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

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended August 31, 2012

OR

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

For the transition period from ________________________ to ________________________

Commission file number: 001-35245

SYNERGY RESOURCES CORPORATION

(Exact name of registrant as specified in its charter)

COLORADO	**20-2835920**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
20203 Highway 60, Platteville, CO	**80651**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (970) 737-1073

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock	**NYSE MKT**

Securities registered pursuant to Section 12(g) of the Act:

____

(Title of class)

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 Section 15(d) of the Act. Yes ☐ No ☒

Note – Checking the box above will not relieve any registrant required to file reports pursuant to Section 13 or 15(d) of the Exchange Act from their obligations under those Sections.

Persons who respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB control number.

Indicate by check mark whether the registrant (1) has filed all reports to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the 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 weather the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulations S-T (232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such filing). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of 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. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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

The aggregate market value of the voting stock held by non-affiliates of the registrant, based upon the closing sale price of the registrant's common stock on February 29, 2012, was approximately $148,400,000. Shares of the registrant's common stock held by each officer and director and each person known to the registrant to own 10% or more of the outstanding voting power of the registrant have been excluded in that such persons may be deemed to be affiliates. This determination of affiliate status is not a determination for other purposes.

As of November 1, 2012, the Registrant had 51,676,844 issued and outstanding shares of common stock.

PART I

Cautionary Statement Concerning Forward-Looking Statements

This report contains "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. These statements are subject to risks and uncertainties and are based on the beliefs and assumptions of management and information currently available to management. The use of words such as "believes", "expects", "anticipates", "intends", "plans", "estimates", "should", "likely" or similar expressions, indicates a forward-looking statement.

The identification in this report of factors that may affect our future performance and the accuracy of forward-looking statements is meant to be illustrative and by no means exhaustive. All forward-looking statements should be evaluated with the understanding of their inherent uncertainty.

Factors that could cause our actual results to differ materially from those expressed or implied by forward-looking statements include, but are not limited to:

- The success of our exploration and development efforts;
- The price of oil and gas;
- The worldwide economic situation;
- Any change in interest rates or inflation;
- The willingness and ability of third parties to honor their contractual commitments;
- Our ability to raise additional capital, as it may be affected by current conditions in the stock market and competition in the oil and gas industry for risk capital;
- Our capital costs, as they may be affected by delays or cost overruns;
- Our costs of production;
- Environmental and other regulations, as the same presently exist or may later be amended;
- Our ability to identify, finance and integrate any future acquisitions; and
- The volatility of our stock price.

ITEM 1. BUSINESS

Overview

We are an oil and gas operator in Colorado and are focused on the acquisition, development, exploitation, exploration and production of oil and natural gas properties primarily located in the Wattenberg Field in the Denver-Julesburg Basin ("D-J Basin") in northeast Colorado. We serve as the operator for most of our wells and focus our efforts on those prospects in which we have a significant net revenue interest. As of October 15, 2012, we had 226,948 gross and 191,168 net acres under lease, substantially all of which are located in the D-J Basin. Of this acreage, 8,526 gross acres are held by production.

We commenced active operations in the D-J Basin in 2008. Between September 1, 2008 and August 31, 2012, we drilled, participated or otherwise acquired an interest in 209 gross (158 net) oil and gas wells. As of August 31, 2012, 191 gross (147 net) wells were producing oil and gas and 18 wells were in various stages of completion. There have been no dry holes. We are the operator of 156 wells and participated with other operators in 53 wells.

At August 31, 2012, our estimated net proved oil and gas reserves, as prepared by our independent reserve engineering firm, Ryder Scott Company, L.P., were 5.1 MMBbls of oil and condensate and 33.4 Bcf of natural gas.

Business Strategy

Our primary objective is to enhance shareholder value by increasing our net asset value, net reserves and cash flow through acquisitions, development, exploitation, exploration and divestiture of oil and gas properties. We intend to follow a balanced risk strategy by allocating capital expenditures in a combination of lower risk development and exploitation activities and higher potential exploration prospects. Key elements of our business strategy include the following:

- *Concentrate on our existing core area in and around the D-J Basin, where we have significant operating experience.* All of our current wells are located within the D-J Basin and our undeveloped acreage is located either in or adjacent to the D-J Basin. Focusing our operations in this area leverages our management, technical and operational experience in the basin.

- *Develop and exploit existing oil and natural gas properties.* Since inception our principal growth strategy has been to develop and exploit our acquired and discovered properties to add proved reserves. In the Wattenberg Field, we target three formations, the Niobrara, the Codell, and the J-Sand. We selectively target the zones most likely to yield the greatest return on investment, and leave certain zones "behind pipe" for future extraction. Our future plans include both vertical and horizontal wellbores into the target zones. As of October 15, 2012, in the Wattenberg Field, we have identified over 400 development and extension drilling locations, 200 behind pipe untapped reservoirs, and over 50 recompletion/work-over projects on our existing properties and wells. We consider the Wattenberg Field to be relatively low-risk because information gained from the large number of existing wells can be applied to potential wells. There is enough similarity between wells in the Field that the exploitation process is generally repeatable.

- *Complete selective acquisitions.* We seek to acquire undeveloped and producing oil and gas properties, primarily in the D-J Basin and certain adjacent areas. We will seek acquisitions of undeveloped and producing properties that will provide us with opportunities for reserve additions and increased cash flow through production enhancement and additional development and exploratory prospect generation opportunities.

- *Retain control over the operation of a substantial portion of our production.* As operator on a majority of our wells and undeveloped acreage, we control the timing and selection of new wells to be drilled or existing wells to be recompleted. This allows us to modify our capital spending as our financial resources allow and market conditions support.

- *Maintain financial flexibility while focusing on controlling the costs of our operations.* We intend to finance our operations through a mixture of debt and equity capital as market conditions allow. Our management has historically been a low cost operator in the D-J Basin and we continue to focus on operating efficiencies and cost reductions.

- *Use the latest technology to maximize returns.* Drilling horizontal wells is expected to significantly increase our future production. During 2012, we participated in five horizontal wells with major operators. Initial evaluation of the new wells has been favorable. For 2013, we have budgeted additional horizontal well participations with other operators, along with plans to drill four horizontal wells in which we will own a 100% working interest. We have identified an additional 160 potential horizontal wells in the Niobrara and Codell formations on existing Wattenberg acreage and over 200 potential horizontal well locations in the Greenhorn and Niobrara formations in the Northern D-J Basin acreage. Of these locations, 12 are in the drilling permit process.

Competitive Strengths

We believe that we are positioned to successfully execute our business strategy because of the following competitive strengths:

- *Management experience.* Our key management team possesses an average of thirty years of experience in the oil and gas industry, primarily within the D-J Basin. Members of our management team have drilled, participated in drilling, and/or operated over 350 wells in the D-J Basin.

- *Balanced oil and natural gas reserves and production.* At August 31, 2012, approximately 48% of our estimated proved reserves were oil and condensate and 52% were natural gas and liquids, measured upon a BTU equivalent basis. We believe this balanced commodity mix will provide diversification of sources of cash flow and will lessen the risk of significant and sudden decreases in revenue from short-term commodity price movements.

- *Ability to recomplete D-J Basin wells numerous times throughout the life of a well.* We have experience with and knowledge of D-J Basin wells that have been recompleted up to three times since initial drilling. This provides us with numerous high return recompletion investment opportunities on our current and future wells and the ability to manage the production through the life of a well.

- *Insider ownership.* At October 15, 2012 our directors and executive officers beneficially owned approximately 24% of our outstanding shares of common stock, providing a strong alignment of interest between management, the board of directors and our outside shareholders.

Recent Developments

We expanded our business during the fiscal year ended August 31, 2012. We increased our producing wells, our reserves, and our undeveloped acreage. Significant developments are described below.

We increased our proved reserve quantities by 140% during the year. The August 31, 2012, reserve report indicated that we had estimated proved reserves of 5.1 million barrels of oil and 33.4 billion cubic feet of gas. The estimated present value before tax (discounted at 10%) is $149 million.

In late summer of 2011, we commenced drilling operations with a rig under contract to us from Ensign United States Drilling, Inc. There were six wells in progress on September 1, 2011, all of which were completed during the year. Between September 1, 2011, and August 31, 2012, Ensign drilled 51 wells for us, 41 of which reached productive status by August 31, 2012. As of August 31, 2012, completion activities were underway on 10 wells, all which have since reached productive status. In addition, we participated in 13 wells drilled by other operators, five of which reached productive status prior to August 31, 2012.

Since August 31, 2012, we continue to drill wells with Ensign and expect approximately 25 wells to be drilled during the first quarter of 2013.

As a result of increasingly successful results of horizontal drilling in the Wattenberg, we entered the horizontal market with limited involvement by participating in five horizontal wells in 2012, three of which contributed revenue by fiscal year end. All wells drilled prior to 2012 were relatively low-risk vertical or directional wells.

During the year, we closed on the acquisition of interests in mineral leases in Weld, Morgan and Larimer Counties, Colorado and also purchased from some minority partners their working interests in existing wells. The interests were acquired with $2.3 million in cash and 261,482 shares of our common stock. Initial exploration activities on the prospect will focus on the potential for horizontal drilling in the Niobrara and Greenhorn formations.

We improved our access to capital resources by negotiating increases to our revolving line of credit with Community Banks of Colorado. Shortly after year-end, we increased the commitment amount from $20 million to $30 million.

During December 2011, we completed the sale of 14.6 million shares of our common stock at $2.75 per share for net proceeds totaling approximately $37.4 million after deduction of discounts, commissions and expenses. The public offering of additional shares of our common stock was underwritten by Northland Capital Markets, C. K. Cooper & Company, and GVC Capital LLC.

During the year, we recognized a one-time tax benefit of $4,911,000 for the estimated value of the net operating loss carry-forward that we accumulated from inception to August 31, 2011.

Well and Production Data

During the periods presented below, we drilled or participated in the drilling of a number of wells that reached productive status in each respective fiscal year. We did not drill any exploratory wells nor did we drill any dry holes during these years. The following table excludes wells that are in the drilling or completion phase and had not reached the point at which they are capable of producing oil and gas.

	Years Ended August 31,					
	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive:						
Oil	52	37.9	39	21.4	22	13.4
Gas	—	—	—	—	—	—
Nonproductive	—	—	—	—	—	—

Excluded from the table above are wells that had not reached productive status as of August 31, 2012. As such, 1 gross (1 net) well in the drilling phase and 17 gross (10.2 net) wells in the completion phase were not included in the above well counts. These wells are all located in the Wattenberg Field of the D-J Basin.

The following table shows our net production of oil and gas, average sales prices and average production costs for the periods presented:

	Years Ended August 31,		
	2012	2011	2010
Production:			
Oil (Bbls)	235,691	89,917	21,080
Gas (Mcf)	1,109,057	450,831	141,154
Average sales price:			
Oil ($/Bbl[1])	$ 87.59	$ 83.07	$ 68.38
Gas ($/Mcf[2])	$ 3.90	$ 5.12	$ 5.08
Average production cost per BOE[3]	$ 2.73	$ 2.13	$ 1.94

1 "Bbl" refers to one stock tank barrel, or 42 U.S. gallons liquid volume in reference to crude oil or other liquid hydrocarbons.

2 "Mcf" refers to one thousand cubic feet of natural gas.

3 "BOE" refers to barrel of oil equivalent, which combines Bbls of oil and Mcf of gas by converting each six Mcf of gas to one Bbl of oil.

Production costs are substantially similar among our wells as all of our wells are in the Wattenberg Field and employ the same methods of recovery. Production costs generally include pumping fees, maintenance, repairs, labor, utilities and administrative overhead. Taxes on production, including ad valorem and severance taxes, are not included in production costs.

We are not obligated to provide a fixed and determined quantity of oil or gas to any third party in the future. During the last three fiscal years, we have not had, nor do we now have, any long-term supply or similar agreement with any government or governmental authority.

Oil and Gas Properties

We evaluate undeveloped oil and gas prospects and participate in drilling activities on those prospects, which, in the opinion of our management, are favorable for the production of oil or gas. If, through our review, a geographical area indicates geological and economic potential, we will attempt to acquire leases or other interests in the area. We may then attempt to sell portions of our leasehold interests in a prospect to third parties, thus sharing the risks and rewards of the exploration and development of the prospect with the other owners. One or more wells may be drilled on a prospect, and if the results indicate the presence of sufficient oil and gas reserves, additional wells may be drilled on the prospect.

We may also:

- acquire a working interest in one or more prospects from others and participate with the other working interest owners in drilling, and if warranted, completing oil or gas wells on a prospect, or

- purchase producing oil or gas properties.

Our activities are primarily dependent upon available financing.

Title to properties we acquire may be subject to royalty, overriding royalty, carried, net profits, working and other similar interests and contractual arrangements customary in the oil and gas industry, and subject to liens for current taxes not yet due and to other encumbrances. As is customary in the industry, in the case of undeveloped properties little investigation of record title will be made at the time of acquisition (other than a preliminary review of local records). However, drilling title opinions may be obtained before commencement of drilling operations.

The following table shows, as of October 15, 2012, by state, our producing wells, developed acreage, and undeveloped acreage, excluding service (injection and disposal) wells:

	Productive Wells		Developed Acreage		Undeveloped Acreage [1]	
State	Gross	Net	Gross	Net	Gross	Net
Colorado	197	159	7,688	6,268	103,307	69,618
Nebraska	—	—	—	—	114,810	114,810
Wyoming	—	—	—	—	1,143	472
Total	197	159	7,688	6,268	219,260	184,900

[1] Undeveloped acreage includes leasehold interests on which wells have not been drilled or completed to the point that would permit the production of commercial quantities of natural gas and oil regardless of whether the leasehold interest is classified as containing proved undeveloped reserves.

The following table shows, as of October 15, 2012, the status of our gross acreage:

State	Held by Production	Not Held by Production
Colorado	8,526	102,469
Nebraska	—	114,810
Wyoming	—	1,143
Total	8,526	218,422

Acres that are Held by Production remain in force so long as oil or gas is produced from the well on the particular lease. Leased acres which are not Held By Production require annual rental payments to maintain the lease until the first to occur of the following: the expiration of the lease or the time oil or gas is produced from one or more wells drilled on the leased acreage. At the time oil or gas is produced from wells drilled on the leased acreage, the lease is considered to be Held by Production.

The following table shows the years our leases, which are not Held By Production, will expire, unless a productive oil or gas well is drilled on the lease.

Leased Acres	Expiration of Lease
22,231	2013
14,669	2014
3,752	2015
177,769	After 2015

The overriding royalty interests that we own are not material to our business.

Proved Reserve Estimates

Ryder Scott Company, L.P. ("Ryder Scott") prepared the estimates of our proved reserves, future productions and income attributable to our leasehold interests for the year ended August 31, 2012. Ryder Scott is an independent petroleum engineering firm that has been providing petroleum consulting services worldwide for over seventy years. The estimates of drilled reserves, future production and income attributable to certain leasehold and royalty interests are based on technical analysis conducted by teams of geoscientists and engineers employed at Ryder Scott. The office of Ryder Scott that prepared our reserves estimates is registered in the state of Texas (License #F-1580). Ryder Scott prepared our reserve estimate based upon a review of property interests being appraised, historical production, lease operating expenses and price differentials for our wells. Additionally, authorizations for expenditure, geological and geophysical data, and other engineering data that complies with SEC guidelines are among that which we provide to Ryder Scott engineers for consideration in estimating our underground accumulations of crude oil and natural gas.

The report of Ryder Scott dated November 2, 2012, which contains further discussions of the reserve estimates and evaluations prepared by Ryder Scott as well as the qualifications of Ryder Scott's technical personnel responsible for overseeing such estimates and evaluations, is attached as Exhibit 99 to this report.

Ed Holloway, our President and Chief Executive Officer, oversaw the preparation of the reserve estimates by Ryder Scott to ensure accuracy and completeness of the data prior to and after submission. Mr. Holloway has over thirty years of experience in oil and gas exploration and development.

Our proved reserves include only those amounts which we reasonably expect to recover in the future from known oil and gas reservoirs under existing economic and operating conditions, at current prices and costs, under existing regulatory practices and with existing technology. Accordingly, any changes in prices, operating and development costs, regulations, technology or other factors could significantly increase or decrease estimates of proved reserves.

Estimates of volumes of proved reserves at year end are presented in barrels (Bbls) for oil and for, natural gas, in thousands of cubic feet (Mcf) at the official temperature and pressure bases of the areas in which the gas reserves are located.

The proved reserves attributable to producing wells and/or reservoirs were estimated by performance methods. These performance methods include decline curve analysis, which utilized extrapolations of historical production and pressure data available through August 31, 2012, in those cases where this data was considered to be definitive. The data used in this analysis was obtained from public data sources and were considered sufficient for calculating producing reserves.

The proved non-producing and undeveloped reserves were estimated by the analogy method. The analogy method uses pertinent well data obtained from public data sources that were available through August 2012.

Below are estimates of our net proved reserves at August 31, 2012, all of which are located in Colorado:

	Oil (Bbls)	Gas (Mcf)
Proved:		
Producing	1,160,464	7,243,960
Nonproducing	1,663,140	10,136,846
Undeveloped	2,262,207	16,065,168
Total	5,085,811	33,445,974

Below are estimates of our present value of estimated future net revenues from such reserves based upon the standardized measure of discounted future net cash flows relating to proved oil and gas reserves in accordance with the provisions of Accounting Standards Codification Topic 932, Extractive Activities – Oil and Gas. The standardized measure of discounted future net cash flows is determined by using estimated quantities of proved reserves and the periods in which they are expected to be developed and produced based on period-end economic conditions. The estimated future production is based upon benchmark prices that reflect the unweighted arithmetic average of the first-day-of-the-month price for oil and gas during the years ended August 31, 2012, 2011 and 2010. The resulting estimated future cash inflows are then reduced by estimated future costs to develop and produce reserves based on period-end cost levels. No deduction has been made for depletion, depreciation or for indirect costs, such as general corporate overhead. Present values were computed by discounting future net revenues by 10% per year.

As of August 31, 2012, 2011 and 2010, our standardized oil and gas measurements were as follows:

	Proved – August 31, 2012			
	Developed			Total
	Producing	Nonproducing	Undeveloped	Proved
Future gross revenue	$ 120,801,855	$ 173,143,585	$ 243,516,439	$ 537,461,879
Deductions	(21,098,920)	(48,535,722)	(116,798,472)	(186,433,114)
Future net cash flow	99,702,935	124,607,863	126,717,967	351,028,765
Discounted future net cash flow (pre-tax)	$ 57,797,059	$ 56,196,448	$ 34,889,944	$ 148,883,451
Standardized measure of discounted future net cash flows (after tax)				$ 102,504,795

	Proved – August 31, 2011			
	Developed			Total
	Producing	Nonproducing	Undeveloped	Proved
Future gross revenue	$ 71,027,480	$ 18,819,100	$ 145,392,300	$ 235,238,880
Deductions	(14,298,253)	(5,647,380)	(61,736,015)	(81,681,648)
Future net cash flow	56,729,227	13,171,720	83,656,285	153,557,232
Discounted future net cash flow (pre-tax)	$ 33,946,592	$ 6,995,878	$ 30,815,373	$ 71,757,843
Standardized measure of discounted future net cash flows (after tax)				$ 57,550,414

	Proved – August 31, 2010			
	Developed			Total
	Producing	Nonproducing	Undeveloped	Proved
Future gross revenue	$ 12,323,383	$ 24,126,662	$ 28,220,857	$ 64,670,902
Deductions	(2,955,552)	(8,942,579)	(20,319,150)	(32,217,281)
Future net cash flow	9,367,831	15,184,083	7,901,707	32,453,621
Discounted future net cash flow (pre-tax)	$ 6,120,468	$ 8,704,767	$ 1,732,491	$ 16,557,726
Standardized measure of discounted future net cash flows (after tax)				$ 13,022,397

For standardized oil and gas measurement purposes, our drilling, acquisition, and participation activities during the year ended August 31, 2012, generated increases in projected future gross revenue from proved reserves of $302,222,999 and future net cash flow of $197,471,533 from August 31, 2011. During that same period, when applying a 10% discount rate to our future net cash flows, our discounted future net cash flow from proved reserves increased by $77,125,608. Increases in our standardized oil and gas measures were the result of our expenditures during the year ended August 31, 2012, of approximately $33 million for the development of oil and gas properties and acquisitions of in place reserves, which directly related to proved oil and gas reserves.

For standardized oil and gas measurement purposes, our drilling, acquisition, and participation activities during the year ended August 31, 2011, generated increases in projected future gross revenue from proved reserves of $170,567,978 and future net cash flow of $121,103,611 from August 31, 2010. During that same period, when applying a 10% discount rate to our future net cash flows, our discounted future net cash flow from proved reserves increased by $55,200,117. Increases in our standardized oil and gas measures were the result of our expenditures during the year ended August 31, 2011, of approximately $22 million for the development of oil and gas properties and acquisitions of in place reserves, which directly related to proved oil and gas reserves.

In general, the volume of production from our oil and gas properties declines as reserves are depleted. Except to the extent we acquire additional properties containing proved reserves or conduct successful exploration and development activities, or both, our proved reserves will decline as reserves are produced. Accordingly, volumes generated from our future activities are highly dependent upon the level of success in acquiring or finding additional reserves and the costs incurred in doing so.

Government Regulation

Various state and federal agencies regulate the production and sale of oil and natural gas. All states in which we plan to operate impose restrictions on the drilling, production, transportation and sale of oil and natural gas.

The Colorado Oil and Gas Conservation Commission (“COGCC”) is the primary regulator of exploration and production of oil and gas resources in the area in which we operate. Via the permitting and inspection process, COGCC regulates oil and gas operators and, among other criteria, enforces specifications regarding the mechanical integrity of wells as well as the prevention and mitigation of adverse environmental impacts.

The Federal Energy Regulatory Commission (“FERC”) regulates the interstate transportation and the sale in interstate commerce for resale of natural gas. FERC’s jurisdiction over interstate natural gas sales has been substantially modified by the Natural Gas Policy Act under which FERC continued to regulate the maximum selling prices of certain categories of gas sold in "first sales" in interstate and intrastate commerce.

FERC has pursued policy initiatives that have affected natural gas marketing. Most notable are (1) the large-scale divestiture of interstate pipeline-owned gas gathering facilities to affiliated or non-affiliated companies; (2) further development of rules governing the relationship of the pipelines with their marketing affiliates; (3) the publication of standards relating to the use of electronic bulletin boards and electronic data exchange by the pipelines to make available transportation information on a timely basis and to enable transactions to occur on a purely electronic basis; (4) further review of the role of the secondary market for released pipeline capacity and its relationship to open access service in the primary market; and (5) development of policy and promulgation of orders pertaining to its authorization of market-based rates (rather than traditional cost-of-service based rates) for transportation or transportation-related services upon the pipeline's demonstration of lack of market control in the relevant service market. We do not know what effect FERC's other activities will have on the access to markets, the fostering of competition and the cost of doing business.

Our sales of oil and natural gas liquids will not be regulated and will be at market prices. The price received from the sale of these products will be affected by the cost of transporting the products to market. Much of that transportation is through interstate common carrier pipelines.

Federal, state, and local agencies have promulgated extensive rules and regulations applicable to our oil and natural gas exploration, production and related operations. Most states require permits for drilling operations, drilling bonds and the filing of reports concerning operations and impose other requirements relating to the exploration of oil and gas. Many states also have statutes or regulations addressing conservation matters including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and gas wells and the regulation of spacing, plugging and abandonment of such wells. The statutes and regulations of some states limit the rate at which oil and gas is produced from our properties. The federal and state regulatory burden on the oil and natural gas industry increases our cost of doing business and affects its profitability. Because these rules and regulations are amended or reinterpreted frequently, we are unable to predict the future cost or impact of complying with those laws.

As with the oil and natural gas industry in general, our properties are subject to extensive and changing federal, state and local laws and regulations designed to protect and preserve our natural resources and the environment. The recent trend in environmental legislation and regulation is generally toward stricter standards, and this trend is likely to continue. These laws and regulations often require a permit or other authorization before construction or drilling commences and for certain other activities; limit or prohibit access, seismic acquisition, construction, drilling and other activities on certain lands lying within wilderness and other protected areas; impose substantial liabilities for pollution resulting from our operations; and require the reclamation of certain lands.

The permits required for many of our operations are subject to revocation, modification and renewal by issuing authorities. Governmental authorities have the power to enforce compliance with their regulations, and violations are subject to fines, injunctions or both. In the opinion of our management, we are in substantial compliance with current applicable environmental laws and regulations, and we have no material commitments for capital expenditures to comply with existing environmental requirements. Nevertheless, changes in existing environmental laws and regulations or in their interpretation could have a significant impact on us, as well as the oil and natural gas industry in general.

