15,530,248	1,057,306
Depreciation, depletion,accretion, and amortization	4,347,117	5,036,648	-
Impairment of equipment	-	-	2,750,000
Impairment of evaluated properties	2,821,176	-	-
Bad debt expense	-	400,000	-
Fair value of common stock and warrants issued in aborted property acquisitions	-	-	8,404,106
Restructuring and related consulting costs	-	-	17,700,000
Total costs and expenses	20,066,138	22,885,182	29,911,412
Loss from operations	(11,704,044)	(13,127,490)	(29,911,412)
Other income	71,253	-	-
Convertible notes conversion derivative gain	3,821,792	-	-
Interest expense (includes non-cash interest expense of $ 4,993,997, $3,989,649, and $0 for the periods ended December 31, 2011, 2010 and 2009)	(8,218,225)	(6,640,209)	31
Unrealized gain on lock-up	-	28,666	-
Debt inducement expense	(2,800,000)	-	-
Net loss	$ (18,829,224)	$ (19,739,033)	$ (29,911,381)
Earnings per common share			
Basic and diluted	$ (1.21)	$ (2.15)	$ (12.19)
Weighted average shares outstanding:			
Basic and diluted	15,543,758	9,167,803	2,453,921

The accompanying notes are an integral part of these financial statements.

RECOVERY ENERGY, INC.
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
For the year ended December 31, 2011, December 31, 2010 and from March 6, 2009 (Inception) through December 31, 2009

	Common Stock Subject to Redemption		Common Stock				
	Shares	Amount	Shares	Amount	Additional Paid-In Capital	Accumulated Deficit	Total
Balance, March 6, 2009 (Inception)	$ -	-	-	$ -	$ -	$ -	$ -
Common stock issued in reverse merger	-	-	524,750	52	(33,957)	-	(33,905)
Common stock issued in exchange of debt	-	-	525,000	53	3,249,790	-	3,249,843
Common stock issued in lock-up agreement	21,250	172,516	-	-	-	-	-
Common stock issued in restructuring	-	-	1,250,000	125	17,499,500	-	17,499,625
Common stock issued in attempted acquisition	-	-	425,000	43	5,824,830	-	5,824,873
Common stock issued for cash	-	-	31,250	3	499,988	-	499,991
Restricted stock and performance options issued to employees and directors	-	-	-	-	684,778	-	684,778
Warrants issued for financing commitment	-	-	-	-	3,329,106	-	3,329,106
Common stock reacquired in attempted acquisition	-	-	(62,500)	(6)	(749,975)	-	(749,981)
1:4 Reverse stock split	-	-	-	-	808	-	808
Net loss	-	-	-	-	-	(29,911,381)	(29,911,381)
Balance, December 31, 2009	21,250	172,516	2,693,500	269	30,304,868	(29,911,381)	393,756
Common stock issued for property acquisitions	-	-	2,929,167	293	15,786,328	-	15,786,621

Common stock issued in connection with financing property acquisitions	-	-	1,250,000	125	5,249,500	-	5,249,625
Common stock issued for cash	-	-	3,978,789	398	14,924,142	-	14,924,540
Common stock issued for services	-	-	502,216	50	2,256,038	-	2,256,088
Restricted stock issued to employees and directors	-	-	2,235,797	223	8,375,327	-	8,375,550
Warrants exercised for cash	-	-	853,500	85	5,120,658	-	5,120,743
Warrants issued for cash, services and fees	-	-	-	-	11,712,671	-	11,712,671
Common stock no longer subject to redemption	(10,625)	(86,258)	10,625	1	86,258	-	86,258
1:4 Reverse stock split	-	-	-	-	3,525	-	3,525
Net loss	-	-	-	-	-	(19,739,033)	(19,739,033)
Balance, December 31, 2010	10,625	86,258	14,453,593	1,444	93,819,315	(49,650,414)	44,170,344
1:4 Reverse stock split	-	-	-	-	387	-	387
Common stock issued for property acquisitions	-	-	2,269,543	228	10,895,665	-	10,895,893
Common stock no longer subject to redemption (1)	(10,625)	(86,258)	10,625	1	86,254	-	86,255
Common stock issued in connection with interest payment of the financing	-	-	78,982	8	559,863	-	559,872
Common stock issued for services	-	-	10,000	1	81,996	-	81,997
Restricted stock issued to employees and directors	-	-	238,750	24	6,161,041	-	6,161,065
Warrants issued for cash	-	-	375,333	38	2,129,801	-	2,129,804
Warrants issued for debt extension	-	-	-	-	1,611,797		1,611,832

Debt conversion expense	-	-	-	-	2,800,000	-	2,800,000
Net loss	-	-	-	-	-	(18,829,224)	(18,829,224)
Balance, December 31, 2011	-	-	17,436,825	$ 1,744	$ 118,146,119	$ (68,479,638)	$ 49,668,225

The accompanying notes are an integral part of these financial statements.

RECOVERY ENERGY, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2011	Year Ended December 31, 2010	March 6, 2009 (Inception) through December 31, 2009
Cash flows from operating activities:			
Net loss	$ (18,829,224)	$ (19,739,033)	$ (29,911,381)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Impairment of equipment	-	-	2,750,000
Impairment of evaluated properties	2,821,176	-	-
Debt inducement and warrant modification expense	2,800,000	2,953,450	-
Common stock issued for convertible note interest	559,873	-	-
Bad debt expense	-	400,000	-
Common stock for services and compensation	6,566,152	8,701,263	884,778
Fair value of warrants issued	-	-	3,329,106
Non-cash restructuring costs	-	-	17,500,000
Loss on aborted property acquisitions	-	-	5,075,000
Changes in the fair value of commodity price derivatives	(549,434)	398,840	-
Compensation expense recognized for assignment of overrides	-	1,578,080	-
Amortization of deferred financing costs	4,446,911	3,989,649	-
Change in fair value of convertible notes conversion derivative	(3,821,792)	-	
Depreciation, depletion, and amortization and accretion of asset retirement obligation	4,347,117	5,036,648	-
Changes in operating assets and liabilities:			
Accounts receivable	73,940	(757,554)	(100,000)
Restricted cash	218,376	(1,129,665)	(20,876)
Other assets	39,451	(34,066)	15,627
Accounts payable and other accrued expenses	757,207	2,361,082	96,507
Net cash provided by (used in) operating activities	(570,247)	3,758,694	(381,239)
Cash flows from investing activities:			
Additions of evaluated properties and equipment (net of purchase price adjustment)	-	(25,580,793)	-
Acquisition of unevaluated properties	(9,433,073)	(18,560,412)	-
Drilling capital expenditures	(7,017,523)	(4,637,111)	-
Sale of unevaluated property interests	3,000,000	2,000,000	1,500,000
Sale of drilling rigs	-	100,000	-
Additions of office equipment	(83,727)	(55,767)	(750,470)
Proceeds from hedge settlement	226,203	-	-
Investment in operating bonds	(348)	(75,675)	(109,891)
Net cash provided by (used in) investing activities	(13,308,468)	(46,809,758)	639,639
Cash flows from financing activities:			
Proceeds from sale of common stock, units and exercise of warrants	2,129,870	28,132,727	500,000
Proceeds from debt	9,411,597	28,500,000	-
Common stock reacquired in attempted Church acquisition	-	-	(750,000)
Common stock issuable	-	(100,000)	100,000
Payment of debt	(483,774)	(8,061,319)	-
Net cash provided by (used in) financing activities	11,057,693	48,471,408	(150,000)
Net increase in cash and cash equivalents	(2,821,023)	5,420,344	108,400
Cash and cash equivalents, beginning of period	5,528,744	108,400	-
Cash and cash equivalents, end of period	$ 2,707,722	$ 5,528,744	$ 108,400

Supplemental disclosure of non-cash investing and financing activities:						
Cash paid for interest	$	3,201,312	$	2,655,131	$	-
Cash paid for income taxes	$	-	$	-	$	-
Non-cash transactions:						
Purchase of rigs for note payable	$	-	$	-	$	3,250,000
Sale of property for receivable	$	1,443,852	$	-	$	-
Debt issuance cost	$	400,000	$	-	$	-
Purchase of properties for common stock	$	10,895,893	$	15,787,500	$	8,025,000
Stock and warrants issued for deferred financing costs	$	1,611,832	$	6,867,735	$	-
Stock and warrants issued for prepaid financial advisory fees	$	-	$	1,234,510	$	-
Stock and warrants issued for prepaid financial office rent	$	81,997	$	-	$	-
Default on note in property acquisition	$	-	$	-	$	(2,200,000)
Property additions for asset retirement obligation	$	61,469	$	479,238	$	-
Stock issued for payment on long-term debt	$	559,872	$	-	$	-

The accompanying notes are an integral part of these financial statements.

RECOVERY ENERGY, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 – ORGANIZATION

On September 21, 2009, Universal Holdings, Inc. (“Universal”), a Nevada corporation, completed the acquisition of Coronado Acquisitions, LLC (“Coronado”). Under the terms of the acquisition, Coronado was merged into Universal. On October 12, 2009, Universal changed its name to Recovery Energy, Inc. (“Recovery”, “Recovery Energy”, “we”, “our”, and the “Company”). The Agreement was accounted for as a reverse acquisition with Coronado being treated as the acquirer for accounting purposes. Accordingly, the financial statements of Coronado have been adopted as the historical financial statements of Recovery.

The Company is an independent oil and gas exploration and production company focused on the Denver-Julesburg Basin (“DJ Basin”) where it holds 130,000 net acres. Recovery drills for, operates and produces oil and natural gas wells through the Company’s land holdings located in Wyoming, Colorado, and Nebraska.

All common stock share information is retroactively adjusted for the effect of a 4:1 reverse stock split that was effective October 19, 2011.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation and Principles of Consolidation

The financial statements included herein were prepared from the records of the Company in accordance with generally accepted accounting principles in the United States ("GAAP") and reflect all normal recurring adjustments which are, in the opinion of management, necessary to provide a fair statement of the results of operations and financial position for the interim periods.

Certain amounts in the December 31, 2010 consolidated financial statements have been reclassified to conform to the December 31, 2011 consolidated financial statement presentation. Such reclassifications had no effect on net income.

Use of Estimates in the Preparation of Financial Statements

The preparation of the financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of oil and gas reserves, assets and liabilities, and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. On an ongoing basis, management evaluates its estimates based on historical experience and on various other factors that the Company believes to be reasonable under the circumstances. Actual results could differ from those estimates.

Our most significant financial estimates are associated with our estimated proved oil and gas reserves as well as valuation of common stock used in various issuances of common stock, options and warrants. Significant financial estimates are also required for the analysis of impairment of oil and gas properties.

Principle of Consolidation

The accompanying consolidated financial statements include Recovery Energy, Inc. and its wholly−owned subsidiaries Recovery Oil and Gas, LLC, and Recovery Energy Services, LLC. All intercompany accounts and transactions have been eliminated in consolidation. Both subsidiaries were inactive and were dissolved in the 4th quarter of 2011.

Liquidity

Cash used in operating activities during the year ended December 31, 2011 was $.6 million and cash used in investing activities exceeded cash provided by financing activities by approximately $2.2 million. This net cash use contributed to a substantial decrease in our net working capital as of December 31, 2011. Expenditures subsequent to December 31, 2011 have continued to exceed cash receipts, causing a further reduction of the Company’s working capital position.

In the immediate term, the Company expects that additional capital will be required to fund its capital budget for 2012, partially to fund some of its ongoing overhead, and to provide additional capital to generally improve its working capital position. We anticipate that these capital requirements will be funded by a combination of capital raising activities, including the selling of additional debt and/or equity securities and the selling of certain assets. If we are not successful in obtaining sufficient cash sources to fund the aforementioned capital requirements, we may be required to curtail our expenditures, restructure our operations, sell assets on terms which may not be deemed favorable and/or curtail other aspects of our operations, including deferring portions of our 2012 capital budget.

Pursuant to our credit agreements with Hexagon, a substantial portion of our monthly net revenues derived from our producing properties is required to be used for debt and interest payments. In addition, our debt instruments contain provisions that, absent consent of the Lenders, may restrict our ability to raise additional capital.

Since inception, the Company raised approximately $72 million in cash generally through private placements of debt and equity securities. In December 2011, the Company sold certain undeveloped acreage for total proceeds of $4.5 million. During 2011, Hexagon agreed to temporarily suspend for five months the requirement to remit monthly net revenues of approximately $2,000,000 in the aggregate as payment on the Hexagon debt. In November 2011, Hexagon extended the maturity date of their notes to January 1, 2013, and also advanced an additional $309,000 to the Company. The Company repaid the $309,000 advance in February 2012. In March 2012, Hexagon extended the maturity date of their notes to June 30, 2013, and in connection therewith, the Company agreed to make minimum note payments of $325,000, effective immediately. The Company will continue to pursue alternatives to shore up its working capital position and to provide funding for its planned 2012 expenditures.

Cash and Cash Equivalents

Cash and cash equivalents include cash in banks and highly liquid debt securities which have original maturities of 90 days or less at the purchase date.

Restricted Cash

Restricted cash consists of severance and ad valorem tax proceeds which are payable to various tax authorities and amounts restricted pursuant to our loan agreements.

Accounts Receivable

The Company records estimated oil and gas revenue receivable from third parties at its net revenue interest. The Company also reflects costs incurred on behalf of joint interest partners in accounts receivable. Management periodically reviews accounts receivable amounts for collectability and records its allowance for uncollectible receivables under the specific identification method. The Company did not record any allowance for uncollectible receivables for years ended December 31, 2011or December 31, 2010. Receivables which derive from sales of certain oil and gas production are collateral for our Loan Agreements (see Note 7).

During the year ended December 31, 2010, the Company wrote off a note receivable for $400,000 as a bad debt expense (see Note 13). During the year ended December 31, 2011 and period ended December 31, 2009, no receivable amounts were written off to bad debt expense.

Assets Held For Sale

Assets held for sale are recorded at the lower of cost or estimated net realizable value. As of December 31, 2011 and 2010, the Company did not have any assets held for sale.

Concentration of Credit Risk

The Company's cash, cash equivalents and short-term investments are invested at major financial institutions primarily within the United States. At December 31, 2011 and December 2010, the Company's cash and cash equivalents were maintained in accounts that are insured up to the limit determined by the federal governmental agency. The Company may at times have balances in excess of the federally insured limits.

The Company's receivables are comprised of oil and gas revenue receivables and joint interest billings receivable. The amounts are due from a limited number of entities. Therefore, the collectability is dependent upon the general economic conditions of the few purchasers and joint interest owners. The receivables are not collateralized. However, to date the Company has had minimal bad debts.

Significant Customers

During the year ended December 31, 2011 and December 31, 2010, approximately 76% and 64%, respectively, of the Company's revenue sold to one customer, Shell Trading (US). However, the Company does not believe that the loss of a single purchaser, including Shell Trading (US), would materially affect the Company's business because there are numerous other purchasers in the area in which the Company sells its production.

Oil and Gas Producing Activities

The Company follows the full cost method of accounting for oil and gas operations whereby all costs related to the exploration, development and acquisition of oil and natural gas reserves are capitalized. Such costs include land acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling, developing and completing productive wells and/or plugging and abandoning non-productive wells, and any other costs directly related to acquisition and exploration activities. Proceeds from property sales are generally applied as a credit against capitalized exploration and development costs, with no gain or loss recognized, unless such a sale would significantly alter the relationship between capitalized costs and the proved reserves attributable to these costs. A significant alteration would typically involve a sale of 25% or more of proved reserves.

Depletion of exploration and development costs and depreciation of production equipment is computed using the units-of-production method based upon estimated proved oil and gas reserves. Costs included in the depletion base to be amortized include (a) all proved capitalized costs including capitalized asset retirement costs net of estimated salvage values, less accumulated depletion, (b) estimated future development cost to be incurred in developing proved reserves, and (c) estimated dismantlement and abandonment costs, net of estimated salvage values, that are not otherwise included in capitalized costs.

Under the full cost method of accounting, capitalized oil and gas property costs less accumulated depletion and net of deferred income taxes may not exceed an amount equal to sum of i.) the present value, discounted at 10%, of estimated future net revenues from proved oil and gas reserves, plus ii.) the cost of unproved properties not subject to amortization (without regard to estimates of fair value), or estimated fair value, if lower, of unproved properties that are not subject to amortization. Should capitalized costs exceed this ceiling, an impairment expense is recognized. As of December 31, 2011, the Company recognized an impairment of $2,821,176. During the year ended December 31, 2010 and period ended December 31, 2009, no impairment charges were recognized.