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA") and comparable state statutes impose strict and joint and several liabilities on owners and operators of certain sites and on persons who disposed of or arranged for the disposal of "hazardous substances" found at such sites. It is not uncommon for the 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. The Resource Conservation and Recovery Act ("RCRA") and comparable state statutes govern the disposal of "solid waste" and "hazardous waste" and authorize imposition of substantial fines and penalties for noncompliance. Although CERCLA currently excludes petroleum from its definition of "hazardous substance," state laws affecting our operations impose clean-up liability relating to petroleum and petroleum related products. In addition, although RCRA classifies certain oil field wastes as "non-hazardous," such exploration and production wastes could be reclassified as hazardous wastes, thereby making such wastes subject to more stringent handling and disposal requirements.

Federal regulations require certain owners or operators of facilities that store or otherwise handle oil, such as us, to prepare and implement spill prevention, control countermeasure and response plans relating to the possible discharge of oil into surface waters. The Oil Pollution Act of 1990 ("OPA") contains numerous requirements relating to the prevention of and response to oil spills into waters of the United States. For onshore and offshore facilities that may affect waters of the United States, the OPA requires an operator to demonstrate financial responsibility. Regulations are currently being developed under federal and state laws concerning oil pollution prevention and other matters that may impose additional regulatory burdens on us. In addition, the Clean Water Act and analogous state laws require permits to be obtained to authorize discharge into surface waters or to construct facilities in wetland areas. The Clean Air Act of 1970 and its subsequent amendments in 1990 and 1997 also impose permit requirements and necessitate certain restrictions on point source emissions of volatile organic carbons (nitrogen oxides and sulfur dioxide) and particulates with respect to certain of our operations. We are required to maintain such permits or meet general permit requirements. The EPA and designated state agencies have in place regulations concerning discharges of storm water runoff and stationary sources of air emissions. These programs require covered facilities to obtain individual permits, participate in a group or seek coverage under an EPA general permit. Most agencies recognize the unique qualities of oil and natural gas exploration and production operations. A number of agencies have adopted regulatory guidance in consideration of the operational limitations on these types of facilities and their potential to emit pollutants. We believe that we will be able to obtain, or be included under, such permits, where necessary, and to make minor modifications to existing facilities and operations that would not have a material effect on us.

The EPA recently amended the Underground Injection Control, or UIC, provisions of the federal Safe Drinking Water Act (the "SDWA") to exclude hydraulic fracturing from the definition of "underground injection." However, the U.S. Senate and House of Representatives are currently considering the Fracturing Responsibility and Awareness of Chemicals Act (the "FRAC Act"), which will amend the SDWA to repeal this exemption. If enacted, the FRAC Act would amend the definition of "underground injection" in the SDWA to encompass hydraulic fracturing activities, which could require hydraulic fracturing operations to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting, and recordkeeping obligations, and meet plugging and abandonment requirements.

The FRAC Act also proposes to require the reporting and public disclosure of chemicals used in the fracturing process, 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. While no federal law is presently in place, some states have enacted laws pertaining to chemical disclosure. In December 2011, the State of Colorado approved regulation requiring parties engaged in hydraulic fracturing to disclose the concentrations of the chemicals used in the process. The regulation went into effect in April 2012 and requires the reporting of additives used.

On December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climatic changes. These findings by the EPA allowed the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act.
Consequently, the EPA proposed two sets of regulations that would require a reduction in emissions of greenhouse gases from motor vehicles and, also, could trigger permit review for greenhouse gas emissions from certain stationary sources. In addition, on October 30, 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2012 for emissions occurring in 2011.

Also, on June 26, 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009 (the "ACESA") which would establish an economy-wide cap-and-trade program to reduce United States emissions of greenhouse gases including carbon dioxide and methane that may contribute to the warming of the Earth's atmosphere and other climatic changes. If it becomes law, ACESA would require a 17% reduction in greenhouse gas emissions from 2005 levels by 2020 and just over an 80% reduction of such emissions by 2050. Under this legislation, the EPA would issue a capped and steadily declining number of tradable emissions allowances to certain major sources of greenhouse gas emissions so that such sources could continue to emit greenhouse gases into the atmosphere. These allowances would be expected to escalate significantly in cost over time. The net effect of ACESA will be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products and natural gas.

Climate change has emerged as an important topic in public policy debate regarding our environment. It is a complex issue, with some scientific research suggesting that rising global temperatures are the result of an increase in greenhouse gases, which may ultimately pose a risk to society and the environment. Products produced by the oil and natural gas exploration and production industry are a source of certain greenhouse gases, namely carbon dioxide and methane, and future restrictions on the combustion of fossil fuels or the venting of natural gas could have a significant impact on our future operations.

Hydraulic Fracturing

We operate in the Wattenberg Field of the D-J Basin, where the rock formations are typically tight and it is a common practice to utilize hydraulic fracturing to allow for or increase hydrocarbon production. Hydraulic fracturing involves the process of forcing a mixture of fluid and white sand into a formation to create pores and fractures, thus creating a passageway for the release of oil and gas. All of our producing wells were hydraulic fractured and we expect to employ the technique extensively in future wells that we drill.

We outsource all hydraulic fracturing services to service providers with significant experience, and whom we deem to be competent and responsible. Our service providers supply all personnel, equipment and materials needed to perform each stimulation, including the mixtures that are injected into our wells. These mixtures primarily consist of water and sand, with nominal amounts of other ingredients that include chemical compounds commonly found in consumer products. This mixture is injected into our wells at pressures of 5,500-6,000 psi at injection rates that that range between 25-55 barrels of mixture per minute. On average, a single stage stimulation will utilize approximately 4,500 barrels of water and 125,000 pounds of sand.

We require our service companies to carry adequate insurance covering incidents that could occur in connection with their activities. Our service providers are responsible for obtaining any regulatory permits necessary for them to perform their services in the respective geographic location. We have not had any incidents, citations or lawsuits relating to any environmental issues resulting from hydraulic fracture stimulation and we are not presently aware of any such matters.

In recent years, environmental opposition to hydraulic fracturing has increased, and various governmental and regulatory authorities are considering the adequacy of current regulations. In Colorado, the primary regulator is the Colorado Oil and Gas Conservation Commission, which requires parties engaged in hydraulic fracturing to disclose the concentrations of the chemicals used in the process. Some localities are considering more stringent regulation. We continue to monitor these developments, as we consider the process to be critical to our success.

Competition and Marketing

We are faced with strong competition from many other companies and individuals engaged in the oil and gas business, many are very large, well established energy companies with substantial capabilities and established earnings records. We may be at a competitive disadvantage in acquiring oil and gas prospects since we must compete with these individuals and companies, many of which have greater financial resources and larger technical staffs. It is nearly impossible to estimate the number of competitors; however, it is known that there are a large number of companies and individuals in the oil and gas business.

Exploration for and production of oil and gas are affected by the availability of pipe, casing and other tubular goods and certain other oil field equipment including drilling rigs and tools. We depend upon independent drilling contractors to furnish rigs, equipment and tools to drill our wells. Higher prices for oil and gas may result in competition among operators for drilling equipment, tubular goods and drilling crews, which may affect our ability expeditiously to drill, complete, recomplete and work-over wells.

The market for oil and gas is dependent upon a number of factors beyond our control, which at times cannot be accurately predicted. These factors include the proximity of wells to, and the capacity of, natural gas pipelines, the extent of competitive domestic production and imports of oil and gas, the availability of other sources of energy, fluctuations in seasonal supply and demand, and governmental regulation. In addition, there is always the possibility that new legislation may be enacted, which would impose price controls or additional excise taxes upon crude oil or natural gas, or both. Oversupplies of natural gas can be expected to recur from time to time and may result in the gas producing wells being shut-in. Imports of natural gas may adversely affect the market for domestic natural gas.

The market price for crude oil is significantly affected by policies adopted by the member nations of Organization of Petroleum Exporting Countries ("OPEC"). Members of OPEC establish prices and production quotas among themselves for petroleum products from time to time with the intent of controlling the current global supply and consequently price levels. We are unable to predict the effect, if any, that OPEC or other countries will have on the amount of, or the prices received for, crude oil and natural gas.

Gas prices, which were once effectively determined by government regulations, are now largely influenced by competition. Competitors in this market include producers, gas pipelines and their affiliated marketing companies, independent marketers, and providers of alternate energy supplies, such as residual fuel oil. Changes in government regulations relating to the production, transportation and marketing of natural gas have also resulted in significant changes in the historical marketing patterns of the industry.

Generally, these changes have resulted in the abandonment by many pipelines of long-term contracts for the purchase of natural gas, the development by gas producers of their own marketing programs to take advantage of new regulations requiring pipelines to transport gas for regulated fees, and an increasing tendency to rely on short-term contracts priced at spot market prices.

General

Our offices are located at 20203 Highway 60, Platteville, CO 80651. Our office telephone number is (970) 737-1073 and our fax number is (970) 737-1045.

The Platteville office and equipment yard is rented to us pursuant to a lease with HS Land & Cattle, LLC, a firm controlled by Ed Holloway and William E. Scaff, Jr., two of our officers. The lease requires monthly payments of $10,000 and expires on July 1, 2013.

As of October 15, 2012, we had 11 full time employees.

Neither we, nor any of our properties, are subject to any pending legal proceedings.

Available Information

We make available on our website, www.syrginfo.com, under “Investor Relations, SEC Filings,” free of charge, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports as soon as reasonably practicable after we electronically file or furnish them to the U.S. Securities and Exchange Commission (“SEC”).

The “Investor Relations, News / Events” pages on our website contain press releases and investor presentations with more recent information than may have been available at the time of the most recent filing with the SEC.

Our Code of Ethics and Board of Directors Committee Charters (Audit and Compensation Committees) are also available on our website under “Investor Relations, Corporate Governance.”

ITEM 1A. RISK FACTORS

Investors should be aware that any purchase of our securities involves certain risks, including those described below, which could adversely affect the value of our common stock. We do not make, nor have we authorized any other person to make, any representation about the future market value of our common stock. In addition to the other information contained in this annual report, the following factors should be considered carefully in evaluating an investment in our securities.

Laws and Regulations

Our operations will be affected from time to time and in varying degrees by political developments and Federal and state laws and regulations regarding the development, production and sale of crude oil and natural gas. These regulations require permits for drilling of wells and also cover the spacing of wells, the prevention of waste, and other matters. Rates of production of oil and gas have for many years been subject to Federal and state conservation laws and regulations and the petroleum industry is subject to Federal tax laws.

In addition, the production of oil or gas may be interrupted or terminated by governmental authorities due to ecological and other considerations. Compliance with these regulations may require a significant capital commitment by and expense to us and may delay or otherwise adversely affect our operations.

From time to time legislation has been proposed relating to various conservation and other measures designed to decrease dependence on foreign oil. No prediction can be made as to what additional legislation may be proposed or enacted. Oil and gas producers may face increasingly stringent regulation in the years ahead and a general hostility towards the oil and gas industry on the part of a portion of the public and of some public officials. Future regulation will probably be determined by a number of economic and political factors beyond our control or the oil and gas industry.

Our activities are subject to existing federal and state laws and regulations governing environmental quality and pollution control. Compliance with environmental requirements and reclamation laws imposed by Federal, state, and local governmental authorities may necessitate significant capital outlays and may materially affect our earnings. It is impossible to predict the impact of environmental legislation and regulations (including regulations restricting access and surface use) on our operations in the future although compliance may necessitate significant capital outlays, materially affect our earning power or cause material changes in our intended business. In addition, we may be exposed to potential liability for pollution and other damages.

Dry holes and non-productive wells

Oil and gas exploration is not an exact science, and involves a high degree of risk. The primary risk lies in the drilling of dry holes or drilling and completing wells, which, though productive, do not produce gas and/or oil in sufficient amounts to return the amounts expended and produce a profit. Hazards, such as unusual or unexpected formation pressures, downhole fires, blowouts, loss of circulation of drilling fluids and other conditions are involved in drilling and completing oil and gas wells and, if such hazards are encountered, completion of any well may be substantially delayed or prevented. In addition, adverse weather conditions can hinder or delay operations, as can shortages of equipment and materials or unavailability of drilling, completion, and/or work-over rigs. Even though a well is completed and is found to be productive, water and/or other substances may be encountered in the well, which may impair or prevent production or marketing of oil or gas from the well.

Exploratory drilling involves substantially greater economic risks than development drilling because the percentage of wells completed as producing wells is usually less than in development drilling. Exploratory drilling itself can be of varying degrees of risk and can generally be divided into higher risk attempts to discover a reservoir in a completely unproven area or relatively lower risk efforts in areas not too distant from existing reservoirs. While exploration adjacent to or near existing reservoirs may be more likely to result in the discovery of oil and gas than in completely unproven areas, exploratory efforts are nevertheless high risk activities.

Although the completion of oil and gas wells is, to a certain extent, less risky than drilling for oil and gas, the process of completing an oil or gas well is nevertheless associated with considerable risk. In addition, even if a well is completed as a producer, the well for a variety of reasons may not produce oil or gas in quantities sufficient to repay our investment in the well.

The acquisition, exploration and development of oil and gas properties, and the production and sale of oil and gas are subject to many factors not under our control. These factors include, among others, general economic conditions, proximity to pipelines, oil import quotas, supply, demand, and price of other fuels and the regulation of production, refining, transportation, pricing, marketing and taxation by various governmental authorities.

Supply and demand

Buyers of our gas, if any, may refuse to purchase gas from us in the event of oversupply. If we drill wells that are productive of natural gas, the quantities of gas that we may be able to sell may be too small to pay for the expenses of operating the wells. In such a case, the wells would be "shut-in" until such time, if ever, that economic conditions permit the sale of gas in quantities which would be profitable.

Insurable risks, defects, and hazards

Interests that we may acquire in oil and gas properties may be subject to royalty and overriding royalty interests, liens incident to operating agreements, liens for current taxes and other burdens and encumbrances, easements and other restrictions, any of which may subject us to future undetermined expenses. We do not intend to purchase title insurance, title memos, or title certificates for any leasehold interests we will acquire.

It is possible that at some point we will have to undertake title work involving substantial costs. In addition, it is possible that we may suffer title failures resulting in significant losses.

The drilling of oil and gas wells involves hazards such as blowouts, unusual or unexpected formations, pressures or other conditions, which could result in substantial losses or liabilities to third parties. Although we intend to acquire adequate insurance, or to be named as an insured under coverage acquired by others (e.g., the driller or operator), we may not be insured against all such losses because insurance may not be available, premium costs may be deemed unduly high, or for other reasons. Accordingly, uninsured liabilities to third parties could result in the loss of our funds or property.

Opposition to Hydraulic Fracturing

Hydraulic fracturing, the process used for releasing oil and gas from shale rock, has recently come under increased scrutiny and could be the subject of further regulation that could impact the timing and cost of development. While companies have been using the technique for decades, as drilling expands to more populated areas, environmentalists raise concern about the effects on the population's health and drinking water.

In April of this year, the Obama administration proposed the first national standards to control air pollution from gas wells stimulated by hydraulic fracturing. The EPA published claims that the new regulations would ensure pollution is controlled without slowing natural gas production, actually resulting in more product for fuel suppliers to bring to market. The proposal would restrict the venting of gases during the well completion phase, and require the implementation of a new technology to reduce emissions of pollutants during completion of wells. Implementation of the pollution-reducing equipment for so-called "green completions" is required by January 2015.

Locally, some counties and municipalities are attempting to impose more stringent regulations than those required by the Colorado Oil and Gas Conservation Commission. Litigation has been initiated to determine the legality of these attempts. Depending on the legislation that may ultimately be enacted or the regulations that may be adopted at the federal, state and/or local levels, exploration and production activities that entail hydraulic fracturing could be subject to additional regulation and permitting requirements. Individually or collectively, such new legislation or regulation could lead to operational delays or increased operating costs and could result in additional burdens that could increase the costs and delay the development of unconventional oil and gas resources from shale formations which are not commercial without the use of hydraulic fracturing. This could have an adverse effect on our business.

Related Party Transactions

Our transactions with related parties may cause conflicts of interests that may adversely affect us. Ed Holloway and William E. Scaff, Jr., both of whom are officers, directors and principal shareholders, control two entities, Petroleum Exploration & Management, LLC ("PEM") and HS Land & Cattle, LLC ("HSLC"), with whom we do business. We presently lease the Platteville office space and equipment storage yard from HSLC at a rate of $10,000 per month. During 2011, we purchased all of the operating oil and gas assets owned by PEM. Material transactions with related parties are approved by our independent directors.

We believe that the transactions and agreements that we have entered into with these affiliates are on terms that are at least as favorable as could reasonably have been obtained at such time from third parties. However, these relationships could create, or appear to create, potential conflicts of interest when our board of directors is faced with decisions that could have different implications for us and these affiliates. The appearance of conflicts, even if such conflicts do not materialize, might adversely affect the public's perception of us, as well as our relationship with other companies and our ability to enter into new relationships in the future, which could have a material adverse effect on our ability to do business.

Funding

Our failure to obtain capital may significantly restrict our proposed operations. We need additional capital to fund our capital expenditure plans. We do not know what the terms of any future capital raising may be but any future sale of our equity securities would dilute the ownership of existing stockholders and could be at prices substantially below the price investors paid for their shares of our common stock. Our failure to obtain the capital required will result in the slower implementation of our business plan. There can be no assurance that we will be able to obtain the necessary capital.

We will need to consistently generate positive cash flow or obtain additional financing until we are able to consistently yield sufficient cash essential for the growth of our operations in executing our strategic business plan.

As a result of our short operating history, it is difficult for potential investors to evaluate our business.

Market for our Common Stock

There is only a limited public market for our common stock. Although our common stock has been listed on the NYSE MKT since July 27, 2011, the trading in our stock has, at times, been limited and sporadic. Additionally, the trading price of our common stock may fluctuate widely in response to various factors, some of which are beyond our control. Factors that could negatively affect our share price include, but are not limited to:

- actual or anticipated fluctuations in our quarterly results of operations;
- liquidity;
- sales of common stock by our shareholders;
- changes in oil and natural gas prices;
- changes in our cash flow from operations or earnings estimates;
- publication of research reports about us or the oil and natural gas exploration and production industry generally;
- increases in market interest rates which may increase our cost of capital;
- changes in applicable laws or regulations, court rulings and enforcement and legal actions;
- changes in market valuations of similar companies;
- adverse market reaction to any indebtedness we incur in the future;
- additions or departures of key management personnel;
- actions by our shareholders;

- commencement of or involvement in litigation;
- news reports relating to trends, concerns, technological or competitive developments, regulatory changes and other related issues in our industry;
- speculation in the press or investment community regarding our business;
- general market and economic conditions; and
- domestic and international economic, legal and regulatory factors unrelated to our performance.

Shares issuable upon the exercise of outstanding warrants and options may substantially increase the number of shares available for sale in the public market and may depress the price of our common stock. We have outstanding options and warrants which could potentially allow the holders to acquire a substantial number of shares of our common stock. Until the options and warrants expire, the holders will have an opportunity to profit from any increase in the market price of our common stock without assuming the risks of ownership. Holders of options and warrants may exercise these securities at a time when we could obtain additional capital on terms more favorable than those provided by the options or warrants. The exercise of the options and warrants will dilute the voting interest of the current owners of our outstanding shares by adding a substantial number of additional shares of common stock.

Reliance on Key Personnel

We are dependent upon the contributions of our senior management team and other key employees for our success. If one or more of these executives, or other key employees, were to cease to be employed by us, our progress could be adversely affected. In particular, we may have to incur costs to replace senior executive officers or other key employees who leave, and our ability to execute our business strategy could be impaired if we are unable to replace such persons in a timely manner.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 2. PROPERTIES

See Item 1 of this report.

ITEM 3. LEGAL PROCEEDINGS

None.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is listed on the NYSE MKT under the symbol "SYRG".

Trading of our stock on the NYSE Amex (predecessor to the NYSE MKT) began on July 27, 2011. Prior to listing on the NYSE Amex, our stock traded on the OTC Bulletin Board.

Shown below is the range of high and low sales prices for our common stock as reported by the NYSE MKT since July 27, 2011. Prior to July 27, 2011, the high and low prices were reported by the OTC Bulletin Board. Market quotations from the OTC Bulletin Board reflect inter-dealer prices, without retail mark-up, mark-down or commissions and may not necessarily represent actual transactions.

Quarter Ended	High	Low
November 30, 2010	$2.40	$1.95
February 28, 2011	$4.74	$2.25
May 31, 2011	$4.90	$3.20
August 31, 2011	$3.69	$2.55

Quarter Ended	High	Low
November 30, 2011	$3.75	$2.20
February 29, 2012	$3.72	$2.42
May 31, 2012	$3.65	$2.52
August 31, 2012	$3.10	$2.40

As of October 15, 2012, the closing price of our common stock on the NYSE MKT was $4.22.

As of October 15, 2012, we had 51,637,924 outstanding shares of common stock and 189 shareholders of record. The number of beneficial owners of our common stock is approximately 2,100.

Since inception, we have not paid any cash dividends on common stock. Cash dividends are restricted under the terms of our credit facility and we presently intend to continue the policy of using retained earnings for expansion of our business.

Our articles of incorporation authorize our board of directors to issue up to 10,000,000 shares of preferred stock. The provisions in the articles of incorporation relating to the preferred stock allow our directors to issue preferred stock with multiple votes per share and dividend rights, which would have priority over any dividends paid with respect to the holders of our common stock. The issuance of preferred stock with these rights may make the removal of management difficult even if the removal would be considered beneficial to shareholders generally, and will have the effect of limiting shareholder participation in certain transactions such as mergers or tender offers if these transactions are not favored by our management.

Additional Shares Which May be Issued

The following table lists additional shares of our common stock, which may be issued as of October 15, 2012, upon the exercise of outstanding options or warrants or the issuance of shares for oil and gas leases.

	Number of Shares	Note Reference
Shares issuable upon the exercise of Series C warrants	9,000,000	A
Shares issuable upon the exercise of placement agent warrants	769,601	A
Shares issuable upon exercise of Series A warrants that were granted to those persons owning shares of our common stock prior to the acquisition of Predecessor Synergy	1,038,000	B
Shares issuable upon exercise of Series A warrants sold in prior private offering	2,060,000	C
Shares issuable upon exercise of Series A and Series B warrants	2,000,000	D
Shares issuable upon exercise of sales agent warrants	126,932	D
Shares issuable upon exercise of warrants issued for services provided	100,000	E
Shares issuable upon exe rcise of options held by our officers and employees	4,915,000	F

A. Between December 2009 and March 2010, we sold 180 Units at a price of $100,000 per Unit to private investors. Each Unit consisted of one $100,000 note and 50,000 Series C warrants. The notes were convertible into shares of our common stock at a conversion price of $1.60 per share, at the option of the holder. Each Series C warrant entitles the holder to purchase one share of our common stock at a price of $6.00 per share at any time prior to December 31, 2014. Between June 2010 and March 2011, note-holders converted all notes into 11,250,000 shares of our common stock.

We paid Bathgate Capital Partners (now named GVC Capital), the placement agent for the Unit offering, a commission of 8% of the amount Bathgate Capital raised in the Unit offering. We also sold to the placement agent, for a nominal price, warrants to purchase 1,125,000 shares of our common stock at a price of $1.60 per share. The placement agent's warrants expire on December 31, 2014. As of October 15, 2012, warrants to purchase 355,399 shares had been exercised by their holders.

B. Each shareholder of record on the close of business on September 9, 2008, received one Series A warrant for each share which they owned on that date (as adjusted for a reverse split of our common stock which was effective on September 22, 2008). Each Series A warrant entitles the holder to purchase one share of our common stock at a price of $6.00 per share at any time prior to December 31, 2012.

C. Prior to our acquisition of a corporation on September 9, 2008, that corporation sold 1,000,000 Units at a price of $1.00 per Unit and 1,060,000 Units at a price of $1.50 per Unit to private investors. Each Unit consisted of one share of Predecessor Synergy's common stock and one Series A warrant. In connection with the acquisition, these Series A warrants were exchanged for 2,060,000 of our Series A warrants. The Series A warrants are identical to the Series A warrants described in Note B above.

D. Between December 1, 2008 and June 30, 2009, we sold 1,000,000 units at a price of $3.00 per unit. Each unit consisted of two shares of our common stock, one Series A warrant and one Series B warrant. The Series A warrants are identical to the Series A warrants described in Note B above. Each Series B warrant entitles the holder to purchase one share of our common stock at a price of $10.00 per share at any time prior to December 31, 2012.

In connection with this unit offering, we paid the sales agent for the offering a commission of 10% of the amount the sales agent sold in the offering. We also issued warrants to the sales agent. The warrants allow the sales agent to purchase 31,733 units (which units were identical to the units sold in the offering) at a price of $3.60 per unit. The sales agent warrants will expire on the earlier of December 31, 2012, or twenty days following written notification from us that our common stock had a closing bid price at or above $7.00 per share for any ten of twenty consecutive trading days.