The present value of estimated future net revenues was computed by applying a twelve month average of the first day of the month price of oil and gas to estimated future production of proved oil and gas reserves as of period-end, less estimated future expenditures to be incurred in developing and producing the proved reserves (assuming the continuation of existing economic conditions), less any applicable future taxes.

Unproved Properties

The costs of unproved properties are withheld from the depletion base until it is determined whether or not proved reserves can be assigned to the properties. The properties are reviewed quarterly for impairment. When proved reserves are assigned to such properties or one or more specific properties are deemed to be impaired, the cost of such properties or the amount of the impairment is added to costs subject to depletion calculations. During the year ended December 31, 2011, the Company impaired $3,861,875 of unproved property value. During the years ending December 31, 2010 and December 31, 2009, no impairment was recorded.

Wells in Progress

Wells in progress represent wells that are currently in the process of being drilled or completed or otherwise under evaluation as to their potential to produce oil and gas reserves in commercial quantities. Such wells continue to be classified as wells in progress and withheld from the depletion calculation and the ceiling test until such time as either proved reserves can be assigned, or the wells are otherwise abandoned. Upon either the assignment of proved reserves or abandonment, the costs for these wells are then transferred to exploration and development costs and become subject to both depletion and the ceiling test calculations in future periods. At December 31, 2011, the Company had two wells in progress, both of which have been drilled and completed and are pending evaluation as to their potential to produce commercial quantities of oil and gas reserves.

Deferred Financing Costs

As of December 31, 2011 and December 31, 2010, the Company recorded unamortized deferred financing costs of approximately $2.3 million and $3.2 million, respectively, related to the closing of its loans and credit agreements (see Note 7). Deferred financing costs include origination (warrants issued and overriding royalty interests assigned to our lender), legal and engineering fees incurred in connection with the Company's credit facility, which are being amortized over the term of the credit facility. The Company recorded amortization expense of approximately $5.0 million and $4.0 million, respectively, in the years ended December 31, 2011 and December 31, 2010.

Prepaid Advisory Fees

The Company accounts for prepaid advisory services with the total consideration amortized over the underlying service agreement period. As of December 31, 2011 and 2010 prepaid financial advisory fees were approximately $574,000 and $979,000, respectively. The prepaid fees were paid with non-cash consideration (shares of our common stock and warrants exercisable for shares of our common stock issued to our financial advisors) initially issued in 2010 in the amount of $1,234,000. This amount is being amortized over the term of the underlying agreement. The Company amortized $405,000 and $247,000, respectively of prepaid fees during the years ended December 31, 2011 and December 31, 2010.

The following schedule details the future expense of the prepaid advisory fees.

2012	$	405,289
2013		168,871
Total	$	574,160

Property and Equipment

Property and equipment (other than the full cost pool) are stated at cost. Depreciation is calculated using the straight-line method over the estimated useful lives of the assets. The estimated useful lives of property and equipment range from one to 7 years. The Company recorded $34,000 and $5,000 of depreciation for the years ended December 31, 2011 and December 31, 2010, respectively.

Impairment of Long-lived Assets

The Company accounts for long-lived assets (other than the full cost pool), which include property and equipment, prepaid advisory fees, and identifiable intangible assets with finite useful lives (subject to amortization, depletion, and depreciation), whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability is measured by comparing the carrying amount of an asset to the expected undiscounted future net cash flows generated by the asset. If it is determined that the asset may not be recoverable, and if the carrying amount of an asset exceeds its estimated fair value, an impairment charge is recognized to the extent of the difference.

For the period ended December 31, 2009, the Company recorded impairment expense of $2,750,000 related to the two medium depth drilling rigs. As of December 31, 2011 and 2010, no impairment has been recorded for long lived assets other than the impairment of its capitalized oil and gas property costs during 2011 as discussed above.

Fair Value of Financial Instruments

As of December 31, 2011 and 2010, the carrying value of cash and cash equivalents, short-term investments, accounts receivable, accounts payable, accrued expenses, interest payable and customer deposits approximates fair value due to the short-term nature of such items. The carrying value of other long-term liabilities approximates fair value as the related interest rates approximate rates currently available to Recovery Energy, certain other assets and liabilities are measured at fair value as discussed in Note 6.

Commodity Derivative Instrument

The Company utilizes swaps to reduce the effect of price changes on a portion of our future oil production. On a monthly basis, a swap requires us to pay the counterparty if the settlement price exceeds the strike price and the same counterparty is required to pay us if the settlement price is less than the strike price. The objective of the Company's use of derivative financial instruments is to achieve more predictable cash flows in an environment of volatile oil and gas prices and to manage its exposure to commodity price risk. While the use of these derivative instruments limits the downside risk of adverse price movements, such use may also limit the Company's ability to benefit from favorable price movements. The Company may, from time to time, add incremental derivative contracts to hedge additional production, restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of the Company's existing positions (see Note 5).

The use of derivatives involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts. The Company's derivative contracts are currently with one counterparty. The Company has netting arrangements with the counterparty that provide for the offset of payables against receivables from separate derivative arrangements with the counterparty in the event of contract termination. The derivative contracts may be terminated by a non-defaulting party in the event of default by one of the parties to the agreement (see Note 5).

Revenue Recognition

The Company recognizes oil and gas revenues from its interests in producing wells when production is delivered to, and title has transferred to, the purchaser and to the extent the selling price is reasonably determinable.

Asset Retirement Obligation

The Company incurs retirement obligations for certain assets at the time they are placed in service. The fair values of these obligations are recorded as liabilities on a discounted basis. The costs associated with these liabilities are capitalized as part of the related assets and depreciated. Over time, the liabilities are accreted for the change in their present value.

For purposes of depletion calculations, the Company also includes estimated dismantlement and abandonment costs, net of salvage values, associated with future development activities that have not yet been capitalized as asset retirement obligations.

Asset retirement obligations incurred are classified as Level 3 (unobservable inputs) fair value measurements. The asset retirement liability is allocated to operating expense using a systematic and rational method. As of December 31, 2011 and 2010, the Company recorded a net asset of $592,150 and $540,707 and a related liability of $612,874 and $507,280 (see Note 6).

The information below reconciles the value of the asset retirement obligation for the periods presented:

	For the years ended December 31,	
	2011	2010
Balance, beginning of period	$ 507,280	-
Liabilities incurred	61,469	478,208
Accretion expense	44,125	28,042
Change in estimate	-	1,030
Balance, end of period	$ 612,874	$ 507,280

Share Based Compensation

The Company measures the fair value of share-based compensation expense awards made to employees and directors, including stock options, restricted stock and employee stock purchases related to employee stock purchase plans, on the date of grant using an option-pricing model. The value of the portion of the award that is ultimately expected to vest is recognized as an expense ratably over the requisite service periods. The measurement of share-based compensation expense is based on several criteria, including but not limited to the valuation model used and associated input factors, such as expected term of the award, stock price volatility, risk free interest rate, dividend rate and award cancellation rate. These inputs are subjective and are determined using management's judgment. If differences arise between the assumptions used in determining share-based compensation expense and the actual factors, which become known over time, Recovery may change the input factors used in determining future share-based compensation expense.

Recovery accounts for option grants to non-employees whereby the fair value of such options is determined using the Black-Scholes option pricing model at the earlier of the date at which the non-employee's performance is complete or a performance commitment is reached (Note 12).

Warrant Modification Expense

The Company accounts for the modification of warrants as an exchange of the old award for a new award. The incremental value is measured as the excess, if any, of the fair value of the modified award over the fair value of the original award immediately before modification, and is either expensed as a period expense or amortized over the performance or vesting date. We estimate the incremental value of each warrant using the Black-Scholes option pricing model. The Black-Scholes model is highly complex and dependent on key estimates by management. The estimate with the greatest degree of subjective judgment is the estimated volatility of our stock price (Note 12).

Loss per Common Share

Basic earnings (loss) per share is based on the weighted average number of common shares outstanding during the period presented. In addition to common shares outstanding, diluted loss per share is computed using the weighted-average number of common shares outstanding plus the number of common shares that would be issued assuming exercise or conversion of all potentially dilutive common shares. Potentially dilutive securities, such as stock grants and stock purchase warrants, are excluded from the calculation when their effect would be anti-dilutive. For the years ended December 31, 2011 and December 31, 2010, outstanding warrants and derivatives of 5,638,900 and 5,764,233, respectively, have been excluded from the diluted share calculations as they were anti-dilutive as a result of net losses incurred. Accordingly, basic shares equal diluted shares for all periods presented. On October 16, 2011, the Company affected a 4:1 reverse stock split.

Income Taxes

For tax reporting, the Company continues to file its tax returns on an April 30 year end, which is the legal tax year end of its predecessor.

The Company uses the asset liability method in accounting for income taxes. Deferred tax assets and liabilities are recognized for temporary differences between financial statement carrying amounts and the tax bases of assets and liabilities, and are measured using the tax rates expected to be in effect when the differences reverse. Deferred tax assets are also recognized for operating loss and tax credit carry forwards. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the results of operations in the period that includes the enactment date. A valuation allowance is used to reduce deferred tax assets when uncertainty exists regarding their realization.

We recognize tax benefits only for tax positions that are more likely than not to be sustained upon examination by tax authorities. The amount recognized is measured as the largest amount of benefit that is greater than 50 percent likely to be realized upon settlement. A liability for "unrecognized tax benefits" is recorded for any tax benefits claimed in our tax returns that do not meet these recognition and measurement standards. As of December 31, 2011, the Company has determined that no liability is required to be recognized.

Our policy is to recognize any interest and penalties related to unrecognized tax benefits in income tax expense. However, we did not accrue interest or penalties at December 31, 2011 and December 31, 2010, because the jurisdiction in which we have unrecognized tax benefits does not currently impose interest on underpayments of tax and we believe that we are below the minimum statutory threshold for imposition of penalties. We do not expect that the total amount of unrecognized tax benefits will significantly increase or decrease during the next 12 months. The earliest years remaining subject to examination are April 30, 2010 and 2009.

Recently Issued Accounting Pronouncements

The Company did not adopt any new authoritative guidance for the year ended December 31, 2011 that had a material impact on its financial statements.

NOTE 3 – OIL AND GAS PROPERTIES & OIL AND GAS PROPERTIES ACQUISITIONS AND DIVESTITURES

DJ Basin Properties Acquisitions – Accounted for as a Business Combination

During the fourth quarter of 2009, the Company pursued a number of acquisition opportunities. The Company entered into two purchase and sale agreements with Edward Mike Davis, LLC and affiliates ("Davis") for the purchase of multiple oil and gas properties. The Company was not successful in fulfilling the requirements under the purchase and sale agreements and forfeited 1,450,000 shares of our common stock with an estimated fair value of $5,075,000.

In January 2010, the Company acquired the Wilke Field from Davis for $4,500,000. The Company simultaneously entered into a credit agreement with Hexagon to finance 100% of the purchase of the Wilke Field properties. Hexagon received 1,000,000 shares of the Company's common stock in connection with the financing. The Company recorded $2.25 million in deferred financing costs related to the shares issued in conjunction with the loan (see Note 7).

In March 2010, the Company acquired the Albin Field properties from Davis for $6,000,000 and 550,000 shares of common stock with an estimated fair value of $412,500. The Company simultaneously entered into a loan agreement with Hexagon to finance 100% of the cash portion of the purchase price. The Company recorded approximately $737,822 in deferred financing costs related to 750,000 shares of the Company's common stock and a one-half percent overriding royalty in the leases and wells in connection with the financing from Hexagon (see Note 7).

In April 2010, the Company acquired the State Line Field properties from Davis for $15,000,000 and 2,500,000 shares of common stock with an approximate fair value of $1,875,000. The Company simultaneously entered into a loan agreement with Hexagon to finance 100% of the cash portion of the purchase price. The Company recorded approximately $2,780,775 in deferred financing costs related to 3,250,000 shares of the Company's common stock, 2,000,000 warrants to acquire the Company's common stock at $2.50 per share and a one percent overriding royalty interest in connection with the financing from Hexagon (see Note 7).

All three of the acquisitions above were recorded at their fair values as of the acquisition date. The following table summarizes the fair values of assets acquired and liabilities assumed for each acquisition as of the related acquisition date:

	Wilke Field	Albin Field	State Line Field
Consideration given:			
Cash payment funded by debt	$ 4,500,000	$ 6,000,000	$ 15,000,000
Stock	-	412,500	1,875,000
Total consideration attributable to allocation	$ 4,500,000	$ 6,412,500	$ 16,875,000
Allocation of purchase price:			
Proved oil and gas properties	$ 4,418,267	$ 4,675,099	$ 15,529,268
Unproved oil and gas properties	83,200	1,791,619	1,070,975
Total fair value of oil and gas properties acquired	4,501,467	6,466,718	16,600,243
Oil and gas revenue receivable	195,594	-	-
Total assets	4,697,061	6,466,718	16,600,243
Accounts payable	-	-	(52,147)
Asset retirement obligation	(197,061)	(54,218)	(149,151)
Total liabilities acquired	(197,061)	(54,218)	(201,298)
Net assets acquired	$ 4,500,000	$ 6,412,500	$ 16,398,945
Supplemental information:			
Value attributable to ORRI paid to lender	$ -	$ (175,322)	$ (158,685)
Value attributable to ORRI awarded to management	$ (125,220)	$ (701,290)	$ (317,370)

The following unaudited supplemental pro forma information presents the results of operations for the years ended December 31, 2010 and 2009, as if the Wilke, Albin, and State Line acquisitions had occurred as of the earliest period presented, January 1, 2009. These unaudited pro forma results of operations are based on the historical financial statements and related notes of the Company, and the related historical audited statements of revenue and direct expenses for the Wilke, Albin and State Line acquisitions included in the related filings on Form 8-K. These pro forma results of operations contain adjustments to depreciation, depletion and amortization for the effects of purchase price allocation, and to interest expense and amortization of deferred financing costs related to financing the acquisitions. The pro forma results are presented for informational purposes only and are not necessarily indicative of what actually would have occurred if the acquisitions had been completed as of the beginning of the period, nor are they necessarily indicative of future results.

	For the Year Ended December 31,	
	2010	2009
	(Unaudited)	(Unaudited)
Operating revenues	$ 12,941,108	$ 6,070,500
Operating loss	$ (10,599,304)	$ (29,001,745)
Net loss	$ (19,063,015)	$ (33,489,536)
Pro forma loss per common share:		
Basic and diluted	$ (2.08)	$ (12.92)

Also in May 2010, the Company acquired additional undeveloped leasehold acreage and certain overriding royalty interests on existing Company owned acreage and wells in the DJ Basin from Davis for 2,000,000 shares of common stock valued at $1,500,000 and a cash payment of $20 million.

In August 2010, the Company farmed into approximately 240 net acres in exchange for carrying Davis, the lease owner, for a 26% working interest in one well, which has been drilled. The Company also farmed into approximately 533 net acres in the state of Nebraska in exchange for carrying Davis, the lease owner, for a 33% working interest in one well which has been drilled.

In November 2010, the Company purchased certain oil and gas interests of approximately 33,800 net acres located in Laramie County and Goshen County, Wyoming, and Banner County, Kimball County, and Scotts Bluff County, Nebraska from Davis. Additionally, the Company acquired rights below the base of the Greenhorn on approximately 23,000 net acres in Laramie County and Goshen County, Wyoming, and Banner County and Kimball County, Nebraska. The Company issued 6,666,667 shares of our common stock to acquire the property with an estimated fair value of approximately $12,000,000.

In December 2010, the Company entered into an acquisition and development agreement with TRW Exploration, LLC (a related party, see note 9) whereby TRW paid $2,000,000 for the purchases of an interest in approximately 2,000 net undeveloped acres and also agreed to carry the Company's 40% interest in two horizontal wells to be drilled on lands defined by the agreement. TRW subsequently funded the drilling and completion costs of two horizontal wells on the lands covered by the leases, at a total cost of approximately $7 million. This agreement was terminated in December, 2011 and TRW sold back its interest in the wells along with all of its rights to the undeveloped acreage, in consideration for the issuance by the Company of 1,500,000 shares of unregistered common stock valued at $4,875,000. Additional amounts were incurred in drilling the wells and were paid by the Company. The Company allocated $2 million of this purchase price to the undeveloped leases, and the remainder to the purchase of the two wells.