E. During the fiscal year ended August 31, 2012, we entered into an agreement with a public relations firm, and agreed to issue warrants to the firm in exchange for services provided. For the one year term, warrants to purchase 100,000 shares of stock at $2.69 per share are available to the firm and become exercisable at quarterly intervals upon our being satisfied with the firm's services.

F. See Item 11 of this report for information regarding shares issuable upon exercise of options held by our officers and employees.

ITEM 6. SELECTED FINANCIAL DATA

The selected financial data presented in this item has been derived from our audited financial statements that are either included in this report or in reports previously filed with the U.S. Securities and Exchange Commission. The information in this item should be read in conjunction with the financial statements and accompanying notes and other financial data included in this report.

	For the Fiscal Year Ended				Inception (December 28 2007) to
	2012	2011	2010	2009	August 31, 2008
Results of Operations:					
Revenues	$ 24,969,213	$ 10,001,668	$ 2,158,444	$ 94,121	$ —
Net income (loss)	12,123,942	(11,600,158)	(10,794,172)	(12,351,873)	(193,378)
Net income (loss) per common share:					
Basic	$ 0.26	$ (0.45)	$ (0.88)	$ (1.14)	$ (0.07)
Diluted	$ 0.25	$ (0.45)	$ (0.88)	$ (1.14)	$ (0.07)
Certain Balance Sheet Information:					
Total Assets	$ 120,731,288	$ 63,697,885	$ 24,841,913	$ 4,832,568	$ 2,319,753
Working Capital	10,874,773	684,545	6,236,979	2,248,968	2,266,427
Total Liabilities	19,619,129	14,589,872	25,858,862	1,844,124	53,326
Equity (Deficit)	101,112,159	49,108,013	(1,016,949)	2,988,444	2,266,427
Certain Operating Statistics:					
Production:					
Oil (Bbls)	235,691	89,917	21,080	1,730	—
Gas (Mcf)	1,109,057	450,831	141,154	4,386	—
Total production in BOE	420,534	165,056	44,606	2,461	—
Average sales price per BOE	$ 59.38	$ 59.24	$ 48.39	$ 38.25	—
LOE per BOE	$ 2.89	$ 2.94	$ 1.94	$ 4.70	—
DDA per BOE	$ 14.29	$ 16.62	$ 15.52	$ 39.54	—

The fluctuation in results of operations and financial position is due in part to acquisitions of producing oil and gas properties coupled with the aggressive drilling program we executed during 2010, 2011 and 2012.

See Note 15 to the Financial Statements included as part of this report for our quarterly financial data.

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

Introduction

The following discussion and analysis was prepared to supplement information contained in the accompanying financial statements and is intended to explain certain items regarding the financial condition as of August 31, 2012, and the results of operations for the years ended August 31, 2012, 2011 and 2010. It should be read in conjunction with the "Selected Financial Data" and the accompanying audited financial statements and related notes thereto contained in this annual report on Form 10-K.

This section and other parts of this Annual Report on Form 10-K contain forward-looking statements that involve risks and uncertainties. See the "Cautionary Note Regarding Forward-Looking Statements" at the beginning of this Annual Report on Form 10-K. Forward-looking statements are not guarantees of future performance and our actual results may differ significantly from the results discussed in the forward-looking statements. Factors that might cause such differences include, but are not limited to, those discussed in the subsection entitled "Risk Factors" above, which are incorporated herein by reference. We assume no obligation to revise or update any forward-looking statements for any reason, except as required by law.

Overview

Synergy Resources Corporation ("we," "our," "us" or "the Company") is a growth-oriented independent oil and gas company engaged in the acquisition, development, and production of crude oil and natural gas in and around the Denver-Julesburg Basin ("D-J Basin") of Colorado. All of our producing wells are in the Wattenberg Field, which has a history as one of the most prolific production areas in the country. During 2011, we expanded our undeveloped acreage holdings in eastern Colorado and western Nebraska, and may commence development activities in these areas.

Since commencing active operations in September 2008, we have undergone significant growth. As disclosed in the following table, as of August 31, 2012, we have drilled, acquired, or participated in 209 gross oil and gas wells and have successfully completed 191 wells that were in production. There were 18 wells in progress at August 31, 2012.

	Operated		Participated		
Year	Drilled	Completed	Drilled	Completed	Acquired
2009	—	—	2	2	—
2010	36	22	—	—	—
2011	20	28	11	11	72
2012	51	47	13	5	4
Total	107	97	26	18	76

As of August 31, 2012, we:

- were the operator of 146 wells that were producing oil and gas and the operator of 10 wells that were in the completion process and we were participating as a non-operating working interest owner in 45 producing wells and 8 wells that were in progress;
- held approximately 222,085 gross acres and 187,751 net acres under lease; and
- had estimated proved reserves of 5.1 million barrels ("Bbls") of oil and 33.4 billion cubic feet ("Bcf") of gas.

Estimated BOE proved reserves increased 140% during the fiscal year 2012, primarily as a result of the success achieved under the 2012 drilling program.

Our strategy for continued growth includes additional drilling activities, acquisition of existing wells, and recompletion of wells to more rapidly access and/or extend reserves through improved hydraulic stimulation techniques. We attempt to maximize our return on assets by drilling and operating wells in which we have a majority net revenue interest. We attempt to limit our risk by drilling in proven areas. To date, we have not drilled any dry holes. All wells drilled prior to 2012 were relatively low-risk vertical or directional wells. However, the increased pace of horizontal drilling activity in the D-J Basin by numerous operators has provided us with the opportunity to witness best practices in the industry first hand. Consequently, we agreed to participate in our first horizontal well, which began drilling operations in January 2012 and commenced production in March 2012. The introduction of horizontal drilling to the D-J Basin has accelerated the retrieval of natural gas reserves in the Niobrara Shale and Codell formations. We subsequently agreed to participate in additional horizontal wells. By the end of August, we were a participant in three horizontal wells that were in production, two wells that were in the completion phase and one well that was in the drilling phase. We expect to participate in additional horizontal wells and we are preparing to drill and operate horizontal wells for our own account during our 2013 fiscal year.

Historically, our cash flow from operations was not sufficient to fund our growth plans and we relied on proceeds from the sale of debt and equity securities. Our cash flow from operations is increasing, and we plan to finance an increasing percentage of our growth with internally generated funds. Ultimately, implementation of our growth plans will be dependent upon the success of our operations and the amount of financing we are able to obtain.

Results of Operations

Material changes of certain items in our statements of operations included in our financial statements for the periods presented are discussed below.

<u>For the year ended August 31, 2012, compared to the year ended August 31, 2011</u>

For the year ended August 31, 2012, we reported net income of $12,123,942, or $0.26 per share, $0.25 per diluted share, compared to a net loss of $(11,600,158), or $(0.45) per basic and diluted share for the period ended August 31, 2011.

Our rapid improvement in profitability was driven by our successful drilling program. The significant variances between the two years are (i) increased revenues and expenses associated with more producing wells, (ii) the cessation of certain interest and other non-cash expenses, and (iii) the effect of income taxes. As further explained below, our net loss for 2011 resulted from non-cash charges related to the convertible promissory notes and the derivative conversion liability. The following discussion also expands upon items of inflow and outflow that affect operating income.

Oil and Gas Production and Revenues – For the year ended August 31, 2012, we recorded total revenues of $24,969,213 compared to $10,001,668 for the year ended August 31, 2011, an increase of $14,967,545 or 150%. We experienced an overall 151% annual increase in production from the prior year having realized a full year of production from wells at the beginning of the year, and the addition of wells, including new wells drilled as well as those acquired. Although there was significant commodity price fluctuation during the year, overall pricing on a BOE basis was not significantly different from 2011 to 2012. For the fiscal year ended August 31, 2012, our gas / oil ratio ("GOR") on a BOE basis was 44/56 compared to 45/55 for the fiscal year ended August 31, 2011.

	Year Ended August 31,	
	2012	2011
Production:		
Oil (Bbls[1])	235,691	89,917
Gas (Mcf[2])	1,109,057	450,831
Total production in BOE[3]	420,534	165,056
Revenues:		
Oil	$ 20,643,863	$ 7,469,709
Gas	4,325,350	2,307,463
Total	$ 24,969,213	$ 9,777,172
Average sales price:		
Oil (Bbls[1])	$ 87.59	$ 83.07
Gas (Mcf[2])	$ 3.90	$ 5.12
BOE[3]	$ 59.38	$ 59.24

1 "Bbl" refers to one stock tank barrel, or 42 U.S. gallons liquid volume in reference to crude oil or other liquid hydrocarbons.

2 "Mcf" refers to one thousand cubic feet of natural gas.

3 "BOE" refers to barrel of oil equivalent, which combines Bbls of oil and Mcf of gas by converting each six Mcf of gas to one Bbl of oil.

As of August 31, 2012, we had 191 producing wells. Net oil and gas production averaged 1,149 BOE per day in 2012, as compared with 452 BOE per day for 2011, a year over year increase of 154% in BOEPD production. The significant increase in production from the prior year reflects 52 additional wells that went into productive status since August 31, 2011 and a full year of production from the 111 wells that were added over the course of fiscal year 2011. Production for the fourth fiscal quarter of 2012 averaged 1,270 BOE per day.

Revenues are sensitive to changes in commodity prices. From 2011 to 2012, our realized annual average sales price per barrel of oil rose 5%; however, we experienced a decline of 24% in our realized annual average sales price per Mcf of natural gas. There was a 45% and 130% swing in the price of crude and natural gas from the respective low to high prices during the twelve month period ended August 31, 2012. Barrel and Mcf prices at year end were up 2% and down 9%, respectively, from twelve month average. We did not utilize any commodity price hedges during either year, but expect to do so in the future.

While our balanced production mix of oil and gas and the high liquid content of our gas help to mitigate the negative effect of volatility in commodity prices, downward price pressure could have a negative effect on revenues reported in future periods.

Lease Operating Expenses ("LOE") and Production Taxes – Direct operating costs of producing oil and natural gas and taxes on production and properties are reported as lease operating expenses as follows:

	Year ended August 31,	
	2012	2011
Production costs	$ 1,146,294	$ 350,853
Work-over	66,431	86,797
Other	—	46,463
Lifting cost	1,212,725	484,113
Severance and ad valorem taxes	2,435,740	955,705
Total LOE	$ 3,648,465	$ 1,439,818
Per BOE:		
Production costs	$ 2.73	$ 2.13
Work-over	0.16	0.53
Other	—	0.28
Lifting cost	2.89	2.94
Severance and ad valorem taxes	5.79	5.79
Total LOE per BOE	$ 8.68	$ 8.73

Lease operating and work-over costs tend to fluctuate with the number of producing wells, and, to a lesser extent, on variations in oil field service costs and changes in the production mix of crude oil and natural gas. From 2011 to 2012, we experienced an increase in production cost per BOE in connection with additional costs to bolster output from some of our older wells. Taxes, the largest component of lease operating expenses, generally move with the value of oil and gas sold. As a percent of revenues, taxes averaged 10% in both 2012 and 2011.

Depletion, Depreciation and Amortization ("DDA") – We recognized DDA expense of $6,009,510 and $2,838,307 for the fiscal years ended August 31, 2012 and 2011, respectively, of which $5,837,788 and $2,743,441 was the depletion of oil and gas properties for 2012 compared to 2011. Depletion expense more than doubled, primarily as a result of growth in production and producing properties from 2011 to 2012.

Capitalized costs of evaluated oil and gas properties are depleted quarterly using the units-of-production method based on estimated reserves, wherein the ratio of production volumes for the quarter to beginning of quarter estimated total reserves determine the depletion rate. For fiscal year 2012, our depletable reserve base was 5,321,502 barrels of oil and 34,555,031 Mcf of natural gas. Fiscal year 2012 production represented 4% and 3% of those reserve bases, respectively.

Depletion expense per BOE declined 16% from 2011 to 2012. For the fiscal year ended August 31, 2012, depletion of oil and gas properties was $13.88 per BOE compared to $16.62 for the fiscal year ended August 31, 2011. During 2012, we have been able to increase reserves and production faster than the increase in capitalized costs, which caused the decline in the expense per BOE.

General and Administrative ("G&A") – The following table summarizes the components of general and administration expenses:

	Year Ended August 31,	
	2012	2011
Cash based compensation	$ 1,901,296	$ 1,260,688
Share based compensation	473,040	627,486
Professional fees	953,162	716,210
Insurance	136,167	78,127
Other general and administrative	438,425	427,025
Capitalized general and administrative	(345,343)	(206,233)
Total G&A	$ 3,556,747	$ 2,903,303

Although G&A costs increased during 2012, they increased at a lower rate than the overall growth of our business, as we strive to maintain an efficient overhead structure. For the fiscal year ended August 31, 2012, G&A was $8.46 per BOE compared to $17.59 for the fiscal year ended August 31, 2011.

Cash based compensation and benefits include payments to employees and directors. Share based compensation is associated with compensation in the form of either stock options or common stock grants for employees, directors, and service providers. The amount of expense recorded for stock options is calculated using the Black-Scholes-Merton option pricing model, while the amount of expense recorded for common stock grants is calculated based upon the closing market value of the shares on the date of grant.

Professional fees have increased as we have grown our business. The two primary factors driving this increase are the additional accounting and auditing fees incurred in connection with operating as a public company, and the additional professional services required to meet the compliance requirements of the Sarbanes–Oxley Act, as we have progressed from a smaller reporting company to an accelerated filer under SEC definitions. The listing on the NYSE: MKT contributed to costs in excess of those reported in the comparable prior year period when our stock was listed on the OTC Bulletin Board.

Pursuant to the requirements under the full cost accounting method for oil and gas properties, we identify all general and administrative costs that relate directly to the acquisition of undeveloped mineral leases and the development of properties. Those costs are reclassified from general and administrative expenses and capitalized into the full cost pool. The increase in capitalized costs from 2011 to 2012 reflects our increasing activities to acquire leases and develop the properties.

Operating Income (Loss) – For the year ended August 31, 2012, we generated operating income of $11,754,491, compared to $2,820,240 for the year ended August 31, 2011. This tri-fold increase in operating income resulted primarily from the increasing contribution of wells brought into production during the last two years, which includes wells drilled under the 2012 and 2011 drilling programs, the acquisition of producing properties from PEM and other parties, and increased production from older wells that were recompleted using newer hydraulic fracturing techniques. Increased revenues more than offset increased costs incurred by us to accomplish these objectives.

Other Income (Expense) – Other income for the fiscal year ended August 31, 2012 was $37,451, consisting solely of interest income. Interest cost of $208,344 was incurred during 2012, all of which was capitalized as part of the cost of oil and gas properties. For the fiscal year ended August 31, 2011, we reported several significant items of expense in addition to interest income of $55,776. These other expenses reported in 2011 primarily related to our convertible promissory notes, including net interest expense of $589,539, accretion of debt discount of $2,664,138, amortization of debt issuance costs of $1,587,799, and a change in the fair value of the derivative conversion liability of $10,229,229. During 2011, interest expense was also recorded on the related party note and the bank line of credit in the amounts of $74,047 and $41,559, respectively. Of these expenses, we capitalized interest and amortization of $710,137.

The convertible promissory notes contained a conversion feature which was considered an embedded derivative and recorded as a liability at its initial estimated fair value. This derivative conversion liability was then marked-to-market over time, with the resulting change in fair value recorded as a non-cash item in the statement of operations. All expenses related to the convertible promissory notes ceased mid-year 2011, as all noteholders converted their holdings into equity.

Income Taxes – We reported income tax expense of $4,579,000 offset by a tax benefit of $4,911,000 for the fiscal year ended August 31, 2012, resulting in a net income tax benefit of $332,000 and a corresponding net deferred tax asset in the same amount. For all reporting periods prior to 2012, no income tax expense or benefit was reported, as all tax assets or liabilities were effectively offset by a valuation allowance.

The income tax benefit is a one-time event representing the expected value of the future deduction of the net operating loss carry-forward generated during our start-up years.

Each year, management evaluates all the positive and negative evidence regarding our tax position and reaches a conclusion on the most likely outcome. During the current fiscal year, we concluded that it was more likely than not that we would be able to realize a benefit from the net operating loss carry-forward, and we released our entire valuation allowance of $4,911,000. Prior to 2012, management concluded that it was more likely than not that our net deferred tax asset would not be realized in the foreseeable future and, accordingly, a full valuation allowance was provided against the net deferred tax asset.

During 2012 management concluded that positive indicators outweighed negative indicators and that it was appropriate to release the valuation allowance. Although we reported net losses every year since inception through August 31, 2011, we attributed all of the net losses for the 2011 and 2010 fiscal years to a single discrete item. The discrete item was the fair value accounting treatment of the components of the convertible promissory notes issued in 2010, which created non-cash expenses for accretion of debt discount, amortization of issuance costs, and change in fair value of derivative liability. As all of the convertible notes were converted, those expenses will not recur, and it is appropriate to exclude them from a consideration of future profitability. Secondly, we had begun to report net income and had significantly increased oil and gas reserve values. Lastly, we completed a debt financing arrangement and an equity financing arrangement that allow us to continue with our operating plan. Accordingly, we believed that it was appropriate to release the valuation allowance related to the deferred tax asset created by the net operating loss carryover.

Future reporting periods are expected to report income tax expense at an estimated effective tax rate of approximately 37%.

For the year ended August 31, 2011, compared to the year ended August 31, 2010

For the year ended August 31, 2011, we reported a net loss of $(11,600,158), or $(0.45) per share, compared to a net loss of $(10,794,172), or $(0.88) per share for the period ended August 31, 2010. As explained below, the net loss for each year is significantly affected by non-cash charges related to the convertible promissory notes and the derivative conversion liability. The following discussion also expands upon items of inflow and outflow that affect operating income. In most cases, the nature of the change from 2010 to 2011 involves the significant growth in number of producing properties and activities to acquire additional undeveloped acreage and proved properties.

Oil and Gas Production and Revenues – For the year ended August 31, 2011, we recorded total oil and gas revenues of $9,777,172 compared to $2,158,444 for the year ended August 31, 2010, as summarized in the following table:

	Year Ended August 31,	
	2011	2010
Production:		
Oil (Bbls[1])	89,917	21,080
Gas (Mcf[2])	450,831	141,154
Total production in BOE	165,056	44,606
Revenues:		
Oil	$ 7,469,709	$ 1,441,562
Gas	2,307,463	716,882
Total	$ 9,777,172	$ 2,158,444
Average sales price:		
Oil (Bbls[1])	$ 83.07	$ 68.38
Gas (Mcf[2])	$ 5.12	$ 5.08

1 "Bbl" refers to one stock tank barrel, or 42 U.S. gallons liquid volume in reference to crude oil or other liquid hydrocarbons.

2 "Mcf" refers to one thousand cubic feet of natural gas.

3 "BOE" refers to barrel of oil equivalent, which combines Bbls of oil and Mcf of gas by converting each six Mcf of gas to one Bbl of oil.

Net oil and gas production for the year ended August 31, 2011, was 165,056 BOE, or 452 BOE per day, as compared with 44,606 BOE, or 122 BOE per day, for the year ended August 31, 2010. The significant increase in production from the prior year resulted from realizing a full year of production from wells at the beginning of the year, and the addition of wells, including new wells drilled and those acquired in the PEM acquisition. Production for the fourth fiscal quarter of 2011 averaged 577 BOE per day.

Lease Operating Expenses – As summarized in the following table, our lease expenses include the direct operating costs of producing oil and natural gas, taxes on production and properties, and well work-over costs:

	Year ended August 31,	
	2011	2010
Production costs	$ 350,853	$ 86,554
Work-over	86,797	—
Other	46,463	—
Lifting cost	484,113	386,554
Severance and ad valorem taxes	955,705	236,966
Total LOE	$ 1,439,818	$ 323,520
Per BOE:		
Production costs	$ 2.13	$ 1.94
Work-over	0.53	—
Other	0.28	—
Lifting cost	2.94	1.94
Severance and ad valorem taxes	5.79	5.31
Total LOE per BOE	$ 8.73	$ 7.25

Lease operating and work-over costs tend to increase or decrease primarily in relation to the number of wells in production, and, to a lesser extent, on fluctuation in oil field service costs and changes in the production mix of crude oil and natural gas. Taxes tend to increase or decrease primarily based on the value of oil and gas sold, and, as a percent of revenues, averaged 10% in 2011 and 11% in 2010.

Depletion, Depreciation and Amortization ("DDA") – DDA expense is summarized in the following table:

	Year ended August 31,			
	2011		2010	
Depletion – oil and gas assets	$	2,743,441	$	692,274
Depreciation and amortization – other assets		57,138		7,592
Accretion of asset retirement obligations		37,728		1,534
Total DDA	$	2,838,307	$	701,400
Depletion expense per BOE	$	16.62	$	15.52

The determination of depletion, depreciation and amortization expense is highly dependent on the estimates of the proved oil and natural gas reserves and actual production volumes. As of August 31, 2011, we had 4,446,565 BOE of estimated net proved reserves compared to 1,423,524 BOE of estimated net proved reserves as of August 31, 2010. Depletion expense per BOE increased approximately 7% as a result of cost increases across all of our operating sectors, including costs incurred for lease acquisition, drillings, and well completion.

Impairment of Oil and Gas Properties – We use the full cost accounting method, which requires recognition of impairment when the total capitalized costs of oil and gas properties exceed the "ceiling" amount, as defined in the full cost accounting literature. During the years ended August 31, 2011 and 2010, no impairment was recorded because our capitalized costs subject to the ceiling test were less than the estimated future net revenues from proved reserves discounted at 10% plus the lower of cost or market value of unevaluated properties. The ceiling test is performed each quarter and there is the possibility for impairments to be recognized in future periods. Once impairment is recognized, it cannot be reversed.

General and Administrative – The following table summarizes the components of general and administration expenses:

	Year Ended August 31,			
	2011		2010	
Cash based compensation	$	1,260,688	$	536,627
Share based compensation		627,486		581,233
Professional fees		716,210		419,588
Insurance		78,127		62,528
Other general and administrative		427,025		410,548
Capitalized general and administrative		(206,233)		(95,475)
Total G&A	$	2,903,303	$	1,915,049

Cash based compensation includes payments to employees. The increase of $724,061 from 2010 to 2011 reflects the expansion of our business, including the addition of 5 employees during the year. Stock-based compensation includes compensation paid to employees, directors, and service providers in the form of stock options or shares of common stock.

The amount of expense recorded for stock options is calculated by using the Black-Scholes-Merton option pricing model. The amount of expense recorded for shares of common stock is calculated based upon the closing market value of the shares.

The increase in professional fees includes certain accounting fees and investment banking fees related to the acquisition of assets from PEM. In addition, our progression from smaller reporting company to accelerated filer required additional professional services related to our compliance with the rules and regulations of Sarbanes–Oxley.

Pursuant to the requirements under the full cost accounting method for oil and gas properties, we identify all general and administrative costs that relate directly to the acquisition of undeveloped mineral leases and the development of properties. Those costs are reclassified from general and administrative expenses and capitalized into the full cost pool. The increase in capitalized costs from 2010 to 2011 reflects our increasing activities to acquire leases and develop the properties.

Operating Income (Loss) – For the year ended August 31, 2011, we generated operating income of $2,820,240, as compared with an operating loss of $781,525 for the year ended August 31, 2010. This increase of $3,601,765 resulted primarily from the increasing contribution of wells brought into production during the two fiscal years, which includes wells drilled under the 2011 and 2010 drilling programs, the acquisition of producing properties from PEM and other parties, and increased production from older wells that were recompleted using newer hydraulic fracturing techniques. Increased revenues more than offset increased costs incurred by us to accomplish these objectives.

Other Income (Expense) – During the year ended August 31, 2011, we recognized $14,420,398 in other expense compared to $10,012,647 during the comparable period in 2010. During 2011, interest expense was also recorded on the related party note and the bank line of credit in the amounts of $74,047 and $41,559, respectively. Of these expenses, we capitalized interest and amortization of $710,137 compared to $269,761 capitalized in 2010.

The amounts included in other income (expense) are primarily related to components of the 8% convertible promissory notes. The 8% convertible promissory notes contained a conversion feature, which was considered an embedded derivative and recorded as a liability at its initial estimated fair value. This derivative conversion liability was then marked-to-market over time, with the resulting change in fair value recorded as a non-cash item in the statement of operations. Prior to August 31, 2011, all of the notes had been converted, thereby eliminating the derivative conversion liability. We recognized a non-cash expense of $10,229,229 and $7,678,457 during the years ending August 31, 2011 and 2010, respectively, related to the change in fair value of the derivative conversion liability.