The two wells are in progress and currently being evaluated as to their potential to establish commercial production of oil and gas. These wells are carried as wells in progress as of December 31, 2011 at a total cost of $6.4 million.

In February 2011, the Company purchased undeveloped oil and gas leases from various private individuals for $1,253,780 in cash and $653,449 in stock in the Grover Field and surrounding area in Weld County, Colorado, and Goshen County, Wyoming.

In March 2011, the Company purchased undeveloped oil and gas interests located in Laramie County, Wyoming. The purchase price was $6,469,552 cash and shares of common stock valued at $5,798,546 in stock. The Company also closed on two acquisitions of undeveloped oil and gas leases from various private individuals for a combined $551,519 in cash in Goshen County, Wyoming.

DJ Basin Properties Divestitures

Effective December 31, 2011 the Company sold 2,838 net acres of undeveloped leases for consideration of approximately $4.5 million. A gain of $1.8 million related to the sale of this acreage was applied as a credit to the carrying costs of evaluated oil and gas properties.

Depreciation, depletion and amortization ("DD&A") expenses related to the proved properties were approximately $4,274,215 and $5,036,000 for the years ended December 31, 2011 and December 31, 2010, respectively. During the year ended December 31, 2011, the company impaired the carrying costs of its evaluated oil and gas properties by $2.8 million as a result of an excess of carrying costs above the applicable ceiling threshold. Prior to January 1, 2010, the Company did not own any oil and gas properties therefore we did not incur DD&A expense in 2009.

The following table sets forth a summary of oil and gas property costs (net of divestitures) not being amortized as of December 31, 2011:

		As of December 31, 2011
Leasehold acquisitions		
2010	$	33,605,594
2011		12,091,887
Unevaluated properties		45,697,481
Wells in progress exploration 2011		6,425,509
Total	$	52,122,990

The Company plans to evaluate exploration costs (wells-in progress) in 2012 and will likely develop, sell or reclassify to evaluated properties its inventory of unevaluated leasehold over the next three years. Included in its inventory of unevaluated leases are certain undeveloped leases with an approximate carrying value of $11 million that are being held and extended by the conducting of continuous operations on the two wells in progress. If commercial production is not eventually established in one or both of the two wells in progress, some or all of these leases may expire, and require such cases to be reclassified to evaluated property and subject to the Company's full cost lid calculation.

NOTE 4 – WELLS IN PROGRESS

The following table reflects the net changes in capitalized additions to wells in progress during 2010 and 2009:

	For the Year Ended December 31, 2011	2010
Beginning balance	$ 1,219,254	-
Additions to capital wells in progress costs	8,904,532	1,219,254
Reclassifications to proved properties	(3,698,563)	-
Ending balance	$ 6,425,509	$ 1,219,254

All wells in progress have been capitalized for less than one year.

NOTE 5 - FINANCIAL INSTRUMENTS AND DERIVATIVES

Periodically, the Company enters into various commodity derivative financial instruments intended to hedge against exposure to market fluctuations of oil prices. During the year ended December 31, 2011, the Company terminated and settled certain future commodity swaps resulting in a realized gain of approximately $625,000.

As of December 31, 2011, the Company maintained an active commodity swap for 100 barrels per day through December 31, 2012, at a price of $96.25 per barrel.

The amount of gain (loss) recognized in income related to our derivative financial instruments was as follows:

	For the Year Ended December 31, 2011	2010	2009(1)
Realized gain on oil price hedges	$ 625,043	$ 570,233	$ -
Unrealized loss oil price hedges	$ (75,609)	$ (398,840)	$ -

(1) Prior to January 1, 2010, the Company did not enter any derivative financial instruments.

Unrealized gains and losses resulting from derivatives are recorded at fair value on the consolidated balance sheet and changes in fair value are recognized in the unrealized gain (loss) on hedge contracts line on the consolidated statement of operations. Realized gains and losses resulting from the contract settlement of derivatives are recorded in the realized gain (loss) line on the consolidated statement of income. As of December 31, 2011, the Company recorded an unrealized loss on its only active swap of $75,609.

NOTE 6 - FAIR VALUE OF FINANCIAL INSTRUMENTS

The Company measures fair value of its financial assets on a three-tier value hierarchy, which prioritizes the inputs used in the valuation methodologies in measuring fair value:

- Level 1 – Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 – Include other inputs that are directly or indirectly observable in the marketplace.
- Level 3 – Unobservable inputs which are supported by little or no market activity.

The fair value hierarchy also requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value.

The Company measures its cash equivalents and investments at fair value. The Company's cash equivalents, short-term investments, accounts receivable, accounts payable, accrued expenses, interest payable and customer deposits are primarily classified within Level 1. Cash equivalents and short-term investments are valued primarily using quoted market prices utilizing market observable inputs.

Derivative Instruments

The Company determines its estimate of the fair value of derivative instruments using a market approach based on several factors, including quoted market prices in active markets, quotes from third parties, and the credit rating of its counterparty. The Company also performs an internal valuation to ensure the reasonableness of third-party quotes.

In evaluating counterparty credit risk, the Company assessed the possibility of whether the counterparty to the derivative would default by failing to make any contractually required payments. The Company considered that the counterparty is of substantial credit quality and has the financial resources and willingness to meet its potential repayment obligations associated with the derivative transactions.

At December 31, 2011, the types of derivative instruments utilized by the Company included commodity swaps (see Note 5). The oil derivative markets are highly active. Although the Company's economic hedges are valued using public indices, the instruments themselves are traded with third-party counterparties and are not openly traded on an exchange. As such, the Company has classified these instruments as Level 2.

Asset Retirement Obligation

The income valuation technique is utilized determine the fair value of its asset retirement obligation liability at the point of inception by taking into account 1) the cost of abandoning oil and gas wells, which is based on the Company's historical experience for similar work, or estimates from independent third-parties; 2) the economic lives of its properties, which is based on estimates from reserve engineers; 3) the inflation rate; and 4) the credit adjusted risk-free rate, which takes into account the Company's credit risk and the time value of money. Given the unobservable nature of the inputs, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs.

Convertible Notes Payable Conversion Feature

In February 2011, the Company issued in a private placement $8,400,000 aggregate principal amount of three year 8% Senior Secured Convertible Debentures ("Debentures") with a group of accredited investors. As of December 31, 2011, the Debentures are convertible at any time at the holders' option into shares of Recovery Energy common stock at $4.25 per share, subject to certain adjustments, including the requirement to reset the conversion price based upon any subsequent equity offering at a lower price per share amount. The Company engaged a third party to complete a valuation of this conversion feature as of December 31, 2011 (see Note 7). The valuation was completed using Level 3 inputs.

The following table provides a summary of the fair values of assets and liabilities measured at fair value:

December 31, 2011

	Level 1	Level 2	Level 3	Total
Liability				
Derivative instruments	$ -	$ (75,609)	$ -	$ (75,609)
Convertible notes payable Conversion feature	-	-	(1,300,000)	(1,300,000)
Total liability at fair value	$ -	$ (75,609)	$ (1,300,000)	$ (1,375,609)

December 31, 2010

	Level 1		Level 2		Level 3		Total	
Liability								
Derivative instruments	$	-	$	(398,840)	$	-	$	(398,840)
Total liability at fair value	$	-	$	(398,840)	$	-	$	(398,840)

The following table provides a summary of changes in fair value of the Company's Level 3 financial assets and liabilities as of December 31, 2011:

	Convertible debt feature (1)
Beginning balances, December 31, 2010	-
Additions of convertible debt feature	(1,300,000)
Ending balance as of December 31, 2011	(1,300,000)

(1) The Company entered into the convertible debt during the year ended December 31, 2011.

The Company did not have any transfers of assets or liabilities between Level 1, Level 2 or Level 3 of the fair value measurement hierarchy during the twelve months ended December 31, 2011 and December 31, 2010.

NOTE 7 - LOAN AGREEMENTS

Term Notes

The Company entered into three separate loan agreements with Hexagon Investments, LLC ("Hexagon") during 2010. All three loans bear annual interest of 15% and mature on June 30, 2013.

Effective January 29, 2010, the Company entered into a $4.5 million loan agreement, with an original maturity date of December 1, 2010. Effective March 25, 2010, the Company entered into a $6.0 million loan agreement, with an original maturity date of December 1, 2010. Effective April 14, 2010, the Company entered into a $15.0 million loan agreement, with an original maturity date of December 1, 2010. All three loan agreements have similar terms, including customary representations and warranties and indemnification, and require the Company to repay the notes with the proceeds of the monthly net revenues from the production of the acquired properties. The loans contain cross collateralization and cross default provisions and are collateralized by mortgages against a portion of the Company's developed and undeveloped leasehold acreage as well as all related equipment purchased in the Wilke Field, Albin Field, and State Line Field acquisitions.

The Company entered into a loan modification agreement on May 28, 2010, which extended the maturity date of the loans to December 1, 2011. In consideration for extending the maturity of the loans, Hexagon received 250,000 warrants with an exercise price of $6.00 per share. The loan modification agreement also required the Company to issue 250,000 five year warrants to purchase common stock at $6.00 per share to Hexagon if the Company did not repay the loans in full by January 1, 2011. Since the loans were not paid in full by January 1, 2011, the Company issued 250,000 additional warrants with an exercise price of $6.00 per share to Hexagon which was valued at approximately $1,600,000. This amount was recorded as a deferred financing cost and is being amortized over the remaining term of the loan.

In December 2010, Hexagon extended the maturity to September 1, 2011. During the last half of 2011, Hexagon agreed to temporarily suspend for five months the requirement to remit monthly net revenues in the total amount of approximately $2 million as payment on the notes. In November 2011, Hexagon extended the maturity to January 1, 2013. In March 2012, Hexagon agreed to extend the maturity of the notes to June 30, 2013, and in connection there with, the Company agreed to make minimum monthly note payments of $325,000, effective immediately. In November 2011, Hexagon also temporarily advanced the Company an additional amount of $309,000, which was repaid in full in February 2012.

The Company is subject to certain financial and non-financial covenants with respect to the Hexagon loan agreements. As of December 31, 2011, the Company was in compliance with all covenants under the facilities. If any of the covenants are violated, and the Company is unable to negotiate a waiver or amendment thereof, the lender would have the right to declare an event of default and accelerate all principal and interest outstanding.

Convertible Notes Payable

In February 2011, the Company completed a private placement of $8,400,000 aggregate principal amount of three year 8% Senior Secured Convertible Debentures (the "Debentures") with a group of accredited investors. Initially, the Debentures were convertible at any time at the holders' option into shares of Recovery Energy common stock at $9.40 per share, subject to certain adjustments, including the requirement to reset the conversion price based upon any subsequent equity offering at a lower price per share amount. Interest on the Debentures is payable quarterly on each May 15, August 15, November 15 and February 15 in cash or at the Company's option in shares of common stock, valued at 95% of the volume weighted average price of the common stock for the 10 trading days prior to an interest payment date. The Company can redeem some or all of the Debentures at any time. The redemption price is 115% of principal plus accrued interest. If the holders of the Debentures elect to convert the Debentures, following notice of redemption, the conversion price will include a make-whole premium equal to the remaining interest through the 18 month anniversary of the original issue date of the Debentures, payable in common stock. T.R. Winston & Company LLC acted as placement agent for the private placement and received $400,000 of Debentures equal to 5% of the gross proceeds from the sale. The Company is amortizing the $400,000 over the life of the loan as deferred financing costs. The Company amortized $88,888 of deferred financing costs into interest expense during the year ended December 31, 2011 and has $311,112 of deferred financing costs to be amortized over a straight-line basis until January 2014.

In December, 2011, the Company agreed to amend the Debentures to lower the conversion price to $4.25 from $9.40 per share. Therefore, the Debenture are currently convertible into shares of common stock. This amendment was consideration to the Debenture holders in exchange for their agreement to release a mortgage on certain properties so the properties could be sold. The sale of these properties was completed effective December 31, 2011.

The Company engaged a third party valuation firm to complete a valuation of both the conversion feature and the inducement. This valuation resulted in an estimate of the inducement expense of $2.8 million and estimate of the derivative liability as of December 31, 2011 of $1.3 million. A previous independent valuation of the derivative liability estimated the derivative liability as of March 31, 2011 at approximately $5.1 million. The reduction in the derivative value from $5.1 million as of March 31, 2011 to $1.3 million as of December 31, 2011 resulted in a derivative gain of $3.8 million during the year ended December 31, 2011. As of December 31, 2011, the convertible debt is recorded as follows:

	As of December 31, 2011
Convertible debt	8,400,000
Debt discount	(3,470,932)
Total convertible debt, net	4,929,068

Annual debt maturities for our debt under our term notes and convertible notes payable obligations as of December 31, 2011 are as follows:

2012	1,150,966
2013	20,129,670
2014	8,400,000
Thereafter	--
Total	29,680,636

Interest Expense

For the years ending December 31, 2011 and December 31, 2010, the Company incurred interest expense of approximately $8,218,000 and $6,600,000, respectively, of which approximately $5.0 million and $4.0 million, respectively, were non-cash interest expense related to the amortization of the deferred financing costs, accretion of the convertible notes payable discount, and convertible notes payable interest paid in stock.

NOTE 8 - COMMITMENTS and CONTINGENCIES

Environmental and Governmental Regulation

At December 31, 2011, there were no known environmental or regulatory matters which are reasonably expected to result in a material liability to the Company. Many aspects of the oil and gas industry are extensively regulated by federal, state, and local governments in all areas in which the Company has operations. Regulations govern such things as drilling permits, environmental protection and pollution control, spacing of wells, the unitization and pooling of properties, reports concerning operations, royalty rates, and various other matters including taxation. Oil and gas industry legislation and administrative regulations are periodically changed for a variety of political, economic, and other reasons. As of December 31, 2011, the Company had not been fined or cited for any violations of governmental regulations that would have a material adverse effect upon the financial condition of the Company.

Legal Proceedings

The Company may from time to time be involved in various other legal actions arising in the normal course of business. In the opinion of management, the Company's liability, if any, in these pending actions would not have a material adverse effect on the financial positions of the Company. The Company's general and administrative expenses would include amounts incurred to resolve claims made against the Company.

Potential Stock Grants Under Employment/Appointment Agreements

Until May 2010, the employment agreements for our chief executive officer and former chief financial officer contained provisions which provided these individuals additional stock grants if the Company achieved certain market capitalization milestones. In May 2010, the employment agreements were modified and our chief executive officer and former chief financial officer were no longer entitled to stock grants based on market capitalization milestones.

Operating Leases

The Company leases an office space under a one year operating lease in Denver, Colorado. Rent expense for the years ended December 31, 2011 and December 31, 2010, was $82,068 and $54,500, respectively. The Company will have minimum lease payments of $72,000 for the year ending December 31, 2012.

NOTE 9 - RELATED PARTY TRANSACTIONS

Since its inception, five property acquisitions the Company completed have been with the same seller, Davis. As of December 31, 2011, Davis owned approximately 19.1 % of the common stock of the Company. The cash portion of the purchase price for the first three acquisitions was financed with loans from Hexagon, which owned approximately 15.7% of the stock issued and outstanding at December 31, 2011. Hexagon received overriding royalty interests in both the Albin Field assets and the State Line Field assets. Hexagon also received warrants to purchase 500,000 shares of the Company's common stock at $10.00 per share in connection with the financing of an acquisition and warrants to purchase 250,000 shares the Company's common stock for $6.00 per share in connection with amendments to the loan agreements. A representative of Hexagon also served on the Company's Board of Directors, until his resignation on January 31, 2012.

The Company entered into an exploration and development agreement with TRW to drill two wells. The joint venture partners of TRW are also shareholders of the Company.