Interest expense, net, contained several components related to the 8% convertible promissory notes. In addition to the 8% coupon rate, we recorded amortization of debt issue costs of $1,587,799 and accretion of debt discount of $2,664,137 during the year ended August 31, 2011. During the year ended August 31, 2010, amortization of debt issue costs was $453,656 and accretion of debt discount was $1,333,590. In connection with the conversion of the remaining 8% convertible promissory notes outstanding during 2011, the Company accelerated its recognition of all remaining amounts for unamortized debt issuance costs and debt discount and the acceleration is included in the amounts presented above.

Income Taxes – Income taxes had no impact on our results of operations for the fiscal years ended August 31, 2011 and 2010, as we had reported a net loss every year since inception and for tax purposes had a net operating loss carry-forward (“NOL”) of approximately $11.3 million. The NOL is available to offset future taxable income. As of August 31, 2011 and 2010, management concluded that it was more likely than not that we would not be able to realize the benefits of our tax assets in the foreseeable future, therefore a full valuation allowance had been provided against deferred tax assets as of August 31, 2011 and 2010.

Liquidity and Capital Resources

Our primary source of liquidity since inception has been net cash provided by sales and other issuances of equity and debt securities. Our secondary sources of capital have been cash flow from operations, proceeds from the sale of properties, and borrowings under bank credit facilities. Our primary use of capital has been for the exploration, development and acquisition of oil and natural gas properties. Our future success in growing proved reserves and production will be highly dependent on capital resources available to us. While we believe that we have sufficient liquidity available to us from cash flows from operations and under our revolving credit facility unforeseen events may require us to obtain additional equity or debt financing. We have on file with the SEC an effective universal shelf registration statement that we may use for future securities offerings. Terms of future financings may be unfavorable, and we cannot assure investors that funding will be available on acceptable terms.

In November 2011, we modified our borrowing arrangement with Community Banks of Colorado, successor in interest to Bank of Choice, to increase the maximum allowable borrowings and to reduce the interest rate. In April 2012, the agreement was amended to further increase the borrowing base. The revolving line of credit provides us a borrowing capacity to $20 million. Outstanding borrowings accrue interest at the greater of 3.25% annually or the bank’s prime rate, which was also 3.25% at August 31, 2012. The maturity date for the arrangement is November 30, 2014.

The arrangement contains covenants that, among other things, restrict the payment of dividends and require compliance with certain financial ratios, for which we were fully in compliance as of August 31, 2012. The borrowing arrangement is collateralized by certain of our assets, including producing properties. Maximum borrowings are subject to reduction based upon a borrowing base calculation. As of August 31, 2012, the borrowing base calculation was not restrictive. We utilized a portion of the financing available through this arrangement to retire amounts outstanding under our related party note payable.

At August 31, 2012, we had cash and cash equivalents of $19,284,382 and a $17,000,000 balance available under our revolving credit facility.

On October 18, 2012, we entered into an amendment to this revolving line of credit agreement. The amended terms include an increase from $20 million to $30 million in the maximum amount of borrowings available, subject to certain collateral requirements. Other terms of the agreement, including interest on borrowed amounts and the commitment expiration date of November 30, 2014, were not materially changed.

Proceeds from any future borrowings are expected to be used primarily to fund lease acquisitions and drilling and completion costs.

On December 30, 2011, we completed the sale of 14.6 million shares of common stock in a public offering at a price of $2.75 per share. We netted $37,421,783 in proceeds, after deductions for the underwriting discounts, commissions and expenses of the offering.

We do not currently engage in any commodity hedging activities, although we may do so in the future.

We believe that the proceeds from our equity offering, plus cash flow from operations, plus additional borrowings available under our revolving line of credit will be sufficient to meet our liquidity needs during the remainder of this fiscal year. The amount, timing and allocation of capital expenditures is generally within our control, as participations are a limited portion of our operations. Fluctuations in prices for oil and natural gas could cause us to defer or accelerate our spending.

Our sources and (uses) of funds for the fiscal years ended August 31, 2012, 2011 and 2010, are shown below:

	Year Ended August 31,		
	2012	2011	2010
Cash provided by (used in) operations	$ 21,252,102	$ 7,916,308	$ (2,443,059)
Acquisition of oil and gas propertiesand equipment	(46,751,260)	(30,247,327)	(9,152,175)
Proceeds from sales of oil and gas properties	71,251	8,382,167	—
Proceeds from sale of convertible notes, net of debt issuance costs	—	—	16,651,023
(Repayment) of related party debt	(5,200,000)	—	—
(Repayment) / proceeds from bank loan	3,000,000	—	(1,161,811)
Proceeds from sale of common stock, net of offering costs	37,421,783	16,690,721	—
Net increase in cash	$ 9,793,876	$ 2,741,869	$ 3,893,978

Net cash provided by operating activities was $21,252,102 and $7,916,308 for the years ended August 31, 2012 and 2011, respectively. The significant improvement reflects the operating contribution from 2011 wells that were producing for the entire year, plus the contribution from wells that began production during 2012.

In addition to our analysis using amounts included in the cash flow statement, we evaluate operations using a non-GAAP measure called “adjusted cash flow from operations”, which adjusts for cash flow items that merely reflect the timing of certain cash receipts and expenditures. Adjusted cash flow from operations was $18,274,492 for the year ended August 31, 2012, compared $6,346,800 for the year ended August 31, 2011. The improvement of $11,927,692 under that measure is closely correlated to, and primarily explained by, increased revenues of $14,967,545 less increased operating costs of $6,437,497. The timing of cash receipts and payments explains $2,977,610 of the variance in the measure.

The cash flow statement reports actual cash expenditures for capital expenditures, which differs from total capital expenditures on a full accrual basis. Specifically, cash paid for acquisition of property and equipment as reflected in the statement of cash flows excludes non-cash capital expenditures and includes an adjustment (plus or minus) to reflect the timing of when the capital expenditure obligations are incurred and when the actual cash payment is made. On a full accrual basis, capital expenditures totaled $49,730,946, $47,237,827 and $12,888,373 for the years ended August 31, 2012, 2011 and 2010, respectively, compared to cash payments of $46,751,260, $30,247,327 and $9,152,175, respectively.

A reconciliation of the differences is summarized in the following table:

	Year Ended August 31,		
	2012	2011	2010
Cash payments	$ 46,751,260	$ 30,247,327	$ 9,152,175
Accrued costs, beginning of period	(4,967,368)	(3,466,439)	—
Accrued costs, end of period	5,732,658	4,967,368	3,466,439
Properties acquired in exchange for common stock	1,985,381	9,938,487	16,645
Properties acquired in exchange for note payable	—	5,200,000	—
Sales of properties	(71,251)	—	—
Asset retirement obligation	300,226	351,084	253,114
Capital expenditures	$ 49,730,946	$ 47,237,827	$ 12,888,373

During the fiscal year ended August 31, 2012, we engaged in drilling or completion activities on 70 wells. Most of our capital expenditures for the fiscal year ended August 31, 2012, represent drilling and completion cost on wells on which production commenced during the year. In addition, we incurred costs of $9.1 million on the acquisition of mineral leases, $2.0 million of which were acquired in exchange for our common stock.

Our primary need for cash for the fiscal year ending August 31, 2013, will be to fund our drilling and acquisition programs. Under the updated plans for our 2013 capital budget, we estimate capital expenditures of approximately $82 million for additional drilling, participating in drilling, and acquiring properties. We increased the budget from $55 million in connection with the acquisition of assets from Orr Energy LLC ("Orr") for cash payment of $30 million. As an operator, we plan to spend approximately $15 million to drill 25 vertical wells and approximately $17 million to drill 4 horizontal wells. An additional $13.5 million has been estimated as our portion of the cost of vertical and horizontal wells in which we will participate as a non-operator. We also plan recompletion costs approximating $1.5 million on 10 wells that indicate good potential for additional hydraulic stimulation. We allocated $5 million for the acquisition of undeveloped acreage. Our capital expenditure plans described herein represent cash payments, and exclude assets acquired in exchange for common stock. The proposed acquisition of assets from Orr anticipates partial payment in shares of common stock with a value of $12 million. Our capital expenditure estimate is subject to adjustment for drilling success, acquisition opportunities, operating cash flow, and available capital resources.

On October 23, 2012, we entered into an agreement to acquire developed and undeveloped oil and gas properties in the D-J Basin. Closing of the transaction is expected to occur before December 31, 2012. The purchase price for these oil and gas properties is expected to be $42 million, consisting of cash and restricted shares of Synergy's common stock.

Contractual Commitments

The following table summarizes our contractual obligations as of August 31, 2012:

	Less than One Year	One to Three Years	Three to Five Years	Total
Rig Contract[1]	$ 5,300,000	$ —	—	$ 5,300,000
Revolving credit facility	—	3,000,000	—	3,000,000
Operating Leases	100,000	—	—	100,000
Employment Agreements	630,000	105,000	—	735,000
Total	$ 6,030,000	$ 3,105,000	—	$ 9,135,000

1 As of August 31, 2012, we had agreed with Ensign United States Drilling, Inc. to use a drilling rig through December 31, 2012. Total payments due to Ensign will depend upon a number of variables, including the number of wells drilled, the target formations, and other technical details. We estimate that the total commitment for the four month period will approximate $5.3 million for the drilling of approximately 25 wells.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements that have or are reasonable likely to have a current or future material effect on our financial condition, changes in financial condition, results of operations, liquidity or capital resources.

Non-GAAP Financial Measures

We use "adjusted cash flow from operations" and "adjusted EBITDA," non-GAAP financial measures, for internal managerial purposes, when evaluating period-to-period comparisons. These measures are not measures of financial performance under U.S. GAAP and should be considered in addition to, not as a substitute for, cash flows from operations, investing, or financing activities, nor as a liquidity measure or indicator of cash flows reported in accordance with U.S. GAAP. The non-GAAP financial measures that we use may not be comparable to measures with similar titles reported by other companies. Also, in the future, we may disclose different non-GAAP financial measures in order to help our investors more meaningfully evaluate and compare our future results of operations to our previously reported results of operations. We strongly encourage investors to review our financial statements and publicly filed reports in their entirety and to not rely on any single financial measure.

See *Reconciliation of Non-GAAP Financial Measures* below for a detailed description of these measures as well as a reconciliation of each to the nearest U.S. GAAP measure.

Reconciliation of Non-GAAP Financial Measures

Adjusted cash flow from operations. We define adjusted cash flow from operations as the cash flow earned or incurred from operating activities without regard to the collection or payment of associated receivables and payables. We believe it is important to consider adjusted cash flow from operations as well as cash flow from operations, as we believe it often provides more transparency into what drives the changes in our operating trends, such as production, prices, operating costs, and related operational factors, without regard to whether the earned or incurred item was collected or paid during the period. We also use this measure because the collection of our receivables or payment of our obligations has not been a significant issue for our business, but merely a timing issue from one period to the next.

Adjusted EBITDA. We define adjusted EBITDA as net income (loss) plus interest expense, net of interest income, income taxes, stock based compensation, and depreciation, depletion and amortization for the period plus/minus the change in fair value of our derivative conversion liability. We believe adjusted EBITDA is relevant because it is a measure of cash available to fund our capital expenditures and service our debt and is a metric used by some industry analysts to provide a comparison of our results with our peers. The following table presents a reconciliation of each of our non-GAAP financial measures to its nearest GAAP measure.

	Year Ended August 31,		
	2012	2011	2010
Adjusted cash flow from operations:			
Net cash provided by operating activities	$ 21,252,102	$ 7,916,308	$ (2,443,059)
Changes in assets and liabilities	(2,977,610)	(1,569,508)	2,397,223
Adjusted cash flow from operations	$ 18,274,492	$ 6,346,800	$ (45,836)
Adjusted EBITDA:			
Net income (loss)	$ 12,123,942	$ (11,600,158)	$ (10,794,172)
Interest expense and related items, net	(37,451)	4,191,169	2,334,190
Change in fair value of derivative conversion liability	—	10,229,229	7,678,457
Provision for income tax	(332,000)	—	—
Depletion	5,837,788	2,743,441	692,274
Depreciation and amortization	171,722	94,866	9,126
Stock based compensation	473,040	627,486	582,233
Adjusted EBITDA	$ 18,237,041	$ 6,286,033	$ 502,108

Trend and Outlook

During the past several months, the gas gathering system in the Wattenberg Field has been unable to gather all the gas that could be produced. Production from new wells, particularly new horizontal wells, has strained the capacity of the system that gathers natural gas and associated liquids. The additional supply of gas creates elevated line pressure in the pipeline. When we are unable to deliver all of our gas into the pipeline, the production of oil and liquids are simultaneously restricted.

Several corrective measures are underway. DCP Midstream Partners, our third party provider of gathering, processing and transportation facilities, is rapidly expanding their capacity. DCP is creating a "super system" in Weld County of a broad network of gathering and processing facilities that afford significant optionality and flexibility, which enables DCP to optimize its processing capacity. A significant improvement in the system will occur in 2013, when a new processing plant in LaSalle, Colorado comes on line. In addition to substantially increasing capacity, DCP will improve reliability by extending the high pressure gathering system grid connected to its processing plants. Other gas gathering providers have announced similar initiatives to improve the infrastructure.

The recently announced Front Range Pipeline will also help producers in the D-J Basin maximize the value of their NGL production by providing connectivity to the premium Mont Belvieu, TX market. DCP, Enterprise Products Partners and Anadarko Petroleum are building an interstate NGL pipeline that will originate in Weld County, Colorado. Initial capacity on Front Range is expected to be 150,000 bpd, which can be expanded to approximately 230,000 bpd. Connectivity to Mont Belvieu includes transportation via the recently announced Texas Express Pipeline, in which DCP has a vested interest as a 10% owner. The Texas Express Pipeline is expected to be completed by the second quarter of 2013, and Front Range Pipeline is expected to be in service by the fourth quarter 2013. We expect these third party capital projects to accommodate our and other producer's throughput, including anticipated aggressive growth in the basin.

For our part, we have begun installing improved equipment, including compressors, to strategic pad locations. We are also accelerating our previously planned maintenance and modification expenditures on certain wells to improve volume output.

Other factors that will most significantly affect our results of operations include (i) activities on properties that we operate, (ii) the marketability of our production, (iii) our ability to satisfy our substantial capital requirements, (iv) completion of acquisitions of additional properties and reserves, (v) competition from larger companies, and (vi) prices for oil and gas. Our revenues will also be significantly impacted by our ability to maintain or increase oil or gas production through exploration and development activities.

It is expected that our principal source of cash flow will be from the production and sale of oil and gas reserves, which are depleting assets. Cash flow from the sale of oil and gas production depends upon the quantity of production and the price obtained for the production. An increase in prices will permit us to finance our operations to a greater extent with internally generated funds, may allow us to obtain equity financing more easily or on better terms, and lessens the difficulty of obtaining debt financing. However, price increases heighten the competition for oil and gas prospects, increase the costs of exploration and development, and, because of potential price declines, increase the risks associated with the purchase of producing properties during times that prices are at higher levels.

A decline in oil and gas prices (i) will reduce our cash flow which in turn will reduce the funds available for exploring for and replacing oil and gas reserves, (ii) will potentially reduce our current LOC borrowing base capacity and increase the difficulty of obtaining equity and debt financing and worsen the terms on which such financing may be obtained, (iii) will reduce the number of oil and gas prospects which have reasonable economic terms, (iv) may cause us to permit leases to expire based upon the value of potential oil and gas reserves in relation to the costs of exploration, and (v) may result in marginally productive oil and gas wells being abandoned as non-commercial. However, price declines reduce the competition for oil and gas properties and correspondingly reduce the prices paid for leases and prospects.

Other than the foregoing, we do not know of any trends, events or uncertainties that will have had or are reasonably expected to have a material impact on our sales, revenues or expenses.

Critical Accounting Policies

The discussion and analysis of our financial condition and results of operations are based upon our financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States.

We provide expanded discussion of our more significant accounting policies, estimates and judgments below. We believe these accounting policies reflect our more significant estimates and assumptions used in preparation of our financial statements. See Note 1 of the Notes to the Financial Statements for a detailed discussion of the nature of our accounting practices and additional accounting policies and estimates made by management.

Oil and Gas Sales: We derive revenue primarily from the sale of produced crude oil and natural gas. Revenues from production on properties in which we share an economic interest with other owners are recognized on the basis of our interest. Revenues are reported on a gross basis for the amounts received before taking into account production taxes and transportation costs, which are reported as separate expenses. Revenue is recorded and receivables are accrued using the sales method, which occurs in the month production is delivered to the purchaser, at which time ownership of the oil is transferred to the purchaser. Payment is generally received between thirty and ninety days after the date of production. Provided that reasonable estimates can be made, revenue and receivables are accrued to recognize delivery of product to the purchaser. Differences between estimates and actual volumes and prices, if any, are adjusted upon final settlement.

Oil and Gas Reserves: Oil and gas reserves represent theoretical, estimated quantities of crude oil and natural gas which geological and engineering data estimate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. There are numerous uncertainties inherent in estimating oil and gas reserves and their values, including many factors beyond our control. Accordingly, reserve estimates are different from the future quantities of oil and gas that are ultimately recovered and the corresponding lifting costs associated with the recovery of these reserves.

The determination of depletion and amortization expenses, as well as the ceiling test calculation related to the recorded value of our oil and natural gas properties, is highly dependent on estimates of proved oil and natural gas reserves.

Oil and Gas Properties: We use the full cost method of accounting for costs related to its oil and gas properties. Accordingly, all costs associated with acquisition, exploration, and development of oil and gas reserves (including the costs of unsuccessful efforts) are capitalized into a single full cost pool. These costs include land acquisition costs, geological and geophysical expense, carrying charges on non-producing properties, costs of drilling and overhead charges directly related to acquisition and exploration activities. Under the full cost method, no gain or loss is recognized upon the sale or abandonment of oil and gas properties unless non-recognition of such gain or loss would significantly alter the relationship between capitalized costs and proved oil and gas reserves.

Capitalized costs of oil and gas properties are depleted using the unit-of-production method based upon estimates of proved reserves. For depletion purposes, the volume of petroleum reserves and production is converted into a common unit of measure at the energy equivalent conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil. Investments in unevaluated properties and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. If the results of an assessment indicate that the properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized.

Asset Retirement Obligations (“ARO”)**:** We are subject to legal and contractual obligations to reclaim, remediate, or otherwise restore properties at the time the asset is permanently removed from service. Calculation of an ARO requires estimates about several future events, including the life of the asset, the costs to remove the asset from service, and inflation factors. The ARO is initially estimated based upon discounted cash flows over the life of the asset and is accreted to full value over time using our credit adjusted risk free interest rate. Estimates are periodically reviewed and adjusted to reflect changes.

The present value of a liability for the ARO is initially recorded when it is incurred if a reasonable estimate of fair value can be made. This is typically when a well is completed or an asset is placed in service. When the ARO is initially recorded, we capitalize the cost (asset retirement cost or "ARC") by increasing the carrying value of the related asset. ARCs related to wells are capitalized to the full cost pool and subject to depletion. Over time, the liability increases for the change in its present value (accretion of ARO), while the capitalized cost decreases over the useful life of the asset, recognized as depletion.

Stock-Based Compensation: We recognize all equity-based compensation as stock-based compensation expense, included in general and administrative expenses, based on the fair value of the compensation measured at the grant date. The expense is recognized over the vesting period of the grant.

Income Taxes: Deferred income taxes are recorded for timing differences between items of income or expense reported in the financial statements and those reported for income tax purposes using the asset/liability method of accounting for income taxes. Deferred income taxes and tax benefits are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases, and for tax loss and credit carry-forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. We provide for deferred taxes for the estimated future tax effects attributable to temporary differences and carry-forwards when realization is more likely than not. If we conclude that it is more likely than not that some portion, or all, of the net deferred tax asset will not be realized, the balance of net deferred tax assets is reduced by a valuation allowance.

We consider many factors in our evaluation of deferred tax assets, including the following sources of taxable income that may be available under the tax law to realize a portion or all of a tax benefit for deductible timing differences and carry-forwards:

- Future reversals of existing taxable temporary differences,
- Taxable income in prior carry back years, if permitted,
- Tax planning strategies, and
- Future taxable income exclusive of reversing temporary differences and carry- forwards.

Recent Accounting Pronouncements

We evaluate the pronouncements of various authoritative accounting organizations to determine the impact of new pronouncements on U.S. GAAP and their impact on us.

In December 2011, the FASB issued ASU 2011-11, Balance Sheet (Topic 210): *Disclosures about Offsetting Assets and Liabilities.* This ASU requires us to disclose both net and gross information about assets and liabilities that have been offset, if any, and the related arrangements. The disclosures under this new guidance are required to be provided retrospectively for all comparative periods presented. We are required to implement this guidance effective for the first quarter of fiscal 2014 and do not expect the adoption of ASU 2011-11 to have a material impact on our financial statements.

Various other accounting standards updates recently issued, most of which represented technical corrections to the accounting literature or were applicable to specific industries, and are not expected to a have a material impact on our financial position, results of operations or cash flows.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISKS

Commodity Risk - Our primary market risk exposure results from the price we receive for our oil and natural gas production. We do not currently engage in any commodity hedging activities, although we may do so in the future. Realized commodity pricing for our production is primarily driven by the prevailing worldwide price for oil and spot prices applicable to natural gas. Pricing for oil and natural gas production has been volatile and unpredictable in recent years, and we expect this volatility to continue in the foreseeable future. The prices we receive for production depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable commodity index price.

Interest Rate Risk - At August 31, 2012, we had debt outstanding under our bank credit facility totaling $3,000,000. Interest on our bank credit facility accrues at the greater of 3.25% or the prime rate, which was also 3.25% at August 31, 2012. While we are currently incurring interest at the floor of 3.25%, we are exposed to interest rate risk on the bank credit facility if the prime rate exceeds the floor. The agreement provides an interest rate index of LIBOR plus 2.5% at our option. If interest rates increase, our interest expense would increase and our available cash flow would decrease. Hypothetically, a 1.0% increase in the prime rate for the year ended August 31, 2012 would have resulted in an estimated $33,000 increase in interest expense for the year ended August 31, 2012.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

See the financial statements and accompanying notes included with 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

An evaluation was carried out under the supervision and with the participation of our management, including our President and Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report on Form 10-K. Disclosure controls and procedures are procedures designed with the objective of ensuring that information required to be disclosed in our reports filed under the Securities Exchange Act of 1934, such as this Form 10-K, is recorded, processed, summarized and reported, within the time period specified in the Securities and Exchange Commission’s rules and forms, and that such information is accumulated and is communicated to our management, including our President and Chief Executive Officer as well as our Chief Financial Officer to allow timely decisions regarding required disclosure.

Based on that evaluation, our management concluded that, as of August 31, 2012, our disclosure controls and procedures were effective.

Changes in Internal Control Over Financial Reporting

During the fourth quarter of fiscal year ended August 31, 2012, we took measures to bolster our internal control processes pertaining to financial reporting. Such measures include additional procedures and personnel to ensure accuracy in our financial reporting.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting. As defined by the Securities and Exchange Commission, internal control over financial reporting is a process designed by, or under the supervision of two key personnel, our President and Chief Executive Officer and our Chief Financial Officer and implemented by our Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements in accordance with U.S. generally accepted accounting principles.

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.

Ed Holloway, our President and Chief Executive Officer, and Frank L. Jennings, our Chief Financial Officer, evaluated the effectiveness of our internal control over financial reporting as of August 31, 2012 based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, or the COSO Framework. Management’s assessment included an evaluation of the design of our internal control over financial reporting and testing of the operational effectiveness of those controls. Based on this evaluation, management concluded that our internal control over financial reporting was effective as of August 31, 2012.

Attestation Report of Registered Public Accounting Firm

The attestation report required under this Item 9A is set forth under the caption "Report of Independent Registered Public Accounting Firm", which is included with the financial statements and supplemental data required by Item 8.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Our officers and directors are listed below. Our directors are generally elected at our annual shareholders' meeting and hold office until the next annual shareholders' meeting or until their successors are elected and qualified. Our executive officers are elected by our directors and serve at their discretion.

Name	Age	Position
Edward Holloway	60	President, Chief Executive Officer and Director
William E. Scaff, Jr.	55	Vice President, Secretary, Treasurer and Director
Frank L. Jennings	61	Chief Financial Officer
Rick A. Wilber	65	Director
Raymond E. McElhaney	56	Director
Bill M. Conrad	56	Director
R.W. Noffsinger, III	38	Director
George Seward	62	Director

Edward Holloway – Mr. Holloway has been an officer and director since September 2008 and was an officer and director of our predecessor between June 2008 and September 2008. Mr. Holloway co-founded Cache Exploration Inc., an oil and gas exploration and development company. In 1987, Mr. Holloway sold the assets of Cache Exploration to LYCO Energy Corporation. He rebuilt Cache Exploration and sold the entire company to Southwest Production a decade later. In 1997, Mr. Holloway co-founded, and since that date has co-managed, Petroleum Management, LLC, a company engaged in the exploration, operations, production and distribution of oil and natural gas. In 2001, Mr. Holloway co-founded, and since that date has co-managed, Petroleum Exploration and Management, LLC, a company engaged in the acquisition of oil and gas leases and the production and sale of oil and natural gas. Mr. Holloway holds a degree in Business Finance from the University of Northern Colorado and is a past president of the Colorado Oil and Gas Association.