NOTE 10 - INCOME TAXES

The tax effects of temporary differences that gave rise to the deferred tax liabilities and deferred tax assets as of December 31, 2011 and 2010 were:

	2011	2010
Deferred tax assets:		
Oil and gas properties and equipment	$ (515,123)	$ (1,335,490)
Net operating loss carry-forward	11,291,513	7,285,426
Share based compensation	4,675,241	3,902,007
Abandonment obligation	205,145	188,728
Derivative instruments	176,514	148,384
Other	(91,304)	(30,896)
Total deferred tax asset	15,741,986	10,158,159
Valuation allowance	(15,741,986)	(10,158,159)
Net deferred tax asset	$ -	$ -

Reconciliation of the Company's effective tax rate to the expected federal tax rate is:

	2011	2009
Effective federal tax rate	35.00%	35.00%
Effect of permanent differences	-7.54%	-21.78%
State tax rate	2.20%	2.20%
Change in rate	0.00%	-0.23%
Other	0.00%	3.07%
Valuation allowance	-29.66%	-18.26%
Net	0%	0%

At December 31, 2011 and 2010, the Company had net operating loss carry-forwards for federal income tax purposes of approximately $25,957,000 and $19,582,000, respectively,that may be offset against future taxable income. The Company has established a valuation allowance for the full amount of the deferred tax assets as management does not currently believe that it is more likely than not that these assets will be recovered in the foreseeable future. To the extent not utilized, the net operating loss carry-forwards as of December 31, 2011 will expire in 2031.

NOTE 11 - SHAREHOLDERS' EQUITY

As of December 31, 2011, the Company had 100,000,000 shares of common stock and 10,000,000 shares of preferred stock authorized, of which 17,436,825 shares of common stock were issued and outstanding. No preferred shares were issued or outstanding. Preferred shares may be issued in such series as Preferred as determined by the Board of Directors. No lock-up or restricted shares were outstanding as of December 31, 2011.

Effective October 19, 2011, the Company completed a four-for-one reverse stock split on its common shares. All references to common stock, restricted stock, stock warrants, and common stock prices have been adjusted to reflect the effects of the reverse stock split.

In December 2011, the Company provided the 8% convertible debenture holders an inducement to convert their conversion price from $9.40 to $4.25. An inducement expense of $2.8 million was recognized in 2011. This transaction also increased additional paid-in capital by $2.8 million. This reduction in conversion price also increased potential dilutive shares outstanding as of December 31, 2011 by 1,082,854 shares from 893,617 to 1,926,471 shares reserved for possible conversion.

In connection with this inducement, the Company entered into an amendment to our 8% senior secured convertible debentures whereby, in addition to the inducement, the mortgage on certain of the Company's oil and gas leases was released and in substitution, we granted a lien on certain replacement oil and gas leases in Nebraska and Wyoming. As partial consideration for the substitution of this collateral, the amendment also provides the holders of the debentures with the first right of refusal to purchase up to 15% of any common stock, preferred stock or convertible debt offering by Recovery through December 31, 2012 at the offering price.

During the year ending December 31, 2011, the Company issued 2,983,233 shares of common stock. The stock issuances were comprised of 2,983,233 shares issued for acquisitions valued at $10,896,071, 10,000 shares issued for services valued at $82,000, 238,824 shares issued as restricted stock grants to employees valued at $6,161,111, 78,972 shares is for interest expense on the convertible notes payable valued at $559,860, 375,333 shares issued in connection with warrant exercises for $2,903,794 of cash.

In addition to the shares of common stock issued during the period, the Company issued convertible notes payable with a face value of $8.4 million. Based upon the current conversion price of $4.25 per share, these notes would convert into 1,976,471 shares of common stock. The conversion price is subject to other adjustments (See Note 7).

During the year ended December 31, 2010, the Company issued 11,749,467 shares of common stock. The stock issuances were comprised of 2,929,167 shares issued for acquisitions valued at $15,787,500, 502,216 shares issued for services valued at $2,256,239, 1,250,000 shares issued in connection with the loan agreements valued at $5,250,000, 2,235,797 shares issued as restricted stock grants to employees valued at $10,283,622, and 3,978,788 shares issued for $20,046,733 of cash.

During the year ended December 31, 2010, the Company issued common shares for cash. Included in these shares was a private placement of 3,975,300 units at $1.50 per unit, which included one share of common stock and one common stock purchase warrant. The warrants are exercisable at $1.50 per share through May 23, 2015. Warrants of 853,500 were subsequently exercised during 2010 for $5,121,000 of cash. In connection with the exercise, the Company granted a new warrant for each warrant exercised. The new warrants have an exercise price of $8.80 per share, which was slightly greater than the concurrent market price of the Company's common stock, and expire on September 29, 2015. The value of the new warrants, calculated at $2,953,450 using the Black Scholes method, was expensed as a warrant modification and included in general and administrative expenses.

Temporary Equity

As part of the reverse merger in 2009, 5,313 shares of common stock were issued and outstanding under a lock-up agreement that has terms which may result in the Company reacquiring the shares due to circumstances outside of the Company's control and therefore the shares are preferential to common shares. The 5,313 shares, which were valued at $172,516, covered by the lock-up agreement were treated as temporary equity and reported separately from other shareholders' equity. The lock-up period for 2,658 shares ended on September 21, 2010, with the other lock-up period ending on March 21, 2011. As a result, on March 21, 2011, the final 2,658 shares covered under the lock-up agreement were moved to permanent on equity.

Warrants

During 2010, the Company issued common shares for cash. Included in these shares was a private placement of 15,901,200 units at $1.50 per unit, which included one share of common stock and one common stock purchase warrant. The warrants are exercisable at $1.50 per share through May 23, 2015. 3,414,000 of these warrants were subsequently exercised during 2010 for $5,121,000 of cash. In connection with the exercise, the Company granted a new warrant for each warrant exercised. The new warrants have an exercise price of $2.20 per share, which was slightly greater than the concurrent market price of the Company's common stock, and expire on September 29, 2015. The value of the new warrants, calculated at $2,953,450 using the Black Scholes method, was expensed as a warrant modification and included in general and administrative expenses

On January 1, 2011, the Company issued 250,000 warrants with an exercise price of $6.00 per share to Hexagon which was valued at approximately $1,600,000 (See Note7).

A summary of warrant activity for the years ended December 31, 2011 and December 31, 2010 is presented below:

	Warrants (1)	**Weighted-Average Exercise Price (1)**
Outstanding at December 31, 2009	187,500	$ 14.00
Granted	6,430,233	6.68
Exercised, forfeited, or expired	(853,500)	6.00
Outstanding at December 31, 2010	5,764,233	7.04
Granted	250,000	6.00
Exercised, forfeited, or expired	(375,333)	6.16
Outstanding at December 31, 2011	5,638,900	$ 6.33

(1) On October 17, 2011, the Company performed a 4:1 reverse stock split. The values shown are reflecting the reverse stock split.

The aggregate intrinsic value of warrants was approximately $0 and $6,687,000 based on the Company's closing common stock price of $5.20 and $8.20 as of December 31, 2011 and December 31, 2010, respectively, and the weighted average remaining contract life was 3.68 years and 4.15 years.

Assumptions used in estimating the fair value of the warrants issued for the periods indicated are presented below:

	For the years ended December 31, 2011	2010
Weighted-average volatility	97%	80%
Expected dividends	0.00%	0.00%
Expected term (in years)	3 – 5	3 – 5
Risk-free rate	2.02%	1.49%

The Company has not adopted a stock incentive plan for its management team. Members of the board of directors and the management team are periodically awarded restricted stock grants.

NOTE 12 - SHARE BASED COMPENSATION

The costs of employee services received in exchange for an award of equity instruments are based on the grant-date fair value of the award, recognized over the period during which an employee is required to provide services in exchange for such award.

During the year ended December 31, 2011, the Company granted 238,750 shares of restricted common stock to employees of which 207,016, vest during the year ended December 31, 2011. The Company will vest restricted stock of 192,000, 120,000, and 2,500 for the years ending December 31, 2012, 2013, and 2014, respectively. The fair value of these share grants was calculated to be approximately $4,370,808.

The Company recognized stock compensation expense of approximately $6,161,000, $917,000 and $2,714,000 for the years ended December 31, 2011, 2010 and 2009, respectively. During the year ended December 31, 2011, the Company had a one-time charge of $3,551,000 for stock compensation expense with the grant of 481,250 shares included in the separation agreement of the former chief financial officer, which was accounted for as a cancellation of an award and issuance of a new award.

A summary of restricted stock grant activity for the year ended December 31, 2011 is presented below

		Shares (1)
Outstanding at March 6,2009	$	-
Granted		371,050
Vested		-
Outstanding at December 31, 2009		371,050
Granted		1,864,747
Vested		-
Outstanding at December 31, 2010		2,235,797
Granted		932,500
Vested		(828,062)
Outstanding at December 31, 2011	$	2,340,235

(1) On October 17, 2011, the Company affected a 4:1 reverse stock split. The values shown are reflecting the reverse stock split.

The Company will recognize $1,066,000, $366,615 and $12,478 for the years ending December 31, 2012, 2013, and 2014, respectively.

NOTE 13 – DRILLING RIGS

In May 2009, two drilling rigs were contributed to the Company for a note of $3,250,000. These rigs were recorded at estimated fair value as this was lower than their predecessor cost basis. The note holder subsequently converted the note for 2,100,000 shares of common stock (Note 3). These rigs required certain capital improvements prior to their ability to be functional in operations.

In 2009, management determined that future drilling operations were not part of their strategic plans. Management estimated the net realizable value to be $500,000; therefore, an impairment of $2,750,000 was recorded for the period ending December 31, 2009.

In May 2010, the Company entered into a purchase and sale agreement for the rigs. The Company sold the rigs for $700,000 under which the Company received $100,000 in cash and the balance in a five-year secured note. The acquirer defaulted on the note and the Company is now pursuing the remedies afforded to it under the note and security agreement. The Company believes it is in a first lien position on the underlying collateral, however, in 2010 the Company elected to fully reserve the $400,000 note receivable as the ability to recover the amount and the value of the underlying collateral was uncertain.

NOTE 14: SUBSEQUENT EVENTS

On March 19, 2012, the Company entered into agreements with its existing convertible debenture holders to extend the amount of its debenture debt by up to an additional $5.0 million. Proceeds resulting from the increase in the debentures will be used principally for the development of certain of the Company's proved undeveloped properties, and other undeveloped leases currently targeted by the Company for exploration, as well as for other working capital purposes. Any new producing properties that are developed from the proceeds of this offering will be pledged as collateral to secure the expanded debt.

The initial closing related to these agreements will be in the amount of $1.5 million and is expected to occur prior to March 23, 2012. On or before September 15, 2012, convertible debenture holders may elect to purchase up to an additional $3.5 million in additional debentures. All terms of the expansion convertible debentures are substantively identical to the existing convertible debentures (see Note 7).

NOTE 15- SUPPLEMENTAL OIL AND GAS RESERVE INFORMATION (UNAUDITED)

The following table sets forth information for the years ended December 31, 2011, 2010 and 2009 with respect to changes in the Company's proved (i.e. proved developed and undeveloped) reserves:

	Crude Oil (Bbls)	Natural Gas (Mcf)
December 31, 2009	-	-
Purchase of reserves	643,955	-
Revisions of previous estimates	123,679	-
Extensions and discoveries	58,463	323,493
Sale of reserves	-	-
Production	(133,709)	(14,914)
December 31, 2010	692,388	308,579
Purchase of reserves	-	-
Revisions of previous estimates	(268,718)	(44,919)
Extensions, discoveries	266,000	-
Sale of reserves		
Production	(81,433)	(115,583)
December 31, 2011	608,237	148,077
Proved Developed Reserves, included above:		
Balance, December 31, 2009	-	-
Balance, December 31, 2010	277,669	308,579
Balance, December 31, 2011	215,693	148,077
Proved Undeveloped Reserves, included above:		
Balance, December 31, 2009	-	-
Balance, December 31, 2010	414,719	-
Balance, December 31, 2011	392,545	-

The Company did not have any reserves as of December 31, 2009.

As of December 31, 2011 and December 31, 2010, we had estimated proved reserves of 608,237 and 692,388 barrels of oil, respectively and 24,680 and 308,579 thousand cubic feet ("MCF") of natural gas, respectively. Our reserves are comprised of 96% and 93% crude oil and 4% and 7% natural gas on an energy equivalent basis.

The following values for the December 31, 2011 and December 31, 2010 oil and gas reserves are based on the 12 month arithmetic average first of month price January through December 31 natural gas price of $3.96 and $4.39 per MMBtu (NYMEX price) and crude oil price of $88.16 and $77.78 per barrel (West Texas Intermediate price). All prices are then further adjusted for transportation, quality and basis differentials.

During the years ended December 31, 2010, the Company completed multiple acquisitions which included proved reserves associated with producing properties. Included in the Company's December 31, 2010 proved reserves classified as 'Purchase of reserves' in the table above, are $3,760,000 and 643,955 barrels of crude oil attributable to the acquisitions.

The following summary sets forth the Company's future net cash flows relating to proved oil and gas:

	For the Year Ended December 31, (in thousands)		
	2011	**2010**	**2009 (1)**
Future oil and gas sales	$ 55,295	$ 51,816	$ -
Future production costs	(16,579)	(11,614)	-
Future development costs	(8,481)	(8,063)	-
Future income tax expense (2)	-	-	-
Future net cash flows	30,235	32,139	-
10% annual discount	(10,221)	(8,544)	-
Standardized measure of discounted future net cash flows	$ 20,014	$ 23,595	$ -

(1) Prior to January 2010, the Company did not own any oil and gas assets.

(2) Our calculations of the standardized measure of discounted future net cash flows include the effect of estimated future income tax expenses for all years reported. We expect that all of our Net Operating Loss' ("NOL") will be realized within future carry forward periods. All of the Company's operations, and resulting NOLs, are attributable to our oil and gas assets. There were no taxes in any year as the tax basis and NOL's exceeded the future net revenue.

The principle sources of change in the standardized measure of discounted future net cash flows are:

	2011	2010	2009 (1)
Balance at beginning of period	$ 23,595	$ -	$ -
Sales of oil and gas, net	(5,342)	(7,655)	-
Net change in prices and production costs	8,006	3,084	-
Net change in future development costs	-	(4,563)	-
Extensions and discoveries	5,883	5,067	-
Acquisition of reserves		18,967	-
Sale of reserves		-	-
Revisions of previous quantity estimates	(14,804)	5,245	-
Previously estimated development costs incurred		-	-
Net change in income taxes		-	-
Accretion of discount	2,360	2,043	-
Other	316	1,407	-
Balance at end of period	$ 20,014	$ 23,595	$ -

Revisions in 2011 of previous quantity estimates relate principally to the exclusion of certain proven undeveloped well locations that were included in the reserve estimates dated December 31, 2010.

A variety of methodologies are used to determine our proved reserve estimates. The principal methodologies employed are reservoir simulation, decline curve analysis, volumetric, material balance, advance production type curve matching, petro-physics/log analysis and analogy. Some combination of these methods is used to determine reserve estimates in substantially all of our fields.

NOTE 16- QUARTERLY RESULTS (UNAUDITED)

The following tables contain selected unaudited statement of operations information for each quarter of 2011 and 2010. The Company believes that the following information reflects all normal recurring adjustments necessary for a fair presentation of the information for the periods presented. The operating results for any quarter are not necessarily indicative of results for any future period.

	Year Ended December 31, 2011			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
Revenues	$ 1,944,454	$ 2,630,933	$ 2,811,429	$ 1,273,675
Income (loss) from operations	(6,297,854)	(939,330)	(4,069,541)	(2,052,133)
Net earnings (loss)	(7,295,537)	(3,027,618)	(4,762,881)	(3,743,187)
Net earnings per common share:				
Basic and diluted	$ (0.47)	$ (0.19)	$ (0.30)	$ (0.25)
Weighted average shares outstanding				
Basic and diluted	15,543,758	15,775,135	15,635,346	14,778,206

	Year Ended December 31, 2010			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
Revenues	$ 1,519,702	$ 2,552,790	$ 5,194,849	$ 490,351
Income (loss) from operations	(4,191,728)	(5,900,630)	(792,880)	(2,242,252)
Net earnings (loss)	(6,230,293)	(7,491,246)	(3,196,779)	(2,820,715)
Net earnings per common share:				
Basic and diluted	$ (1.47)	$ (2.53)	$ (1.99)	$ (1.04)
Weighted average shares outstanding				
Basic and diluted	9,167,803	2,962,882	6,362,922	2,927,759