William E. Scaff, Jr. – Mr. Scaff has been an officer and director since September 2008 and was an officer and director of our predecessor between June 2008 and September 2008. Between 1980 and 1990, Mr. Scaff oversaw financial and credit transactions for Dresser Industries, a Fortune 50 oilfield equipment company. Immediately after serving as a regional manager with TOTAL Petroleum between 1990 and 1997, Mr. Scaff co-founded, and since that date co-managed, Petroleum Management, LLC, a company engaged in the exploration, operations, production and distribution of oil and natural gas. In 2001, Mr. Scaff co-founded, and since that date has co-managed, Petroleum Exploration and Management, LLC, a company engaged in the acquisition of oil and gas leases and the production and sale of oil and natural gas. Mr. Scaff holds a degree in Finance from the University of Colorado.

Frank L. Jennings – Mr. Jennings began his service as our Chief Financial Officer on a part-time basis in June 2007. In March 2011, he joined us on a full-time basis. From 2001 until 2011, Mr. Jennings was an independent consultant providing financial accounting services, primarily to smaller public companies. From 2006 until 2011, he also served as the Chief Financial Officer of Gold Resource Corporation (AMEX:GORO). From 2000 to 2005, he served as the Chief Financial Officer and a director of Global Casinos, Inc., a publicly traded corporation, and from 1994 to 2001 he served as Chief Financial Officer of American Educational Products, Inc. (NASDAQ:AMEP), before it was purchased by Nasco International. After his graduation from Austin College with a degree in economics and from Indiana University with an MBA in finance, he joined the Houston office of Coopers & Lybrand. He also spent four years as the manager of internal audit for The Walt Disney Company.

Rick A. Wilber – Mr. Wilber has been one of our directors since September 2008. Since 1984, Mr. Wilber has been a private investor in, and a consultant to, numerous development stage companies. In 1974, Mr. Wilber was co-founder of Champs Sporting Goods, a retail sporting goods chain, and served as its President from 1974-1984. He has been a Director of Ultimate Software Group Inc. since October 2002 and serves as a member of its audit and compensation committees. Mr. Wilber was a director of Ultimate Software Group between October 1997 and May 2000. He served as a director of Royce Laboratories, Inc., a pharmaceutical concern, from 1990 until it was sold to Watson Pharmaceuticals, Inc. in April 1997 and was a member of its compensation committee.

Raymond E. McElhaney – Mr. McElhaney has been one of our directors since May 2005, and prior to the acquisition of Predecessor Synergy was our President and Chief Executive Officer. Mr. McElhaney began his career in the oil and gas industry in 1983 as founder and President of Spartan Petroleum and Exploration, Inc. Mr. McElhaney also served as a chairman and secretary of Wyoming Oil & Minerals, Inc., a publicly traded corporation, from February 2002 until 2005. From 2000 to 2003, he served as vice president and secretary of New Frontier Energy, Inc., a publicly traded corporation. McElhaney is a co-founder of MCM Capital Management Inc., a privately held financial management and consulting company formed in 1990 and has served as its president of that company since inception.

Bill M. Conrad – Mr. Conrad has been one of our directors since May 2005 and prior to the acquisition of Predecessor Synergy was our Vice President and Secretary. Mr. Conrad has been involved in several aspects of the oil and gas industry over the past 20 years. From February 2002 until June 2005, Mr. Conrad served as president and a director of Wyoming Oil & Minerals, Inc., and from 2000 until April 2003, he served as vice president and a director of New Frontier Energy, Inc. Since June 2006, Mr. Conrad has served as a director of Gold Resource Corporation, a publicly traded corporation engaged in the mining industry. In 1990, Mr. Conrad co-founded MCM Capital Management Inc. and has served as its vice president since that time.

R.W. "Bud" Noffsinger, III – Mr. Noffsinger was appointed as one of our directors in September 2009. Mr. Noffsinger has been the President/ CEO of RWN3 LLC, a company involved with investment securities, since February 2009. Previously, Mr. Noffsinger was the President (2005 to 2009) and Chief Credit Officer (2008 to 2009) of First Western Trust Bank in Fort Collins, Colorado. Prior to his association with First Western, Mr. Noffsinger was a manager with Centennial Bank of the West (now Guaranty Bank and Trust). Mr. Noffsinger's focus at Centennial was client development and lending in the areas of commercial real estate, agriculture and natural resources. Mr. Noffsinger is a graduate of the University of Wyoming and holds a Bachelor of Science degree in Economics with an emphasis on natural resources and environmental economics.

George Seward – Mr. Seward was appointed as one of our directors on July 8, 2010. Mr. Seward cofounded Prima Energy in 1980 and served as its Secretary until 2004, when Prima was sold to Petro-Canada for $534,000,000. At the time of the sale, Prima had 152 billion cubic feet of proved gas reserves and was producing 55 million cubic feet of gas daily from wells in the D-J Basin in Colorado and the Powder River Basin of Wyoming and Utah. Since March 2006 Mr. Seward has been the President of Pocito Oil and Gas, a limited production company, with operations in northeast Colorado, southwest Nebraska and Barber County, Kansas. Mr. Seward has also operated a diversified farming operation, raising wheat, corn, pinto beans, soybeans and alfalfa hay in southwestern Nebraska and northeast Colorado, since 1982.

We believe Messrs. Holloway, Scaff, McElhaney, Conrad and Seward are qualified to act as directors due to their experience in the oil and gas industry. We believe Messrs. Wilber and Noffsinger are qualified to act as directors as result of their experience in financial matters.

Rick Wilber, Raymond McElhaney, Bill Conrad and R.W. Noffsinger, are considered independent as that term is defined Section 803.A of the NYSE MKT Rules.

The members of our compensation committee are Rick Wilber, Raymond McElhaney, Bill Conrad, and R.W. Noffsinger. The members of our Audit Committee are Raymond McElhaney, Bill Conrad and R.W. Noffsinger. Mr. Noffsinger acts as the financial expert for the Audit Committee of our board of directors.

We have adopted a Code of Ethics applicable to all employees.

ITEM 11. EXECUTIVE COMPENSATION

The following table shows the compensation paid or accrued to our executive officers during each of the three years ended August 31, 2012.

Name and Principal Position	Fiscal Year		Salary [1]	Bonus [2]	Stock Awards [3]	Option Awards [4]	All Other Compensation [5]		Total
Ed Holloway,	2012	$	300,000	100,000	—	—	9,800	$	409,800
President and Chief	2011	$	300,000	100,000	—	—	9,800	$	409,800
Executive Officer	2010	$	175,000	—	—	—	—	$	175,000
William E. Scaff, Jr.,	2012	$	300,000	100,000	—	—	9,800	$	409,800
Vice President, Secretary	2011	$	300,000	100,000	—	—	9,800	$	409,800
and Treasurer	2010	$	175,000	—	—	—	—	$	175,000
Frank L Jennings,	2012	$	180,000	—	—	—	5,400	$	185,400
Chief Financial Officer	2011	$	87,391	—	220,000	404,352	—	$	711,743
	2010	$	106,225	—	—	—	—	$	106,225

1 The dollar value of base salary (cash and non-cash) earned.
2 The dollar value of bonus (cash and non-cash) earned.
3 The fair value of stock issued for services computed in accordance with ASC 718 on the date of grant.
4 The fair value of options granted computed in accordance with ASC 718 on the date of grant.
5 All other compensation received that we could not properly report in any other column of the table.

The compensation to be paid to Mr. Holloway, Mr. Scaff and Mr. Jennings will be based upon their employment agreements, which are described below. All material elements of the compensation paid to these officers is discussed below.

On June 11, 2008, we signed employment agreements with Ed Holloway and William E. Scaff Jr. Each employment agreement provided that the employee would be paid a monthly salary of $12,500 and required the employee to devote approximately 80% of his time to our business. The employment agreements expired on June 1, 2010.

On June 1, 2010, we entered into new employment agreements with Mr. Holloway and Mr. Scaff. The new employment agreements, which expire on May 31, 2013, provide that we pay Mr. Holloway and Mr. Scaff each a monthly salary of $25,000 and require both Mr. Holloway and Mr. Scaff to devote approximately 80% of their time to our business. In addition, for every 50 wells that begin producing oil and/or gas after June 1, 2010, whether as the result of our successful drilling efforts or acquisitions, we will issue, to each of Mr. Holloway and Mr. Scaff, a cash payment of $100,000 or shares of common stock in an amount equal to $100,000 divided by the average closing price of our common stock for the 20 trading days prior to the date the 50th well begins producing.

On June 23, 2011 our directors approved an employment agreement with Frank L. Jennings, our Chief Financial Officer. The employment agreement provides that we will pay Mr. Jennings a monthly salary of $15,000 and issue to Mr. Jennings:

- 50,000 shares of our restricted common stock; and
- options to purchase 150,000 shares of our common stock. The options are exercisable at a price of $4.40 per share, vest over three years in 50,000 share increments beginning March 6, 2012, and expire on March 7, 2021.

The employment agreement expires on March 7, 2014 and requires Mr. Jennings to devote all of his time to our business.

If Mr. Jennings resigns within 90 days of a relocation (or demand for relocation) of his place of employment to a location more than 35 miles from his then current place of employment, the employment agreement will be terminated and Mr. Jennings will be paid the salary provided by the employment agreement through the date of termination and the unvested portion of any stock options held by Mr. Jennings will vest immediately.

In the event there is a change in the control, the employment agreement allows Mr. Jennings to resign from his position and receive a lump-sum payment equal to 12 months' salary. In addition, the unvested portion of any stock options held by Mr. Jennings will vest immediately. For purposes of the employment agreement, a change in the control means: (1) our merger with another entity if after such merger our shareholders do not own at least 50% of the voting capital stock of the surviving corporation; (2) the sale of substantially all of our assets; (3) the acquisition by any person of more than 50% of our common stock; or (4) a change in a majority of our directors which has not been approved by our incumbent directors.

The employment agreements mentioned above, will terminate upon the employee's death, or disability or may be terminated by us for cause. If the employment agreement is terminated for any of these reasons, the employee, or his legal representatives as the case may be, will be paid the salary provided by the employment agreement through the date of termination.

For purposes of the employment agreements, “cause” is defined as:

(i) the conviction of the employee of any crime or offense involving, or of fraud or moral turpitude, which significantly harms us;

(ii) the refusal of the employee to follow the lawful directions of our board of directors;

(iii) the employee’s negligence which shows a reckless or willful disregard for reasonable business practices and significantly harms us; or

(iv) a breach of the employment agreement by the employee.

Executive officer compensation, as provided above, is structured to be competitive both in its design and in the total compensation offered. The Compensation Committee of the Board of Directors determines the compensation of the Company’s officers. The Committee’s philosophy on officer compensation is to align executive and shareholder interests. The philosophy’s objective is to provide fair compensation based upon the individual’s position, experience and individual performance.

The Company’s current policy is that the various elements of the compensation package are not interrelated in that gains or losses from past equity incentives are not factored into the determination of other compensation.

A goal of the compensation program is to provide executive officers with a reasonable level of security through base salary and benefits. The Company wants to ensure that the compensation programs are appropriately designed to encourage executive officer retention and motivation to create shareholder value. The Compensation Committee believes that the Company’s stockholders are best served when the Company can attract and retain talented executives by providing compensation packages that are competitive but fair.

The key components of the Company’s executive compensation program include annual base salaries and long-term incentive compensation consisting of stock options. It is the Company’s policy to target compensation (i.e., base salary, stock option grants and other benefits) at approximately the median of comparable companies in the oil and gas exploration and development industry. Accordingly, data on compensation practices followed by other companies in the oil and gas exploration and development industry is considered.

Base salaries generally have been targeted to be competitive when compared to the salary levels of persons holding similar positions in other oil and gas exploration and development companies and other publicly traded companies of comparable size.

Stock option grants help to align the interests of the Company’s officers with those of its shareholders. Options grants are made under the Company’s Stock Option Plan.

The Company believes that grants of stock options:

- Enhance the link between the creation of shareholder value and long-term executive incentive compensation;
- Provide focus, motivation and retention incentive; and
- Provide competitive levels of total compensation.

The Company's long-term incentive program consists exclusively of periodic grants of stock options with an exercise price equal to the fair market value of the Company's common stock on the date of grant. Decisions made regarding the timing and size of option grants take into account the performance of both the Company and the employee, "competitive market" practices, and the size of the option grants made in prior years. The weighting of these factors varies and is subjective.

In addition to cash and equity compensation programs, executive officers participate in the health insurance programs available to the Company's other employees.

All executive officers are eligible to participate in the Company's 401(k) plan on the same basis as all other employees. The Company matches participant's contribution in cash, not to exceed 4% of the participant's total compensation.

We had a consulting agreement with Ray McElhaney and Bill Conrad which provided that Mr. McElhaney and Mr. Conrad would render, on a part-time basis, consulting services pertaining to corporate acquisitions and development. For these services, Mr. McElhaney and Mr. Conrad were paid a monthly consulting fee of $5,000. The consulting agreement expired on September 15, 2009.

Employee Pension, Profit Sharing or other Retirement Plans. Effective November 1, 2010, we adopted a defined contribution retirement plan, qualifying under Section 401(k) of the Internal Revenue Code and covering substantially all of our employees. We match participant's contributions in cash, not to exceed 4% of the participant's total compensation. Other than this 401(k) Plan, we do not have a defined benefit pension plan, profit sharing or other retirement plan.

Stock Option and Bonus Plans

We have three stock award plans: (i) a 2011 non-qualified stock option plan, (ii) a 2011 incentive stock option plan, and (iii) a 2011 stock bonus plan. The plans adopted during 2011 replaced a non-qualified stock option plan and a stock bonus plan originally adopted during 2005 (the "2005 Plans"). No additional options or shares will be issued under the 2005 Plans. Each plan authorizes the issuance of shares of our common stock to persons that exercise options granted pursuant to the Plan. Our employees, directors, officers, consultants and advisors are eligible to received such awards, provided that bona fide services be rendered by such consultants or advisors and such services must not be in connection with promoting our stock or the sale of securities in a capital-raising transaction. The option exercise price is determined by our directors, though generally is based upon the closing market price of our shares on the date of grant.

Summary. The following is a summary of options granted or shares issued pursuant to the Plans as of October 15, 2012. Each option represents the right to purchase one share of our common stock.

Name of Plan	Total Shares Reserved Under Plans	Reserved for Outstanding Options	Shares Issued as Stock Bonus	Remaining Options/Shares Under Plans
2011 Non-Qualified Stock Option Plan	2,000,000	795,000	—	1,205,000
2011 Incentive Stock Option Plan	2,000,000	—	—	2,000,000
2011 Stock Bonus Plan	2,000,000	—	5,000	1,995,000

Options

In connection with the acquisition of a corporation in 2008, we issued options to the persons shown below in exchange for options previously issued by that corporation. The terms of the options we issued are identical to the terms of the previously issued options. The options were not granted pursuant to our 2005 Plans. As of October 15, 2012, none of these options have been exercised.

Name	Grant Date	Shares Issuable Upon Exercise of Options	Exercise Price	Expiration Date
Ed Holloway [1]	9/10/08	1,000,000	$ 1.00	6/11/13
William E. Scaff, Jr. [2]	9/10/08	1,000,000	$ 1.00	6/11/13
Ed Holloway [1]	9/10/08	1,000,000	$ 10.00	6/11/13
William E. Scaff, Jr. [2]	9/10/08	1,000,000	$ 10.00	6/11/13

1 Options are held of record by a limited liability company controlled by Mr. Holloway.
2 Options are held of record by a limited liability company controlled by Mr. Scaff.

The following table shows information concerning our outstanding options as of October 15, 2012.

Name	Shares underlying unexercised Option which are: Exercisable	Unexercisable	Exercise Price	Expiration Date
Ed Holloway	1,000,000	—	$ 1.00	6/11/13
William E. Scaff, Jr.	1,000,000	—	$ 1.00	6/11/13
Ed Holloway	1,000,000	—	$ 10.00	6/11/13
William E. Scaff, Jr.	1,000,000	—	$ 10.00	6/11/13
Frank L. Jennings	50,000	100,000	$ 4.40	3/7/21
Employees	220,500[1]	544,500[1]	[1]	[1]

1 Options were issued to several employees pursuant to our Non-Qualified Stock Option Plan. The exercise price of the options varies between $2.40 and $4.40 per share. The options expire at various dates between December 2018 and August, 2022.

The following table shows the weighted average exercise price of the outstanding options granted pursuant to our Non-Qualified Stock Option Plan or otherwise as of August 31, 2012.

Plan Category	Available Securities to be Issued Upon Exercise of Outstanding Options	Weighted-Average Exercise Price of Outstanding Options
Non-Qualified Stock Option Plan	915,000	$ 5.09
Other Options	4,000,000	$ 5.50

Compensation of Directors During Year Ended August 31, 2012

Name	Fees Earned or Paid in Cash	Stock Awards [1]	Option Awards [2]	Total
Rick Wilber	$ 22,000	—	—	$ 22,000
Raymond McElhaney	32,000	—	—	32,000
Bill Conrad	30,500	—	—	30,500
R.W. Noffsinger	27,500	—	—	27,500
George Seward	22,500	—	—	22,500
	$ 134,500	—	—	$ 134,500

[1] The fair value of stock issued for services computed in accordance with ASC 718.
[2] The fair value of options granted computed in accordance with ASC 718 on the date of grant.

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

The following table shows, as of October 15, 2012, information with respect to those persons owning beneficially 5% or more of our common stock and the number and percentage of outstanding shares owned by each of our directors and officers and by all officers and directors as a group. Unless otherwise indicated, each owner has sole voting and investment powers over his shares of common stock.

Name	Number of Shares [1]	Percent of Class [2]
Ed Holloway	4,760,909 [3]	8.9%
William E. Scaff, Jr.	4,760,909 [4]	8.9%
Frank L. Jennings	128,000	0.2%
Rick A. Wilber	808,915	1.6%
Raymond E. McElhaney	507,725	1.0%
Bill M. Conrad	494,225	1.0%
R.W. Noffsinger, III	538,425	1.0%
George Seward	1,635,161	3.1%
Wayne L. Laufer	3,381,250	6.5%
All officers and directors as a group (8 persons)	13,634,269	23.9%

[1] Share ownership includes shares issuable upon the exercise of options and warrants, all of which are exercisable on or by December 15, 2012, held by the persons listed below.

Name	Shares Issuable Upon Exercise of Options and Warrants	Option or Warrant Exercise Price	Expiration Date
Ed Holloway	1,000,000	$ 1.00	6/11/2013
Ed Holloway	1,000,000	$ 10.00	6/11/2013
William E. Scaff, Jr.	1,000,000	$ 1.00	6/11/2013
William E. Scaff, Jr.	1,000,000	$ 10.00	6/11/2013
Frank L. Jennings	50,000	$ 4.40	3/7/2021
Frank L. Jennings	4,000	$ 6.00	12/31/2012
Rick A. Wilber	215,000	$ 6.00	12/31/2012
Rick A. Wilber	17,000	$ 10.00	12/31/2012
Raymond E. McElhaney	262,000	$ 6.00	12/31/2012
Bill M. Conrad	247,000	$ 6.00	12/31/2012
R.W. Noffsinger, III	125,000	$ 6.00	12/31/2012
R.W. Noffsinger, III	125,000	$ 10.00	12/31/2012
George Seward	387,000	$ 6.00	12/31/2014
Wayne L. Laufer	275,000	$ 6.00	12/31/2014

[2] Computed based upon 51,562,287 shares of common stock outstanding as of October 15, 2012 plus adjustments for shares issuable upon exercise of options and warrants.

[3] Shares are held of record by various trusts and limited liability companies controlled by Mr. Holloway.

[4] Shares are held of record by various trusts and limited liability companies controlled by Mr. Scaff.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, DIRECTOR INDEPENDENCE

Any transaction between us and related parties must be approved by a majority of our disinterested directors.

Two of our officers, Ed Holloway and William Scaff, Jr., control three entities with which we have entered into agreements. These entities are Petroleum Management, LLC ("PM"), Petroleum Exploration and Management, LLC ("PEM"), and HS Land and Cattle, LLC ("HSLC").

We acquired all of the working oil and gas assets owned by PEM in a transaction that closed on May 24, 2011. In total, we acquired interests in 88 gross (40 net) oil and gas wells in the Wattenberg Field, and interests in oil and gas leases covering approximately 6,968 gross acres in the Wattenberg Field and the Eastern D-J Basin. These oil and gas interests were acquired from Petroleum Exploration and Management, LLC ("PEM"), a company owned by Ed Holloway and William E. Scaff, Jr., two of our officers, for approximately $19.0 million. The transaction was approved by the disinterested directors and by a vote of the shareholders, with Mr. Holloway and Mr. Scaff not voting. The purchase was funded with a combination of cash, restricted shares and a note payable. In November 2011, the Company utilized proceeds from the bank credit facility to repay the entire principal balance on the related party notes of $5.2 million and accrued interest summing to approximately $142,000.

In October 2010, and following the approval of our directors, we acquired oil and gas properties from PM and PEM, for approximately $1.0 million. The oil and gas properties we acquired are located in the Wattenberg Field and consisted of:

- six producing oil and gas wells,
- two shut in oil wells,
- fifteen drill sites, net 6.25 wells, and
- miscellaneous equipment.

We have a 100% working interest (80% net revenue interest) in the six producing wells and the two shut in wells.

In 2009, PM and PEM acquired the same oil and gas properties sold to us from an unrelated third party for $920,000. The difference in the price we paid for the properties and the price PM and PEM paid for the properties represents interest on the amount paid by PM and PEM for the properties, closing costs and equipment improvements.

We had a letter agreement with PM and PEM which provided us with the option to acquire working interests in oil and gas leases owned by these firms and covering lands on the D-J basin. The oil and gas leases covered 640 acres in Weld County, Colorado and, subject to certain conditions, would be transferred to us for payment of $1,000 per net mineral acre. The working interests in the leases we could acquire varied, but the net revenue interest in the leases, could not be less than 75%. Under this letter agreement, through February 2010 we acquired leases covering 640 gross (360 net) acres from PM and PEM for $360,000.

Pursuant to the terms of an Administrative Services Agreement, through June 30, 2010, PM provided us with office space and equipment storage in Platteville, Colorado, as well as secretarial, word processing, telephone, fax, email and related services for a fee of $20,000 per month. Following the termination of the Administrative Services Agreement, and since July 1, 2010, we have leased the office space and equipment storage yard from HSLC at a rate of $10,000 per month.

During the year ended August 31, 2012, we acquired oil and gas leases from George Seward, a member of our board of directors. In total, we purchased lease interests covering 61,397 gross (51,127 net) undeveloped acres, located in eastern Colorado and western Nebraska, in exchange for 188,137 shares of our common stock. Based on the market price of our common stock on the transaction dates, these acquisitions were valued at $595,785.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

For each of the three years ended August 31, 2012, 2011 and 2010, Ehrhardt Keefe Steiner & Hottman P.C. ("EKS&H") served as our independent registered public accounting firm.

	Year Ended August 31, 2012	Year Ended August 31, 2011	Year Ended August 31, 2009
Audit Fees	$ 210,000	$ 119,514	$ 72,213
Audit-Related Fees	6,671	35,993	7,500
Tax Fees	40,670	43,157	3,800
All Other Fees	—	—	—

Audit fees represent amounts billed for professional services rendered for the audit of our annual financial statements and the reviews of the financial statements included in our Form 10-Q and Form 10-K reports. Audit-related fees include amounts billed for the review of our registration statement on Form S-1. Prior to contracting with EKS&H to render audit or non-audit services, each engagement was approved by our audit committee.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

Exhibits

1.1	Purchase Agreement, dated as of December 16, 2011, by and between Synergy Resources Corporation and Northland Securities, Inc., acting severally on behalf of itself and the underwriters named in Schedule I thereto [1]
3.1.1	Articles of Incorporation[2]
3.1.2	Amendment to Articles of Incorporation[1]
3.1.3	Bylaws[2]
4.1	Form of Common Stock Certificate[1]
5.1	Opinion of Hart & Trinen, LLP[1]
10.1	Employment Agreement with Ed Holloway[3]
10.2	Employment Agreement with William E. Scaff, Jr.[3]
10.3	Administrative Services Agreement[4]
10.4	Agreement regarding Conflicting Interest Transactions[4]
10.5	Consulting Services Agreement with Raymond McElhaney and Bill Conrad [5]
10.6.1	Form of Convertible Note [5]
10.6.2	Form of Subscription Agreement [5]
10.6.3	Form of Series C Warrant [5]
10.7	Purchase and Sale Agreement with Petroleum Exploration and Management, LLC (wells, equipment and well bore leasehold assignments) [5]
10.8	Purchase and Sale Agreement with Petroleum Management, LLC (operations and leasehold) [5]
10.9	Purchase and Sale Agreement with Chesapeake Energy [5]
10.10	Lease with HS Land & Cattle, LLC [5]
10.11	Employment Agreement with Frank L. Jennings [6]

10.12 Purchase and Sale Agreement with Petroleum Exploration and Management, LLC [7]

10.13 Loan Agreement with Bank of Choice (presently known as Guarantee Bank of Colorado) [8]

10.14 Purchase and Sale Agreement with DeClar Oil & Gas, Inc. and Wolf Point Exploration, LLC [9]

10.15 Amendment to Line of Credit Agreement [10]

10.16 Amendment #2 to Loan Agreement [12]

10.17 Purchase and Sale Agreement with ORR ENERGY LLC (Weld County, Colorado oil and gas property) [12]

14 Code of Ethics (as amended) [11]

23.1 Consent of Ehrhardt Keefe Steiner & Hottman PC

31 Rule 13a-14(a) Certifications

32 Section 1350 Certifications

99 Report of Ryder Scott Company, L.P.

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[1] Incorporated by reference to the same exhibit filed with the Company's report on Form 8-K filed on December 16, 2011.

[2] Incorporated by reference to the same exhibit filed with the Company's registration statement on Form SB-2, File #333-146561.

[3] Incorporated by reference to the same exhibit filed with the Company's transition report on Form 8-K for the period ended August 31, 2008.

[4] Incorporated by reference to the same exhibit filed with the Company's transition report on Form 10-K for the year ended August 31, 2008.

[5] Incorporated by reference to the same exhibit filed with the Company's report on Form 10-K/A filed on June 3, 2011.

[6] Incorporated by reference to the same exhibit filed with the Company's report on Form 8-K filed on June 24, 2011.

[7] Incorporated by reference to Exhibit 10.12 filed with the Company's report on Form 8-K filed on August 5, 2011.

[8] Incorporated by reference to Exhibit 10.13 filed with the Company's report on Form 8-K filed on December 2, 2011.

[9] Incorporated by reference to Exhibit 10.14 filed with the Company's report on Form 8-K filed on February 23, 2012.

[10] Incorporated by reference to Exhibit 10.15 filed with the Company's report on Form 8-K filed on April 25, 2012.

[11] Incorporated by reference to Exhibit 14 filed with the Company's report on Form 8-K filed on July 22, 2011.

[12] Incorporated by reference to the same exhibit filed with the Company's report on Form 8-K filed on October 25, 2012.

SYNERGY RESOURCES CORPORATION

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder
Synergy Resources Corporation

We have audited the accompanying balance sheets of Synergy Resources Corporation ("the Company") as of August 31, 2012 and 2011, and the related statements of operations, changes in shareholders' equity, and cash flows for each of the years in the three year period ended August 31, 2012. We have also audited the Company's internal control over financial reporting as of August 31, 2012, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, 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 report. Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting 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 audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Synergy Resources Corporation as of August 31, 2012 and 2011, and the results of its operations and its cash flows for each of the years in the three year period ended August 31, 2012 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, Synergy Resources Corporation maintained, in all material respects, effective internal control over financial reporting as of August 31, 2012, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

/s/ Ehrhardt Keefe Steiner & Hottman PC

Denver, Colorado
November 13, 2012

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SYNERGY RESOURCES CORPORATION
BALANCE SHEETS
As of August 31, 2012 and 2011

	2012	2011
ASSETS		
Current assets:		
Cash and cash equivalents	$ 19,284,382	$ 9,490,506
Accounts receivable:		
Oil and gas sales	3,605,593	2,185,051
Joint interest billing	3,267,967	2,406,473
Inventory	177,985	459,592
Other current assets	131,179	89,336
Total current assets	26,467,106	14,630,958
Property and equipment:		
Evaluated oil and gas properties, net	59,936,400	33,858,200
Unevaluated oil and gas properties	32,483,610	14,756,657
Other property and equipment, net	282,561	283,207
Property and equipment, net	92,702,571	48,898,064
Deferred tax asset, net	332,000	—
Other assets	1,229,611	168,863
Total assets	$ 120,731,288	$ 63,697,885
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 15,592,333	$ 8,746,413
Notes payable, related party	—	5,200,000
Total current liabilities	15,592,333	13,946,413
Revolving credit facility	3,000,000	—
Asset retirement obligations	1,026,796	643,459
Total liabilities	19,619,129	14,589,872
Commitments and contingencies (See Note 12)		
Shareholders' equity:		
Preferred stock - $0.01 par value, 10,000,000 shares authorized: no shares issued and outstanding	—	—
Common stock - $0.001 par value, 100,000,000 shares authorized: 51,409,340 and 36,098,212 shares issued and outstanding, respectively	51,409	36,098
Additional paid-in capital	123,876,389	84,011,496
Accumulated deficit	(22,815,639)	(34,939,581)
Total shareholders' equity	101,112,159	49,108,013
Total liabilities and shareholders' equity	$ 120,731,288	$ 63,697,885

The accompanying notes are an integral part of these financial statements

SYNERGY RESOURCES CORPORATION
STATEMENTS OF OPERATIONS
for the years ended August 31, 2012, 2011 and 2010

	2012	*2011*	*2010*
Revenues:			
Oil and gas revenues	$ 24,969,213	$ 10,001,668	$ 2,158,444
Total revenues	24,969,213	10,001,668	2,158,444
Expenses:			
Lease operating expenses	3,648,465	1,439,818	323,520
Depletion, depreciation and amortization	6,009,510	2,838,307	701,400
General and administrative	3,556,747	2,903,303	1,915,049
Total expenses	13,214,722	7,181,428	2,939,969
Operating income (loss)	11,754,491	2,820,240	(781,525)
Other income (expense):			
Change in fair value of derivative conversion liability	—	(10,229,229)	(7,678,457)
Interest expense, net	—	(4,246,945)	(2,338,849)
Interest income	37,451	55,776	4,659
Total other income (expense)	37,451	(14,420,398)	(10,012,647)
Income (loss) before income taxes	11,791,942	(11,600,158)	(10,794,172)
Income tax benefit	332,000	—	—
Net income (loss)	$ 12,123,942	$ (11,600,158)	$ (10,794,172)
Net income (loss) per common share:			
Basic	$ 0.26	$ (0.45)	$ (0.88)
Diluted	$ 0.25	$ (0.45)	$ (0.88)
Weighted average shares outstanding:			
Basic	46,587,558	26,009,283	12,213,999
Diluted	48,359,905	26,009,283	12,213,999

The accompanying notes are an integral part of these financial statements

SYNERGY RESOURCES CORPORATION
STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY
for the years ended August 31, 2012, 2011 and 2010

	Number of Common Shares	Common Stock	Additional Paid - In Capital	Accumulated Earnings (Deficit)	Total Shareholders' Equity (Deficit)
Balance, August 31, 2009	11,998,000	$ 11,998	$ 15,521,697	$ (12,545,251)	$ 2,988,444
Shares issued pursuant to conversion of debt and accrued interest at $1.60 per share, net of $165,212 unamortized debt discount	1,309,027	1,309	1,927,917	—	1,929,226
Reclassification of derivative conversion liability to equity pursuant to early conversion of debt	—	—	1,809,149	—	1,809,149
Shares issued in exchange for mineral leases and services	203,954	204	561,016	—	561,220
Series C warrants issued in connection with sale of convertible debt at $100,000 per Unit pursuant to the November 27, 2009 offering memorandum	—	—	1,760,048	—	1,760,048
Series D warrants issued in connection with sale of convertible debt at $100,000 per Unit pursuant to the November 27, 2009 offering memorandum	—	—	692,478	—	692,478
Share based compensation	—	—	36,658	—	36,658
Net (loss)	—	—	—	(10,794,172)	(10,794,172)
Balance, August 31, 2010	13,510,981	$ 13,511	$ 22,308,963	$ (23,339,423)	$ (1,016,949)
Shares issued pursuant to conversion of debt and accrued interest at $1.60 per share, net of $1,052,917 unamortized debt discount	9,979,376	9,979	14,904,100	—	14,914,079
Reclassification of derivative conversion liability to equity pursuant to early conversion of debt	—	—	19,554,346	—	19,554,346
Shares issued in exchange for mineral leases and services	1,999,838	2,000	5,668,307	—	5,670,307
Shares issued in exchange for oil and gas assets, related party	1,381,818	1,382	4,696,799	—	4,698,181
Shares issued for cash at $2.00 per share pursuant to the November 30, 2010 offering memorandum, net of offering costs of $1,309,279	9,000,000	9,000	16,681,721	—	16,690,721
Shares issued pursuant to conversion of Series D warrants ona cashless basis	226,199	226	(226)	—	—
Share based compensation	—	—	197,486	—	197,486
Net (loss)	—	—	—	(11,600,158)	(11,600,158)
Balance, August 31, 2011	36,098,212	$ 36,098	$ 84,011,496	$ (34,939,581)	$ 49,108,013
Shares issued in exchange for mineral leases and services	669,765	670	1,998,190	—	1,998,860
Shares issued for cash at $2.75 per share pursuant to the October 7, 2011 offering memorandum, net of offering costs of $2,028,215	14,636,363	14,636	37,407,147	—	37,421,783
Share based compensation	5,000	5	459,556	—	459,561
Net income	—	—	—	12,123,942	12,123,942
Balance, August 31, 2012	51,409,340	$ 51,409	$ 123,876,389	$ (22,815,639)	$ 101,112,159

The accompanying notes are an integral part of these financial statements

SYNERGY RESOURCES CORPORATION
STATEMENTS OF CASH FLOWS
for the years ended August 31, 2012, 2011 and 2010

	2012	2011	2010
Cash flows from operating activities:			
Net income (loss)	$ 12,123,942	$ (11,600,158)	$ (10,794,172)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and amortization	6,009,510	2,838,307	701,400
Amortization of debt issuance cost	—	1,587,799	453,656
Accretion of debt discount	—	2,664,138	1,333,590
Provision for deferred taxes	(332,000)	—	—
Stock—based compensation	473,040	627,486	581,233
Change in fair value of derivative liability	—	10,229,229	7,678,457
Changes in operating assets and liabilities:			
Accounts receivable	(2,282,036)	(1,415,204)	(3,091,677)
Inventory	281,607	(71,728)	744,821
Accounts payable	(154,493)	1,549,400	(518,942)
Accrued expenses	6,235,123	1,666,928	460,780
Other	(1,102,591)	(159,889)	7,795
Total adjustments	9,128,160	19,516,466	8,351,113
Net cash provided by (used in) operating activities	21,252,102	7,916,308	(2,443,059)
Cash flows from investing activities:			
Acquisition of property and equipment	(46,751,260)	(30,247,327)	(9,152,175)
Net proceeds from sales of oil and gas properties	71,251	8,382,167	—
Net cash used in investing activities	(46,680,009)	(21,865,160)	(9,152,175)
Cash flows from financing activities:			
Cash proceeds from sale of stock	40,249,998	18,000,000	—
Offering costs	(2,828,215)	(1,309,279)	—
Net proceeds from (repayments of) revolving credit facility	3,000,000	—	(1,161,811)
Cash proceeds from convertible promissory notes	—	—	18,000,000
Debt issuance costs	—	—	(1,348,977)
Principal repayment of related party notes payable	(5,200,000)	—	—
Net cash provided by financing activities	35,221,783	16,690,721	15,489,212
Net increase in cash and equivalents	9,793,876	2,741,869	3,893,978
Cash and equivalents at beginning of period	9,490,506	6,748,637	2,854,659
Cash and equivalents at end of period	$ 19,284,382	$ 9,490,506	$ 6,748,637

Supplemental Cash Flow Information (See Note 13)

The accompanying notes are an integral part of these financial statements

1. Organization and Summary of Significant Accounting Policies

Organization: Synergy Resources Corporation ("the Company") is engaged in oil and gas acquisition, exploration, development and production activities, primarily in the Denver-Julesburg Basin ("D-J Basin") of Colorado.

Basis of Presentation: The Company has adopted August 31st as the end of its fiscal year. The Company does not utilize any special purpose entities.

At the directive of the Securities and Exchange Commission to use "plain English" in public filings, the Company will use such terms as "we," "our," "us" or "the Company" in place of Synergy Resources Corporation. When such terms are used in this manner throughout this document, they are in reference only to the corporation, Synergy Resources Corporation, and are not used in reference to the Board of Directors, corporate officers, management, or any individual employee or group of employees.

The Company prepares its financial statements in accordance with accounting principles generally accepted in the United States of America ("US GAAP").

Cash and Cash Equivalents: The Company considers cash in banks, deposits in transit, and highly liquid debt instruments purchased with original maturities of three months or less to be cash and cash equivalents.

Oil and Gas Reserves: Oil and gas reserves represent theoretical, estimated quantities of crude oil and natural gas which geological and engineering data estimate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. There are numerous uncertainties inherent in estimating oil and gas reserves and their values, including many factors beyond the Company's control. Accordingly, reserve estimates are different from the future quantities of oil and gas that are ultimately recovered and the corresponding lifting costs associated with the recovery of these reserves.

The determination of depletion and amortization expenses, as well as the ceiling test calculation related to the recorded value of the Company's oil and natural gas properties, is highly dependent on estimates of proved oil and natural gas reserves.

Oil and Gas Properties: The Company uses the full cost method of accounting for costs related to its oil and gas properties. Accordingly, all costs associated with acquisition, exploration, and development of oil and gas reserves (including the costs of unsuccessful efforts) are capitalized into a single full cost pool. These costs include land acquisition costs, geological and geophysical expense, carrying charges on non-producing properties, costs of drilling and overhead charges directly related to acquisition and exploration activities. Under the full cost method, no gain or loss is recognized upon the sale or abandonment of oil and gas properties unless non-recognition of such gain or loss would significantly alter the relationship between capitalized costs and proved oil and gas reserves.

Capitalized costs of oil and gas properties are depleted using the unit-of-production method based upon estimates of proved reserves. For depletion purposes, the volume of petroleum reserves and production is converted into a common unit of measure at the energy equivalent conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil. Investments in unevaluated properties and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. If the results of an assessment indicate that the properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized.

Under the full cost method of accounting, capitalized costs are subject to an impairment test known as a ceiling test. For each cost center, capitalized costs, less accumulated amortization and related deferred income taxes, cannot exceed an amount (the cost center ceiling) equal to the sum of i) the present value of estimated future net cash flows from proved oil and gas reserves, computed by applying current prices, as defined, to estimated future production, less estimated future expenditures to be incurred in developing and producing the proved reserves using a discount factor of 10 percent and assuming continuation of existing economic conditions; plus ii) the cost of properties not being amortized; plus iii) the lower of cost or estimated fair value of unproven properties included in the costs being amortized; less iv) income tax effects related to differences between the future net revenues and value and the tax bases of the related assets. If amounts recorded as capitalized costs, less accumulated amortization and related deferred income taxes, exceed the cost center ceiling, the excess is considered an impairment that is immediately charged to expense. Once an impairment expense is recorded, it cannot be reinstated in future periods, even if subsequent events increase the cost center ceiling. For purposes of the ceiling test calculation, current prices are defined as the unweighted arithmetic average of the first day of the month price for each month within the 12 month period prior to the end of the reporting period. Prices are adjusted for basis or location differentials. Unless sales contracts specify otherwise, prices are held constant for the productive life of each well. Similarly, current costs are assumed to remain constant over the entire calculation period.

Capitalized Overhead: A portion of the Company's overhead expenses are directly attributable to acquisition and development activities. Under the full cost method of accounting, these expenses in the amounts showing in the table below were capitalized in the full cost pool.

	2012	*2011*	*2010*
Capitalized overhead	$ 345,343	$ 206,233	$ 95,475

Capitalized Interest: The Company capitalizes interest on expenditures made in connection with acquisition of mineral interests and development projects that are not subject to current amortization. Interest is capitalized during the period that activities are in progress to bring the projects to their intended use.

	2012	*2011*	*2010*
Capitalized interest	$ 208,343	$ 710,137	$ 269,761

Accrued Well Costs: The cost of wells in progress are recorded as incurred, generally based upon invoiced amounts or joint interest billings ("JIB"). For those instances in which an invoice or JIB is not received on a timely basis, estimated costs are accrued to oil and gas properties, generally based on the Authorization for Expenditure ("AFE"). Such drilling and completion expenditures are then included in the accounts payable balance.

The balance also includes payables related to drilling and completion activities on operated wells in progress, which, in some cases, contain estimates of costs using Management's best estimates derived from budgets and historical experience. Where costs are accrued for wells in which minority interest owners exist, respective joint interest receivables are also included on the balance sheet.

Other Property and Equipment: Support equipment (including such items as vehicles, well servicing equipment, and office furniture and equipment) is stated at the lower of cost or market. Depreciation of support equipment is computed using primarily the straight-line method over periods ranging from five to seven years.

Inventory: Inventories consist primarily of tubular goods and well equipment to be used in future drilling operations or repair operations and are carried at the lower of cost or market.

Asset Retirement Obligations: The Company's activities are subject to various laws and regulations, including legal and contractual obligations to reclaim, remediate, or otherwise restore properties at the time the asset is permanently removed from service. Calculation of an asset retirement obligation ("ARO") requires estimates about several future events, including the life of the asset, the costs to remove the asset from service, and inflation factors. The ARO is initially estimated based upon discounted cash flows over the life of the asset and is accreted to full value over time using the Company's credit adjusted risk free interest rate. Estimates are periodically reviewed and adjusted to reflect changes.

The present value of a liability for the ARO is initially recorded when it is incurred if a reasonable estimate of fair value can be made. This is typically when a well is completed or an asset is placed in service. When the ARO is initially recorded, the Company capitalizes the cost (asset retirement cost or "ARC") by increasing the carrying value of the related asset. ARCs related to wells are capitalized to the full cost pool and subject to depletion. Over time, the liability increases for the change in its present value (accretion of ARO), while the net capitalized cost decreases over the useful life of the asset, as depletion expense is recognized. In addition, ARCs are included in the ceiling test calculation for valuing the full cost pool.

Derivative Conversion Liability: The Company accounted for the embedded conversion features in its convertible promissory notes, issued during fiscal year 2010, in accordance with the guidance for derivative instruments, which requires a periodic valuation of their fair value and a corresponding recognition of liabilities associated with such derivatives. The recognition of derivative conversion liabilities related to the issuance of convertible debt was applied first to the proceeds of such issuance as a debt discount at the date of the issuance. All subsequent increases or decreases in the fair value of derivative conversion liabilities were recognized as a charge or credit to other income (expense) in results of operations. In connection with the conversion of convertible promissory notes into shares of the Company's common stock, derivative conversion liabilities were reclassified to additional paid-in-capital. The amounts recognized in the financial statements follow.

	2012	*2011*	*2010*
Non-cash expense recognized related to the change in the fair value of derivative conversion liabilities	$ —	$ 10,229,229	$ 7,678,457
Derivative conversion liabilities recognized in additional paid-in-capital	$ —	$ 19,554,346	$ 1,809,149

Debt Issuance Costs: Debt issuance costs incurred in connection with executing convertible promissory notes between December 29, 2009, and March 12, 2011 were classified as a long-term asset. However, as a result of the conversion of all outstanding convertible promissory notes into shares of the Company's common stock, all debt issuance costs were recognized as a component of interest expense through August 31, 2011.

Oil and Gas Sales: The Company derives revenue primarily from the sale of produced crude oil and natural gas produced. Revenues from production from wells in which the Company shares an economic interest with other owners are recognized on the basis of the Company's pro-rata interest. Revenues are reported on a gross basis for the amounts received before taking into account production taxes and lease operating costs, which are reported as separate expenses. Revenue is recorded and receivables are accrued using the sales method, which occurs in the month production is delivered to the purchaser, at which time ownership of the oil is transferred to the purchaser. Payment is generally received between thirty and ninety days after the date of production. Provided that reasonable estimates can be made, revenue and receivables are accrued to recognize delivery of product to the purchaser. Differences between estimates and actual volumes and prices, if any, are adjusted upon final settlement.

Major Customers and Operating Region: The Company operates exclusively within the United States of America. Except for cash and equivalent investments, all of the Company's assets are employed in and all of its revenues are derived from the oil and gas industry.

The Company's oil and gas production is purchased by a few customers. The table below presents the percentages of oil and gas revenue that were purchased by major customers.

	2012	*2011*	*2010*
Company A	68%	75%	57%
Company B	11%	21%	30%
Company C	*	*	13%

* less than 10%

The Company sells production to a small number of customers, as is customary in the industry. Yet, based on the current demand for oil and natural gas, the availability of other buyers, and the Company having the option to sell to other buyers if conditions so warrant, the Company believes that its oil and gas production can be sold in the market in the event that it is not sold to the Company's existing customers. However, in some circumstances, a change in customers may entail significant transition costs and/or shutting in or curtailing production for weeks or even months during the transition to a new customer.

Accounts receivable consist primarily of trade receivables from oil and gas sales and amounts due from other working interest owners whom have been billed for their proportionate share of well costs. The Company typically has the right to withhold future revenue disbursements to recover outstanding joint interest billings on outstanding receivables from joint interest owners.

Customers with balances greater than 10% of total receivable balances as of each of the fiscal year ends presented, are shown in the following table:

	2012	*2011*	*2010*
Company A	35%	31%	27%
Company B	30%	31%	*
Company C	*	13%	*

* less than 10%

Lease operating expenses: Costs incurred to operate and maintain wells and related equipment and facilities are expensed as incurred. Lease operating expenses (also referred to as production or lifting costs) include the costs of labor to operate the wells and related equipment and facilities, repairs and maintenance, materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities, property taxes and insurance applicable to proved properties and wells and related equipment and facilities, and severance taxes.

Stock-Based Compensation: The Company recognizes all equity-based compensation as stock-based compensation expense based on the fair value of the compensation measured at the grant date, calculated using the Black-Scholes-Merton option pricing model. The expense is recognized over the vesting period of the grant. See Note 9 below for additional information.

Income Tax: Income taxes are computed using the asset and liability method. Accordingly, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities, their respective tax bases as well as the effect of net operating losses, tax credits and tax credit carry-forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the year in which the differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in income tax rates is recognized in the results of operations in the period that includes the enactment date.

No significant uncertain tax positions were identified as of any date on or before August 31, 2012. The Company's policy is to recognize interest and penalties related to uncertain tax benefits in income tax expense. As of August 31, 2012, the Company has not recognized any interest or penalties related to uncertain tax benefits. For further information, see Note 10 below.

Financial Instruments and Hedging Activities: The Company considers cash in banks, deposits in transit, and highly liquid debt instruments purchased with original maturities of three months or less to be cash and cash equivalents. A substantial portion of the Company's financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, accrued liabilities, and obligations under the revolving line of credit facility, all of which are considered to be representative of their fair value, due to the short-term and highly liquid nature of these instruments.

Financial instruments and nonfinancial assets and liabilities, whether measured on a recurring or non-recurring basis, are recorded at fair value. A fair value hierarchy, established by the Financial Accounting Standards Board, prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements).

As discussed in Note 5, the Company incurred asset retirement obligations during the fiscal years presented, the value of which was determined using unobservable pricing inputs (or Level 3 inputs). The Company uses the income valuation technique to estimate the fair value of the obligation using several assumptions and judgments about the ultimate settlement amounts, inflation factors, credit adjusted discount rates, and timing of settlement.

The Company did not have any hedging activities in any of the fiscal years presented. Hedging strategies, or absence of hedging, may vary or change due to change of circumstances, unforeseen opportunities, inability to fund margin requirements, lending institution requirements and other events.

Earnings Per Share Amounts: Basic earnings per share includes no dilution and is computed by dividing net income or loss by the weighted-average number of shares outstanding during the period. Diluted earnings per share reflect the potential dilution of securities that could share in the earnings of the Company. The number of potential shares outstanding relating to stock options and warrants is computed using the treasury stock method. Potentially dilutive securities outstanding are not included in the calculation when such securities would have an anti-dilutive effect on earnings per share.

The following table sets forth the share calculation of diluted earnings per share.

	2012	*2011*	*2010*
Weighted-average shares outstanding - basic	46,587,558	26,009,283	12,213,999
Potentially dilutive common shares from:			
Stock options	1,380,861	—	—
Warrants	391,486	—	—
Weighted-average shares outstanding - diluted	48,359,905	26,009,283	12,213,999

The following potentially dilutive securities outstanding for the fiscal years presented were not included in the respective earnings per share calculation above, as such securities had an anti-dilutive effect on earnings per share:

	2012	*2011*	*2010*
Potentially dilutive common shares from:			
Convertible promissory notes and related accrued interest	—	—	10,077,568
Stock options	2,495,000	4,645,000	4,220,000
Warrants	14,098,000	14,931,067	15,286,466
Total	16,593,000	19,576,067	29,584,034

Use of Estimates: The preparation of financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amount of assets and liabilities, including oil and gas reserves, 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. Management routinely makes judgments and estimates about the effects of matters that are inherently uncertain. Management bases its estimates and judgments on historical experience and on various other factors that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Estimates and assumptions are revised periodically and the effects of revisions are reflected in the financial statements in the period it is determined to be necessary. Actual results could differ from these estimates.

Reclassifications: Certain amounts previously presented for prior periods have been reclassified to conform to the current presentation. The reclassifications had no effect on net loss, working capital or equity previously reported.

Recent Accounting Pronouncements: The Company evaluates the pronouncements of various authoritative accounting organizations to determine the impact of new pronouncements on US GAAP and the impact on the Company.

In December 2011, the FASB issued ASU 2011-11, Balance Sheet (Topic 210): *Disclosures about Offsetting Assets and Liabilities.* This ASU requires the Company to disclose both net and gross information about assets and liabilities that have been offset, if any, and the related arrangements. The disclosures under this new guidance are required to be provided retrospectively for all comparative periods presented. The Company is required to implement this guidance effective for the first quarter of fiscal 2014 and does not expect the adoption of ASU 2011-11 to have a material impact on its financial statements.

Various other accounting standards updates were recently issued, most of which represented technical corrections to the accounting literature or were applicable to specific industries, and are not expected to a have a material impact on the Company's financial position, results of operations or cash flows.

2. Property and Equipment

Capitalized costs of property and equipment consisted of the following:

	2012	*2011*
Oil and gas properties, full cost method:		
Unevaluated costs, not subject to amortization:		
Lease acquisition and other costs	$ 27,070,095	$ 9,942,908
Wells in progress	5,413,515	4,813,749
Subtotal, unevaluated costs	32,483,610	14,756,657
Evaluated costs:		
Producing and non-producing	69,666,725	37,750,737
Total capitalized costs	102,150,335	52,507,394
Less, accumulated depletion	(9,730,325)	(3,892,537)
Oil and gas properties, net	92,420,010	48,614,857
Other property and equipment:		
Vehicles	163,904	163,904
Leasehold improvements	71,651	35,490
Office equipment	156,893	105,089
Land	43,750	43,750
Less, accumulated depreciation	(153,637)	(65,026)
Other property and equipment, net	282,561	283,207
Total property and equipment, net	$ 92,702,571	$ 48,898,064

Periodically, the Company reviews its unevaluated properties to determine if the carrying value of such assets exceeds estimated fair value. The reviews as of each of the fiscal year ends presented, indicated that estimated fair values of such assets exceeded carrying values, thus revealing no impairment. The full cost ceiling test, explained in Note 1, and, as performed as of each of the fiscal year ends presented, similarly revealed no impairment of oil and gas assets.

Costs Incurred: Costs incurred in oil and gas property acquisition, exploration and development activities for the fiscal years presented were:

	2012	*2011*	*2010*
Acquisition of Property:			
Unproved	$ 9,144,453	$ 9,198,417	$ 1,625,696
Proved	459,250	21,251,032	—
Exploration costs	—	—	—
Development costs	39,739,012	14,996,899	10,107,402
Asset retirement obligation	300,226	351,083	253,114
Total Costs Incurred	$ 49,642,941	$ 45,797,431	$ 11,986,212

Capitalized Costs Excluded from Amortization: The following table summarizes costs related to unevaluated properties that have been excluded from amounts subject to depletion, depreciation, and amortization at August 31, 2012. There were no individually significant properties or significant development projects included in the Company's unevaluated property balance. The Company regularly evaluates these costs to determine whether impairment has occurred. The majority of these costs are expected to be evaluated and included in the amortization base within three years.

	Period Incurred				Total as of
	2012	*2011*	*2010*	*2009*	*August 31, 2012*
Unproved leasehold acquisition costs	$ 9,636,019	$ 16,585,380	$ 428,218	$ 420,478	$ 27,070,095
Unevaluated development costs	5,358,970	54,545	—	—	5,413,515
Total unevaluated costs	$ 14,994,989	$ 16,639,925	$ 428,218	$ 420,478	$ 32,483,610

3. Depletion, depreciation and amortization ("DDA")

Depletion, depreciation and amortization consisted of the following:

	2012	*2011*	*2010*
Depletion	$ 5,837,788	$ 2,743,441	$ 692,274
Depreciation	88,611	57,138	7,592
Amortization	83,111	37,728	1,534
Total DDA expense	$ 6,009,510	$ 2,838,307	$ 701,400
Depletion expense per BOE	$ 13.88	$ 16.62	$ 15.52

Capitalized costs of evaluated oil and gas properties are depleted quarterly using the units-of-production method based on a depletion rate, which is calculated by comparing production volumes for the quarter to estimated total reserves at the beginning of the quarter.

4. Accounts Payable and Accrued Expenses

Accounts payable and accrued expenses consisted of the following:

		2012		2011
Trade accounts payable	$	1,498,700	$	1,653,193
Well costs payable		5,732,658		4,967,368
Revenue payable		4,160,554		—
Production taxes payable		3,805,377		1,526,328
Other accrued expenses		395,044		599,524
Total accounts payable and accrued expenses	$	15,592,333	$	8,746,413

5. Asset Retirement Obligations

During the fiscal years presented, the Company brought a number of oil and gas wells into productive status and will have asset retirement obligations once the wells are permanently removed from service. Additionally, the Company acquired a number of oil and gas properties for which the Company assumed the future responsibility to plug and abandon the producing wells, therefore, recorded the associated ARO for these properties. The primary obligations involve the removal and disposal of surface equipment, plugging and abandoning the wells, and site restoration. For the purpose of determining the fair value of ARO incurred during the fiscal years presented, the Company used the following assumptions:

	2012	2011
Inflation rate	3.9 - 4.0%	4.0%
Estimated asset life	24.0 - 27.6 years	24.0 years
Credit adjusted risk free interest rate	11.2 - 11.7%	11.6%

The following table summarizes the changes in asset retirement obligations associated with the Company's oil and gas properties:

		2012		2011
Beginning asset retirement obligation	$	643,459	$	254,648
Liabilities incurred		300,226		351,083
Liabilities settled		—		—
Accretion expense		83,111		37,728
Revisions in previous estimates		—		—
Ending asset retirement obligation	$	1,026,796	$	643,459

6. Revolving Bank Credit Facility

The Company has entered into a revolving line of credit facility ("LOC") with Community Banks of Colorado (successor in interest to Bank of Choice). As of August 31, 2012, interest under the LOC is payable monthly and accrues at the bank's prime rate, subject to a minimum rate. The arrangement contains covenants that, among other things, restrict the payment of dividends and require compliance with certain customary financial ratios, for which the Company was fully in compliance as of each of the fiscal year ends presented. Certain of the Company's assets, including substantially all developed properties, have been designated as collateral under the arrangement. The borrowing commitment is subject to adjustment based upon a borrowing base calculation that includes the value of oil and gas reserves. The borrowing commitment is not currently reduced by the borrowing base calculation. The credit facility expires on November 30, 2014.

Terms of the LOC as of the respective fiscal year end are as follows:

	2012	2011
Total borrowing commitment	$ 20,000,000	$ 7,000,000
Available borrowing capacity	$ 17,000,000	$ 6,975,000
Minimum annual interest rate	3.25%	5.50%
Period end prime rate	3.25%	5.25%

See Note 16 below regarding the amendment to increase the line's borrowing capacity subsequent to August 31, 2012.

7. Interest Expense

The components of interest expense are:

	2012	2011	2010
Revolving bank credit facility at a variable rate	$ 108,004	$ 41,559	$ 30,388
Convertible promissory notes at 8%	—	589,539	790,976
Related party note payable at 5.25%	68,063	74,047	—
Accretion of debt discount	—	2,664,138	1,333,590
Amortization of debt issuance costs	32,276	1,587,799	453,656
Less, interest capitalized	(208,343)	(710,137)	(269,761)
Interest expense, net	$ —	$ 4,246,945	$ 2,338,849

8. Shareholders' Equity

The Company's classes of stock are summarized as follows:

	2012	2011	2010
Preferred stock, shares authorized	10,000,000	10,000,000	10,000,000
Preferred stock, par value	$ 0.01	$ 0.01	$ 0.01
Preferred stock, shares issued and outstanding	—	—	—
Common stock, shares authorized	100,000,000	100,000,000	100,000,000
Common stock, par value	$ 0.001	$ 0.001	$ 0.001
Common stock, shares issued and outstanding	51,409,340	36,098,212	13,510,981

Preferred Stock may be issued in series with such rights and preferences as may be determined by the Board of Directors. Since inception, the Company has not issued any preferred shares.

The following shares of common stock were issued during the fiscal years presented:

Sale of common stock

During fiscal year 2012, the Company completed the sale of common stock in a public offering. The underwriters were Northland Capital Markets, C.K. Cooper & Company, and GVC Capital, LLC.

In fiscal year 2011, the Company completed the sale of common stock to private investors.

A summary of each transaction is shown below, including net proceeds to the Company, which are provided after deductions for the underwriting discounts, commissions and expenses of the offering.

	2012	2011	2010
Number of common shares sold	14,636,363	9,000,000	—
Offering price per common share	$ 2.75	$ 2.00	$ —
Net proceeds	$ 37,421,783	$ 16,690,721	$ —

Common stock issued to settle promissory notes

During the fiscal year ended August 31, 2010, we issued convertible promissory notes with a face value of $18,000,000, which could be converted into shares of common stock at a rate of $1.60 per share. All of the noteholders elected to convert, the details of which follow.

	2012	2011	2010
Proceeds from the issuance of promissory notes	$ —	$ —	$ 18,000,000
Subsequent settlement of amounts owing:			
Value of promissory notes settled in common shares	—	15,908,000	2,092,000
Value of interest accrued on promissory notes settled in common shares	—	58,996	2,438
Number of common shares issued as settlement of promissory notes and related interest	—	9,940,973	1,309,027
Conversion price per common share	N/A	$ 1.60	$ 1.60

Common stock issued for acquisition of mineral interests and services

During the fiscal years presented, the Company issued common shares in exchange for mineral property interests and to individuals as compensation for services provided to the Company. The value of each transaction was determined using the market price of the Company's common stock on the date of each transaction.

	2012	2011	2010
Number of common shares issued for property and services	669,765	1,864,838	203,954
Average price per common share	$ 3.12	$ 3.04	$ 2.75
Aggregate value of shares issued	$ 2,090,163	$ 5,670,307	$ 561,220

Common stock warrants

The following table summarizes information about the Company's issued and outstanding common stock warrants as of August 31, 2012:

Exercise Price	Description		Number of Shares	Remaining Contractual Life (in years)	Exercise Price times Number of Shares
$1.60	Series D	1	769,601	2.30	$ 1,231,362
$1.80	Sales Agent Warrants	2	63,466	0.30	114,239
$2.69	Investor Relation Warrants	3	100,000	3.45	269,000
$6.00	Series A	2,4	4,098,000	0.30	24,588,000
$6.00	Series C	1	9,000,000	2.30	54,000,000
$10.00	Series B	2	1,000,000	0.30	10,000,000
			15,031,067	1.62	$ 90,202,601

[1] Between December 2009 and March 2010, the Company sold 180 Units at a price of $100,000 per Unit to private investors. Each Unit consisted of one $100,000 note and 50,000 Series C warrants. The notes were convertible into shares of the Company's common stock at a conversion price of $1.60 per share, at the option of the holder. Each Series C warrant entitles the holder to purchase one share of the Company's common stock at a price of $6.00 per share at any time prior to December 31, 2014. As of prior fiscal year end, August 31, 2011, all notes had been converted into 11,250,000 shares of Company common stock.

The Company paid Bathgate Capital Partners (now named GVC Capital), the placement agent for the Unit offering, a commission of 8% of the amount Bathgate Capital raised in the Unit offering. The Company also sold to the placement agent, for a nominal price, warrants to purchase 1,125,000 shares of our common stock at a price of $1.60 per share. The placement agent's warrants expire on December 31, 2014. As of August 31, 2012, warrants to purchase 355,399 shares had been exercised by their holders.

[2] Between December 1, 2008 and June 30, 2009, the Company sold 1,000,000 units at a price of $3.00 per unit. Each Unit consisted of two shares of the Company's common stock, one Series A warrant and one Series B warrant. The Series A warrants are identical to the Series A warrants described below. Each Series B warrant entitles the holder to purchase one share of the Company's common stock at a price of $10.00 per share at any time prior to December 31, 2012.

In connection with this unit offering, the Company paid the sales agent for the offering a commission of 10% of the amount the sales agent sold in the offering. The Company also issued warrants to the sales agent. The warrants allow the sales agent to purchase 31,733 Units (which Units were identical to the units sold in the offering) at a price of $3.60 per Unit. The sales agent warrants will expire on the earlier of December 31, 2012, or twenty days following written notification from the Company that our common stock had a closing bid price at or above $7.00 per share for any ten of twenty consecutive trading days.

[3] During the fiscal year ended August 31, 2012, the Company entered into an agreement with a public relations firm, and agreed to issue warrants to the firm in exchange for services provided. For the one year term, warrants to purchase 100,000 shares of stock at $2.69 per share are available to the firm and become exercisable at quarterly intervals upon the Company being satisfied with the firm's services.

[4] Each shareholder of record on the close of business on September 9, 2008, received one Series A warrant for each share which they owned on that date (as adjusted for a reverse split of the Company's common stock which was effective on September 22, 2008). Prior to September 9, 2008, a corporation which the Company acquired on that date sold 1,000,000 Units at a price of $1.00 per Unit and 1,060,000 Units at a price of $1.50 per Unit to private investors. Each Unit consisted of one share of the corporation's common stock and one Series A warrant. In connection with the acquisition of the corporation, these Series A warrants were exchanged for 2,060,000 of the Company's Series A warrants. Each Series A warrant entitles the holder to purchase one share of the Company's common stock at a price of $6.00 per share at any time prior to December 31, 2012.

The following table summarizes activity for common stock warrants for the fiscal years presented:

	Number of Warrants	Weighted Average Exercise Price
Outstanding, August 31, 2009	5,161,466	$6.72
Granted	10,125,000	$5.51
Exercised	—	$0.00
Outstanding, August 31, 2010	15,286,466	$5.92
Granted	—	$0.00
Exercised	355,399	$1.60
Outstanding, August 31, 2011	14,931,067	$6.02
Granted	100,000	$2.69
Exercised	—	$0.00
Outstanding, August 31, 2012	15,031,067	$6.02

Information concerning stock options is contained in Note 9.

9. Stock-Based Compensation

The Company recorded stock-based compensation expense in the amounts shown in the table below for each of the fiscal years presented. The expense pertains to stock grants to employees, directors and a consultant, as detailed below. All the expenses listed below are included within General and Administrative expenses on the Statements of Operations.

	2012	*2011*	*2010*
Stock-based compensation expense	$ 473,040	$ 627,486	$ 581,233

General Description of Stock Option and Other Stock Award Plans

The Company has three stock award plans: (i) a 2011 non-qualified stock option plan, (ii) a 2011 incentive stock option plan, and (iii) a 2011 stock bonus plan. The plans adopted during 2011 replaced a non-qualified stock option plan and a stock bonus plan originally adopted during 2005 (the "2005 Plans"). No additional options or shares will be issued under the 2005 Plans.

Each plan authorizes the issuance of shares of the Company's common stock to persons that exercise options granted pursuant to the Plan. Employees, directors, officers, consultants and advisors are eligible to receive such awards, provided that bona fide services be rendered by such consultants or advisors and such services must not be in connection with promoting our stock or the sale of securities in a capital-raising transaction. The option exercise price is determined by the Board of Directors, though is generally the closing market price of Company stock on the date of grant.

As of August 31, 2012, there were 2,000,000 shares authorized for issuance under each of the aforementioned plans.

During the respective fiscal years, the Company granted the following employee stock options:

	2012	*2011*	*2010*
Number of options to purchase common shares	275,000	425,000	120,000
Weighted average exercise price	$ 2.96	$ 3.79	$ 2.50
Term	10 years	10 years	10 years
Vesting period	4 - 5 years	4 - 5 years	2 - 5 years
Fair value	$ 519,076	$ 990,250	$ 156,000

The Company records an expense related to stock options by pro-rating the estimated fair value of the option grant over the period of time that the recipient is required to provide services to the Company (the "vesting phase"). For the grant of various stock options that are currently in the vesting phase, the Company recorded stock-based compensation expense as follows:

The assumptions used in valuing stock options granted during each of the fiscal years presented were as follows:

	2012	*2011*	*2010*
Expected term	6.5 years	6.0 - 6.5 years	5.9 years
Expected volatility	56.74 - 69.43%	53.18 - 69.43%	53.18%
Risk free rate	1.01% - 1.42%	1.48% - 2.63%	2.08%
Expected dividend yield	0.00%	0.00%	0.00%
Forfeiture rate	0.00% - 0.69%	0.00%	0.00%

The following table summarizes activity for stock options for the fiscal years presented:

	Number of Shares	Weighted Average Exercise Price
Outstanding, August 31, 2009	4,100,000	$5.50
Granted	120,000	$2.50
Exercised	—	$0.00
Outstanding, August 31, 2010	4,220,000	$5.36
Granted	425,000	$3.79
Exercised	—	$0.00
Outstanding, August 31, 2011	4,645,000	$5.21
Granted	275,000	$2.96
Exercised	—	$0.00
Forfeited	(5,000)	$3.40
Outstanding, August 31, 2012	4,915,000	$5.09

The following table summarizes information about issued and outstanding stock options as of August 31, 2012:

	Outstanding Options	Vested Options
Number of shares	4,915,000	4,270,500
Weighted average remaining contractual life	2.2 years	1.2 years
Weighted average exercise price	$ 5.09	$ 5.35
Aggregate intrinsic value	$ 3,656,000	$ 3,640,400

The estimated unrecognized compensation cost from unvested stock options as of August 31, 2012, which will be recognized ratably over the remaining vesting phase, is as follows:

	Unvested Options at August 31, 2012
Unrecognized compensation expense	$ 1,162,556
Remaining vesting phase	3.4 years

10. Income Taxes

The income tax benefit is comprised of the following:

	2012	2011	2010
Current:			
Federal	$ —	$ —	$ —
State	—	—	—
Total current income tax	—	—	—
Deferred:			
Federal	(4,219,000)	4,266,000	3,670,000
State	(360,000)	354,000	324,000
Total deferred income tax	(4,579,000)	4,620,000	3,994,000
Valuation allowance	4,911,000	(4,620,000)	(3,994,000)
Income tax benefit	$ 332,000	$ —	$ —

A reconciliation of expected federal income taxes on income from continuing operations at statutory rates with the (expense) benefit for income taxes is follows:

	2012	2011	2010
Federal income tax at statutory rate	$ (4,009,000)	$ 3,944,000	$ 3,670,000
State income taxes, net of federal benefit	(360,000)	354,000	324,000
Other	(210,000)	322,000	—
Change in valuation allowance	4,911,000	(4,620,000)	(3,994,000)
Income tax benefit	$ 332,000	$ —	$ —
Effective rate expressed as a percentage	3%	0%	0%

The Company reported a change in valuation allowance of $4,911,000 for the year ended August 31, 2012. In assessing the realizability of deferred tax assets, the Company considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. Management considers all available evidence (both positive and negative) in determining whether a valuation allowance is required. Such evidence includes the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment, and judgment is required in considering the relative weight of negative and positive evidence. The Company continues to monitor facts and circumstances in the reassessment of the likelihood that operating loss carry-forwards, credits and other deferred tax assets will be utilized prior to their expiration. As a result, it may be determined that a deferred tax asset valuation allowance should be established or released. Any increases or decreases in a deferred tax asset valuation allowance would impact net income through offsetting changes in income tax expense. In 2012, the Company determined that the weight of the evidence indicated that it would more likely than not be able to realize its deferred tax asset, and the entire valuation allowance was released.

The tax effects of temporary differences that give rise to significant components of the deferred tax assets and deferred tax liabilities at each of the fiscal year ends presented follow:

		2012		2011
Deferred tax assets:				
Net operating loss carry-forward	$	12,643,000	$	4,176,000
Stock-based compensation		4,070,000		3,913,000
Other		3,000		69,000
Valuation allowance		—		(4,911,000)
Gross deferred tax assets		16,716,000		3,247,000
Deferred tax liabilities:				
Basis of oil and gas properties		(16,384,000)		(3,247,000)
Gross deferred tax liabilities		(16,384,000)		(3,247,000)
Deferred tax assets, net	$	332,000	$	—

The Company has net operating loss ("NOL") carry-forwards for federal and state tax purposes approximating $34,000,000 that may be utilized to offset taxable income of future years. Substantially all of the carry-forwards will expire between 2030 and 2032.

The realization of the deferred tax assets related to the NOL carry-forwards is dependent on the Company's ability to generate sufficient future taxable income within the applicable carryforward periods. As of August 31, 2012, the Company believes it will be able to generate sufficient future taxable income within the carryforward periods, and accordingly believes that it is more likely than not that its net deferred income tax assets will be fully realized.

The ability of the Company to utilize its NOL carry-forwards to reduce future taxable income is subject to various limitations under the Internal Revenue Code of 1986, as amended (the "Code"). The utilization of such carry-forwards may be limited upon the occurrence of certain ownership changes, including the purchase or sale of stock by 5% shareholders and the offering of stock by the Company during any three-year period resulting in an aggregate change of more than 50% in the beneficial ownership of the Company. In the event of an ownership change, Section 382 of the Code imposes an annual limitation on the amount of a Company's taxable income that can be offset by these carry-forwards. The Company completed a study of the impact of the Code Section 382 limitation on future payments and determined that the statutory provisions were unlikely to limit the Company's ability to realize future tax benefits. Accordingly, the Company released the potential Code Section 382 limitation from its tax analysis.

As of August 31, 2011, the Company had a net deferred tax asset of $4,911,000. For reporting periods prior to February 29, 2012, management concluded that it was more likely than not that the Company's net deferred tax asset would not be realized in the foreseeable future and accordingly, a full valuation allowance was provided against the net deferred tax asset. Effective February 29, 2012, management concluded that positive indicators outweighed negative indicators, and that it was appropriate to release the valuation allowance, primarily for the three following reasons. First, all of the net losses for the two prior fiscal years can be attributed to a single discrete item. The discrete item was the fair value accounting treatment of the components of the 8% convertible promissory notes issued in 2010, which created non-cash expenses for accretion of debt discount, amortization of issuance costs, and change in fair value of derivative liability. As all of the convertible notes were converted prior to March 31, 2011, those expenses will not recur, and it is appropriate to exclude them from a consideration of future profitability. Second, the Company had reported three consecutive quarters of net income and six consecutive quarters of operating income. Third, the Company completed a debt financing arrangement and an equity financing arrangement that allowed it to continue with its operating plan. Accordingly, the Company believed that it was appropriate to release the valuation allowance related to the deferred tax asset created by the net operating loss carryover.

As of August 31, 2012, the Company had no unrecognized tax benefits. The Company believes that there are no new items, nor changes in facts or judgments that should impact the Company's tax position. Given the substantial NOL carry-forwards at both the federal and state levels, it is anticipated that any changes resulting from a tax examination would simply adjust the carry-forwards, and would not result in significant interest expense or penalties. Substantially of the Company's tax returns filed since inception are still subject to examination by tax authorities.

11. Related Party Transactions and Commitments

Two of the Company's executive officers control three entities that have entered into agreements to provide various goods, services, facilities, and oil and gas properties to the Company. The entities are Petroleum Management, LLC ("PM"), Petroleum Exploration and Management, LLC ("PEM"), and HS Land & Cattle, LLC ("HSLC").

Acquisition of Oil and Gas Assets from PEM: During the year ended August 31, 2011, the Company acquired oil and gas assets from PEM, as outlined below.

In May 2011, the Company acquired a working interest in operating oil and gas wells and other oil and gas assets, from PEM. The purchase price consisted of a combination of cash, restricted shares and a note payable, as detailed below. In November 2011, the Company utilized proceeds from the LOC (Note 5) to repay the entire principal balance and accrued interest.

	2012	2011	2010
Consideration for certain mineral assets:			
Cash payments for certain mineral assets	$ —	$ 10,000,000	$ —
Restricted shares of common stock	—	1,381,818	—
Value of restricted shares of common stock	—	4,698,181	—
Promissory note	—	5,200,000	—
Subsequent settlement of amounts owing:			
Repayment of promissory note	$ 5,200,000	$ —	$ —
Payment of interest on promissory note	142,110	—	—

In October 2010, the Company acquired with cash certain mineral assets located in the Wattenberg Field of the D-J Basin, from PM and PEM. The assets acquired included working interests in certain operating oil and gas wells, drill sites, and miscellaneous equipment for a purchase price of $1,017,435.

Other Related Party Transactions: In addition to the transactions described above, the Company undertook various activities with PM and PEM that are related to the development and operation of oil and gas properties. The Company occasionally purchased services and certain oil and gas equipment, such as tubular goods and surface equipment, from PM. The Company reimbursed PM for the original cost of such services and equipment. Prior to the asset acquisition transaction that closed on May 24, 2011, PEM was a joint working interest owner of certain wells operated by the Company. PEM was charged for its pro-rata share of costs and expenses incurred on its behalf by the Company, and similarly, PEM was credited for its pro-rata share of revenues collected on its behalf. Effective with the closing of the asset acquisition, the related party transactions of this nature have ceased.

The following table summarizes the transactions with PM and PEM during the fiscal years presented:

	2012	2011	2010
Purchase of equipment from PM	$ —	$ 2,290	$ 1,070,495
Payments to PM for equipment	—	(540,988)	(531,797)
Balance due to PM for equipment	$ —	$ —	$ 538,698
Joint interest costs billed to PEM	$ —	$ 396,469	$ 1,629,895
Amounts collected from PEM	—	(1,264,304)	(762,060)
Balance due to PEM	$ —	$ —	$ 867,835

Facilities and Services Agreements: The Company leases office space and an equipment storage yard in Platteville, Colorado, under a twelve month lease agreement with HSLC. The lease is renewable annually. Under this agreement, the Company incurred the following expenses to HSLC for the fiscal years presented:

	2012	2011	2010
Rent expense	$ 120,000	$ 120,000	$ 20,000

Prior to executing the lease agreement with HSLC, the Company leased office space as well as received certain services under an Administrative Services Agreement with PM, whereby PM provided office support services, including secretarial service, word processing, communication services, office equipment and supplies. Under these agreements, the Company incurred the following expenses to PM for the fiscal years presented:

	2012	2011	2010
Rent expense	$ —	$ —	$ 100,000
Administrative outsourcing expenses	—	—	106,667

During 2010, the Company initiated a program to acquire mineral interests in several Colorado and Nebraska counties that are considered the eastern portion of the D-J Basin. George Seward, a member of the Company's board of directors, agreed to lead that program. The Company agreed to compensate the persons, including Mr. Seward, to assist the Company with the acquisitions at a specific rate per qualifying net mineral acre. The compensation is paid in the form of restricted shares of the Company's common stock, as follows:

	2012	2011	2010
Restricted shares of common stock	188,137	40,000	—
Value of restricted shares of common stock	$ 491,003	$ 163,600	—

12. Other Commitments and Contingencies

Effective September 1, 2012, the Company entered into a drilling contract with Ensign United States Drilling, Inc. to utilize a drilling rig through December 31, 2012. Total payments due to Ensign will depend upon a number of variables, including the number of wells drilled, the target formation, and other technical details. The Company estimates that this commitment will result in the drilling of 25 wells with total drilling costs of approximately $5.3 million.

From time to time, the Company receives notice from other operators of their intent to drill and operate a well in which the Company will own a working interest. The Company has the option to participate in the well and assume the obligation for its pro-rata share of the costs. As of October 31, 2012, the Company had agreed to participate in four new wells, including two horizontal wells, with working interests ranging from 3% to 31% and aggregate costs to its interest of $1.6 million. No costs for the four wells were accrued as of August 31, 2012. In addition, the Company had been notified that it may have an interest in ten potential wells. As of October 31, 2012, the Company had not yet committed to participate in the future wells and had not determined its potential working interest or cost obligation.

13. Supplemental Schedule of Information to the Statements of Cash Flows

The following table supplements the cash flow information presented in the financial statements for the fiscal years presented:

	2012	2011	2010
Supplemental cash flow information:			
Interest paid	$ 74,047	$ 788,211	$ 617,017
Income taxes paid	—	—	—
Non-cash investing and financing activities:			
Accrued well costs	$ 5,732,658	$ 4,967,369	$ 3,446,439
Assets acquired in exchange for common stock	1,985,381	9,938,488	16,645
Assets acquired in exchange for note payable	—	5,200,000	—
Asset retirement costs and obligations	300,226	351,083	253,114
Conversion of promissory notes into common stock	—	15,908,000	2,092,000
Placement agent commission in the form of warrants	—	—	692,478

14. Unaudited Oil and Gas Reserves Information

Oil and Natural Gas Reserve Information: Proved reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions (prices and costs held constant as of the date the estimate is made). Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped 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.

Proved oil and natural gas reserve information as of the fiscal year ends presented, and the related discounted future net cash flows before income taxes are based on estimates prepared by Ryder Scott Company LP. Reserve information for the properties was prepared in accordance with guidelines established by the SEC.

The reserve estimates prepared as of each of the fiscal year ends presented were prepared in accordance with "Modernization of Oil and Gas Reporting" published by the SEC. The recent guidance included updated definitions of proved developed and proved undeveloped oil and gas reserves, oil and gas producing activities and other terms. Proved oil and gas reserves were calculated based on the prices for oil and gas during the 12 month period before the respective reporting date, determined as the unweighted arithmetic average of the first day of the month price for each month within such period, rather than the year-end spot prices, which had been used in prior years. This average price is also used in calculating the aggregate amount and changes in future cash inflows related to the standardized measure of discounted future cash flows. Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years. The recent guidance broadened the types of technologies that may be used to establish reserve estimates.

The following table sets forth information regarding the Company's net ownership interests in estimated quantities of proved developed and undeveloped oil and gas reserve quantities and changes therein for each of the fiscal years presented:

	Oil (Bbl)	Gas (Mcf)
Balance, August 31, 2009	6,430	25,680
Revision of previous estimates	4,318	24,845
Purchase of reserves in place	—	—
Extensions, discoveries, and other additions	687,017	4,571,680
Sale of reserves in place	—	—
Production	(21,080)	(141,154)
Balance, August 31, 2010	676,685	4,481,051
Revision of previous estimates	323,704	611,516
Purchase of reserves in place	967,302	8,466,714
Extensions, discoveries, and other additions	191,931	1,152,708
Sale of reserves in place	—	—
Production	(89,917)	(450,831)
Balance, August 31, 2011	2,069,705	14,261,158
Revision of previous estimates	429,783	3,298,906
Purchase of reserves in place	33,328	706,842
Extensions, discoveries, and other additions	2,788,686	16,288,125
Sale of reserves in place	—	—
Production	(235,691)	(1,109,057)
Balance, August 31, 2012	5,085,811	33,445,974
Proved developed and undeveloped reserves:		
Developed at August 31, 2010	395,453	2,349,027
Undeveloped at August 31, 2010	281,232	2,132,024
Balance, August 31, 2010	676,685	4,481,051
Developed at August 31, 2011	783,821	5,578,067
Undeveloped at August 31, 2011	1,285,884	8,683,091
Balance, August 31, 2011	2,069,705	14,261,158
Developed at August 31, 2012	2,823,604	17,380,806
Undeveloped at August 31, 2012	2,262,207	16,065,168
Balance, August 31, 2012	5,085,811	33,445,974

Standardized Measure of Discounted Future Net Cash Flows: The following analysis is a standardized measure of future net cash flows and changes therein related to estimated proved reserves. Future oil and gas sales have been computed by applying average prices of oil and gas during each of the fiscal years presented. Future production and development costs were computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs. The calculation assumes the continuation of existing economic conditions, including the use of constant prices and costs. Future income tax expenses were calculated by applying year-end statutory tax rates, with consideration of future tax rates already legislated, to future pretax cash flows relating to proved oil and gas reserves, less the tax basis of properties involved and tax credits and loss carry-forwards relating to oil and gas producing activities. All cash flow amounts are discounted at 10% annually to derive the standardized measure of discounted future cash flows. Actual future cash inflows may vary considerably, and the standardized measure does not necessarily represent the fair value of the Company's oil and gas reserves. Actual future net cash flows from oil and gas properties will also be affected by factors such as actual prices the Company receives for oil and gas, the amount and timing of actual production, supply of and demand for oil and gas, and changes in governmental regulations or taxation.

The following table sets forth the Company's future net cash flows relating to proved oil and gas reserves based on the standardized measure prescribed in the ASC:

	2012	*2011*	*2010*
Future cash inflows	$ 537,461,879	$ 235,238,880	$ 64,670,902
Future production costs	(85,612,228)	(41,277,367)	(16,380,316)
Future development costs	(100,820,886)	(40,404,280)	(15,836,965)
Future income tax expense	(109,348,907)	(30,737,928)	(6,926,890)
Future net cash flows	241,679,858	122,819,305	25,526,731
10% annual discount for estimated timing of cash flows	(139,175,063)	(65,268,891)	(12,504,334)
Standardized measure of discounted future net cash flows	$ 102,504,795	$ 57,550,414	$ 13,022,397

There have been significant fluctuations in the posted prices of oil and natural gas during the last three years. Prices actually received from purchasers of the Company's oil and gas are adjusted from posted prices for location differentials, quality differentials, and BTU content. Estimates of the Company's reserves are based on realized prices.

The following table presents the prices used to prepare the reserve estimates, based upon the unweighted arithmetic average of the first day of the month price for each month within the 12 month period prior to the end of the respective reporting period presented:

	Oil (Bbl)	Gas (Mcf)
August 31, 2010 (Average)	$69.20	$4.76
August 31, 2011 (Average)	$84.90	$5.07
August 31, 2012 (Average)	$86.68	$3.76

Changes in the Standardized Measure of Discounted Future Net Cash Flows: The principle sources of change in the standardized measure of discounted future net cash flows are:

	2012	*2011*	*2010*
Standardized measure, beginning of year	$ 57,550,414	$ 13,022,397	$ 232,957
Sale and transfers, net of production costs	(21,320,748)	(8,337,354)	(1,834,924)
Net changes in prices and production costs	(6,023,491)	15,483,714	131,153
Extensions, discoveries, and improved recovery	69,073,077	13,692,899	17,785,154
Changes in estimated future development costs	(42,578,076)	(20,471,127)	—
Development costs incurred during the period	39,739,012	16,251,935	—
Revision of quantity estimates	21,058,069	15,424,097	212,851
Accretion of discount	15,378,973	3,245,362	30,535
Net change in income taxes	(30,831,685)	(12,011,643)	(3,535,329)
Purchase of reserves in place	459,250	21,250,134	—
Standardized measure, end of year	$ 102,504,795	$ 57,550,414	$ 13,022,397

15. Unaudited Quarterly Financial Data

Fiscal Year ended August 31, 2012:

	First Quarter	*Second Quarter*	*Third Quarter*	*Fourth Quarter*
Revenues	$ 4,478,864	$ 6,218,975	$ 7,521,833	$ 6,749,541
Expenses	2,859,712	3,343,680	3,675,390	3,335,940
Operating income	1,619,152	2,875,295	3,846,443	3,413,601
Other income	8,181	2,510	16,320	10,440
Income before income taxes	1,627,333	2,877,805	3,862,763	3,424,041
Income tax provision (benefit)	— [1]	3,241,000 [2]	(1,432,000)	(1,477,000)
Net income	$ 1,627,333	$ 6,118,805	$ 2,430,763	$ 1,947,041
Net income per common share:				
Basic [4]	$ 0.05	$ 0.13	$ 0.05	$ 0.04
Diluted	$ 0.04	$ 0.12	$ 0.05	$ 0.04
Weighted average shares outstanding:				
Basic	36,098,212	47,445,178	51,292,810	51,409,340
Diluted	37,845,212	49,229,042	53,174,792	53,072,619

Fiscal Year ended August 31, 2011:

	First Quarter	*Second Quarter*	*Third Quarter*	*Fourth Quarter*
Revenues	$ 1,451,037	$ 2,053,534	$ 3,106,336	$ 3,390,761
Expenses	1,440,199	1,367,121	2,559,064	1,815,044
Operating income	10,838	686,413	547,272	1,575,717
Other income (expense)	(1,170,842) [3]	(12,424,773) [3]	(838,884) [3]	14,101
Income (loss) before income taxes	(1,160,004)	(11,738,360)	(291,612)	1,589,818
Income tax	— [1]	— [1]	— [1]	— [1]
Net Income (loss)	$ (1,160,004)	$ (11,738,360)	$ (291,612)	$ 1,589,818
Net income (loss) per common share:				
Basic [4]	$ (0.08)	$ (0.55)	$ (0.01)	$ 0.04
Diluted	$ (0.08)	$ (0.55)	$ (0.01)	$ 0.04
Weighted average shares outstanding:				
Basic	13,715,651	21,487,951	32,813,298	35,788,313
Diluted	13,715,651	21,487,951	32,813,298	35,788,313

[1] No income tax was recognized during these periods as any (provision) benefit for tax at the effective rate was offset by a change in the valuation allowance.

[2] For the three months ended February 29, 2012, we released the entire valuation allowance of $4,911,000 and recorded a net deferred tax asset of $3,241,000.

[3] For each of the three quarters ended November 30, 2010, February 28, 2011, and May 31, 2011, other expense included amounts associated with the 8% convertible promissory notes. The amounts included interest expense, accretion of debt discount, amortization of debt issuance costs, and a change in the fair value of the derivative conversion liability. All expenses related to the convertible promissory notes ceased during the fiscal year ended August 31, 2011, as all noteholders converted their holdings into equity on or prior to August 31, 2011.

[4] The sum of the individual quarterly earnings (loss) per share may not agree with the year-to-date earnings (loss) per share as each quarterly computation is based on the income or loss for that quarter and the weighted-average number of shares outstanding during that quarter.

16. Subsequent Events

Amendment to Line of Credit

On October 18, 2012, the Company entered into an amendment to its revolving line of credit agreement with Community Banks of Colorado, successor in interest to Bank of Choice. The amended terms include an increase from $20,000,000 to $30,000,000 in the maximum amount of borrowings available, subject to certain collateral requirements. Other terms of the agreement, including interest on borrowed amounts and the commitment expiration date of November 30, 2014, were not materially changed.

Agreement to Acquire Oil and Gas Properties

On October 23, 2012, the Company entered into an agreement to acquire oil and gas properties consisting of:

- 36 producing oil and gas wells,
- leases covering approximately 3,933 gross (3,196 net) acres, and
- miscellaneous equipment.

If the acquisition is completed, Synergy will have:

- a 100% working interest (77% net revenue interest) in 29 of the producing wells, with a smaller working/net revenue interest in the remaining 7 wells, and
- working interests ranging from 100% to 10.3% (net revenue interests ranging from 80% to 8.24%) in any wells which it elects to drill and complete on the acquired leases.

The producing oil and gas properties are located in the Wattenberg Field of the D-J Basin.

The purchase price for these oil and gas properties, subject to ordinary closing adjustments, is $42,000,000, payable in cash of $30,000,000 and $12,000,000 in restricted shares of the Company's common stock. The closing of the acquisition is subject to the completion of title reviews by the Company and other conditions normal for a transaction of this nature.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(a) of the Exchange Act, the Registrant has caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized on the 13th day of November, 2012.

SYNERGY RESOURCES CORPORATION

/s/ Ed Holloway

Ed Holloway, President and Chief Executive Officer
(Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of l934, this Report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Ed Holloway Ed Holloway	President, Chief Executive Officer and Director	November 13, 2012
/s/ Frank L. Jennings Frank L. Jennings	Chief Financial Officer	November 13, 2012
/s/ William E. Scaff, Jr. William E. Scaff, Jr.	Director	November 13, 2012
/s/ Rick Wilber Rick Wilber	Director	November 13, 2012
/s/ Raymond E. McElhaney Raymond E. McElhaney	Director	November 13, 2012
/s/ Bill M. Conrad Bill M. Conrad	Director	November 13, 2012
/s/ R. W. Noffsinger, III R. W. Noffsinger, III	Director	November 13, 2012
/s/ George Seward George Seward	Director	November 13, 2012

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the registration statements (No. 333-177123) on Form S-3 of Synergy Resources Corporation of our report dated November 13, 2012, with respect to the financial statements as of and for each of the years ended August 31, 2012, 2011 and 2010, which report appears in the August 31, 2012 annual report on Form 10-K of Synergy Resources Corporation.

/s/ Ehrhardt Keefe Steiner & Hottman PC

November 13, 2012
Denver, Colorado

Exhibit 31.1

CERTIFICATIONS

I, Ed Holloway, certify that:

1. I have reviewed this annual report on Form 10-K of Synergy Resources Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15 and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) designed such internal control over financial reporting, or cause such internal control over financial reporting to be designed under our supervision, 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;

c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of the internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have significant role in the registrant's internal control over financial reporting.

November 13, 2012 /s/ Ed Holloway
Ed Holloway, President and Chief Executive Officer
(President and Principal Executive Officer)

Exhibit 31.2

CERTIFICATIONS

I, Frank L. Jennings, certify that:

1. I have reviewed this annual report on Form 10-K of Synergy Resources Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15 and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) designed such internal control over financial reporting, or cause such internal control over financial reporting to be designed under our supervision, 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;

c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of the internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have significant role in the registrant's internal control over financial reporting.

November 13, 2012 /s/ Frank L. Jennings
Frank L. Jennings, Chief Financial Officer
(Principal Financial and Accounting Officer)

Exhibit 32

In connection with the Annual Report of Synergy Resources Corporation (the "Company") on Form 10-K for the period ending August 31, 2012 as filed with the Securities and Exchange Commission (the "Report"), Ed Holloway, the Company's President and Principal Executive and Frank L. Jennings, the Company's Chief Financial Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of their knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of the Company.

November 13, 2012 By: /s/ Ed Holloway
Ed Holloway, President and Chief Executive Officer
(Principal Executive Officer)

November 13, 2012 By: /s/ Frank L. Jennings
Frank L. Jennings, Chief Financial Officer
(Principal Financial and Accounting Officer)

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE REGISTERED ENGINEERING FIRM F-1580
621 SEVENTEENTH STREET SUITE 1550 DENVER, COLORADO 80293 FAX (303) 623-4258 TELEPHONE (303) 623-9147

November 2, 2012

Synergy Resources Corporation
20203 Highway 60
Platteville, Colorado 80651

Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold interests of Synergy Resources Corporation (Synergy) as of August 31, 2012. The subject properties are located in the state of Colorado. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on November 2, 2012 and presented herein, was prepared for public disclosure by Synergy in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. The properties evaluated by Ryder Scott represent 100 percent of the total net proved liquid hydrocarbon reserves and 100 percent of the total net proved gas reserves of Synergy as of August 31, 2012.

The estimated reserves and future net income amounts presented in this report, as of August 31, 2012, are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the ending date of the period covered in this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized below.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold Interests of
Synergy Resources Corporation
As of August 31, 2012

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Net Remaining Reserves				
Oil/Condensate – Barrels	1,160,464	1,663,140	2,262,207	5,085,811
Gas – MCF	7,243,960	10,136,846	16,065,168	33,445,974
Income Data, $				
Future Gross Revenue	$ 120,801,855	$ 173,143,585	$ 243,516,439	$ 537,461,879
Deductions	21,098,920	48,535,722	116,798,472	186,433,114
Future Net Income (FNI)	$ 99,702,935	$ 124,607,863	$ 126,717,967	$ 351,028,765
Discounted FNI @ 10%	$ 57,797,059	$ 56,196,448	$ 34,889,944	$ 148,883,451

Liquid hydrocarbons are expressed in standard 42 gallon barrels. All gas volumes are reported on an "as sold basis" expressed in thousands of cubic feet (MCF) at the official temperature and pressure bases of Colorado, which are 60°F and 14.73 psia, respectively.

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package PHDWin Petroleum Economic Evaluation Software, a copyrighted program of TRC Consultants L.C. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, recompletion costs and development costs. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist, nor does it include any adjustment for cash on hand or undistributed income. Liquid hydrocarbon reserves account for approximately 78 percent and gas reserves account for the remaining 22 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income As of August 31, 2012
Discount Rate Percent	Total Proved
5	$218,720,582
8	$172,162,576
12	$130,007,796
15	$107,762,635

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "Petroleum Reserves Definitions" is included as an attachment to this report.

The various proved reserve status categories are defined under the attachment entitled "Petroleum Reserves Status Definitions and Guidelines" in this report. The proved developed non-producing reserves included herein consist of the shut in and behind pipe categories. The refrac cases are included in the behind pipe category.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves, and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Synergy's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward". The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserve estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

Synergy's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which Synergy owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserve evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserve quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserve category assigned by the evaluator. Therefore, it is the categorization of reserve quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely than not to be achieved." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserve category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserve categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserve categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves for the properties included herein were estimated by performance methods, analogy, or a combination of those methods. Approximately 98 percent of the proved producing reserves attributable to producing wells and/or reservoirs were estimated by performance methods**.** These performance methods include decline curve analysis which utilized extrapolations of historical production and pressure data available from Synergy through August 2012 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Synergy or obtained from public data sources and were considered sufficient for the purpose thereof. The remaining 2 percent of the proved producing reserves were estimated by analogy. This method was used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserve estimates was considered to be inappropriate.

Approximately 100 percent of the proved developed non-producing and undeveloped reserves included herein were estimated by the analogy method. The analogy method utilized pertinent well data furnished to Ryder Scott by Synergy or which we have obtained from public data sources that were available through August 2012.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data that cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Synergy has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by Synergy with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, product prices based on the SEC regulations and adjustments or differentials to product prices. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Synergy. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Synergy. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the ending date of the period covered in this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations, exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

Synergy furnished us with the above mentioned average prices in effect on August 31, 2012. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark prices" and "price reference" used for the geographic area included in the report.

The product prices that were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as "differentials." The differentials used in the preparation of this report were furnished to us by Synergy.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the "average realized prices." The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves for the geographic area and presented in accordance with SEC disclosure requirements for the geographic area included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
Colorado	Oil/Condensate	WTI Cushing	$94.34/BBL	$86.68/BBL
	Gas	Henry Hub	$ 2.93/MMBTU	$ 3.76/MCF

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by Synergy and are based on the operating expense reports of Synergy and include only those costs directly applicable to the leases or wells. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by Synergy. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by Synergy and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished by Synergy were reviewed by us for their reasonableness using information furnished by Synergy for this purpose. Synergy's estimates of zero abandonment costs after salvage value for all properties were used in this report. Ryder Scott has not performed a detailed study of the abandonment costs or the salvage value and makes no warranty for Synergy's estimate.

The proved developed non-producing and undeveloped reserves in this report have been incorporated herein in accordance with Synergy's plans to develop these reserves as of August 31, 2012. The implementation of Synergy's development plans as presented to us and incorporated herein is subject to the approval process adopted by Synergy's management. As the result of our inquiries during the course of preparing this report, Synergy has informed us that the development activities included herein have been subjected to and received the internal approvals required by Synergy's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Synergy. Additionally, Synergy has informed us that they are not aware of any legal, regulatory, political or economic obstacles that would significantly alter their plans.

Current costs used by Synergy were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over seventy years. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

We are independent petroleum engineers with respect to Synergy. Neither we nor any of our employees have any interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for preparing the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Synergy.

Synergy makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Synergy has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3 of Synergy of the references to our name as well as to the references to our third party report for Synergy, which appears in the August 31, 2012 annual report on Form 10-K of Synergy. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Synergy.

We have provided Synergy with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Synergy and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

[seal]

RYDER SCOTT COMPANY, L.P.

/s/ Thomas E. Venglar
Thomas E. Venglar, P.E.
Colorado License No. 28846
Senior Petroleum Engineer

Approved:

/s/ James L. Baird
James L. Baird, P.E.
CO License No. 41521
Managing Senior Vice President

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Thomas E. Venglar was the primary technical person responsible for overseeing the estimate of the future net reserves and income.

Mr. Venglar, an employee of Ryder Scott Company, L.P. (Ryder Scott) beginning in 2006, is a Senior Petroleum Engineer responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies. Before joining Ryder Scott, Venglar served in a number of engineering positions with Grynberg Petroleum Company and Anadarko Petroleum Corporation. For more information regarding Mr. Venglar's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Experience/Employees.

Venglar earned a Bachelor of Science degree in Petroleum Engineering from Texas A&M University in 1979 and is a registered Professional Engineer in the state of Colorado. He is also a member of the Society of Petroleum Engineers.

Based on his educational background, professional training and more than 30 years of practical experience in the estimation and evaluation of petroleum reserves, Venglar has attained the professional qualifications as a Reserves Estimator and Reserves Auditor as set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.