DIVERSIFIED RESOURCES INC.

FORM 10-K
(Annual Report)

Filed 02/16/16 for the Period Ending 10/31/15

Address	1789 W. LITTLETON BLVD.
	LITTLETON, CO 80120
Telephone	303-797-5417
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Industry	Gold & Silver
Sector	Basic Materials
Fiscal Year	10/31

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 October 31, 2015

OR

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

For the transition period from ______________________ to ______________________

Commission file number: **333-175183**

DIVERSIFIED RESOURCES, INC.
(Exact name of registrant as specified in its charter)

NEVADA	**98-0687026**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1789 W. Littleton Blvd., Littleton, CO	**80120**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: **(303) 797-5417**

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

Title of each class	Name of each exchange on which registered
Common Stock	None

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

None
(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.

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 whether 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 was $7,181,437 based upon the closing sale price of the registrant's common stock of $0.31 on April 30, 2015 as reported by the OTC Market Group. 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 February 5, 2016, the Registrant had 43,248,636 issued and outstanding shares of common stock.

TABLE OF CO NT ENTS

As used in this document, "the Company", "Diversified", "we", "us" and "our" refer to Diversified Resources, Inc. and its consolidated subsidiaries.

Abbreviations or definitions of certain terms commonly used in the oil and gas industry and in this Form 10-K can be found in the "Glossary of Abbreviations and Terms".

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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;
- Changes in the supply of and demand for oil, NGL and natural gas
- Political instability or armed conflicts in major oil and natural gas producing regions
- Actions taken by OPEC
- 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. BUS IN ESS

Overview

We were incorporated on March 19, 2009 in Nevada. In 2009, we leased two unpatented mining claims located in Esmeralda County, Nevada. In January 2011, we staked an additional twenty unpatented mining claims in the same area. According to the lease, the additional mining claims were subject to the lease and we agreed to pay the lessor annual royalty payments. We did not pay royalties of $10,000 and $25,000 which were due in 2012 and 2013 and we terminated the lease in November 2013.

On November 21, 2013 we acquired all of the outstanding shares of Natural Resource Group, Inc. ("NRG") in exchange for 14,558,150 shares of our common stock.

In connection with the acquisition:

- Paul Laird, Duane Bacon, Roger May, and Albert McMullin were appointed as our officers and/or directors;
- Philip F. Grey resigned as our officer;
- Mr. Grey sold 2,680,033 shares of our common stock to us for nominal consideration. The shares purchased from Mr. Grey were returned to the status of authorized but unissued shares; and
- NRG became our wholly owned subsidiary.

Unless otherwise indicated, all references to us include the operations of NRG.

Overview of Natural Resource Group

NRG was incorporated in Colorado in 2000 but was relatively inactive until December 2010.

In December 2010 NRG acquired oil and gas properties from Energy Oil and Gas, Inc. for 2,500,000 shares of its common stock and a promissory note in the principal amount of $360,000. As of October 31, 2015, the principal amount of this note was $107,070.

Included as part of the acquisition were:

Garcia Field

- leases covering 4,600 gross (4,600 net) acres,
- four wells which produce natural gas and naturals gas liquids;
- a refrigeration/compression plant which separates natural gas liquids from gas produced from the four wells; and
- one injection well;

Denver-Julesburg Basin

- leases covering 1,400 gross (1,400 net) acres,
- three shut-in wells which need to be recompleted; and
- three producing oil and gas wells.

Subsequent to December 2010 leases, covering 160 acres in the Garcia Field were sold and leases covering 960 acres in the Garcia Field expired.

Garcia Field

As a result of our acquisition of NRG, we have a 100% working interest (80% net revenue interest) in oil and gas leases covering 4,600 acres in the Garcia Field.

The Garcia Field is located in Las Animas County approximately 10 miles from Trinidad, Colorado. The Garcia Field was first discovered in 1940 when the Maldonado #1 well produced 500 mcf per day of gas from the Niobrara formation. A stripping plant separated natural gas liquids from the gas and was operational for eight years until the Maldonado #1 was plugged in 1948. Between 1978 and 1982 twenty wells were drilled, tested for initial production and shut-in. Since there was no natural gas transportation line in the area, the wells were never produced. Additionally, until Energy Oil and Gas acquired the field in 2005 no natural gas liquids were produced commercially. In 2003, the entire field was force plugged as required by the state of Colorado, except for three wells which Energy Oil and Gas acquired from the state. Energy Oil and Gas subsequently drilled two additional wells and installed a new separation plant. We installed new equipment at our refrigeration/compression plant, which increased the yield of natural gas liquids to 3.5 gallons per mcf.

The fifth well is used to re-inject the gas back into the Apishapa and Niobrara formations. Currently, our wells are not connected to a gathering line which is needed to transport the gas to commercial markets. Kinder Morgan (KM) has a transportation line approximately eight miles north of the field. We believe there is enough capacity in KM's transportation line to transport gas produced from our wells. In addition, the city of Raton, NM, is in need of gas and has a pipeline approximately 10 miles south of the field that connects to the city of Raton. However, to connect our wells to either of the lines, we will need to install a gathering system at an estimated cost of $1,000,000 which includes a tap fee.

The gas from our wells has a BTU content of approximately 1,500. It is our belief that there is a productive oil formation in the Garcia Field since, from data acquired throughout the United States, it is apparent that no 1500 BTU gas has ever been produced in an area not associated with oil production. Due to NG liquid prices, the field was shut in on October 31, 2015 and based on an impairment evaluation of the field the Company recorded impairment expense of $2,427,968 at October 31, 2015.

Denver/Julesburg Basin

As a result of our acquisition of NRG, we have a 100% working interest (80% net revenue interest) in oil and gas leases covering 920 acres in the Denver/Julesburg ("D-J") Basin and the working interest and net revenue interests in the wells shown below:

Well Name	Working Interest	Net Revenue Interest
Shannon Roberts 1	75%	58.50%
Shannon Roberts 2-3-4	100%	78.00%
Lewton F Unit	100%	84.00%
UPPR Nichols	100%	85.00%

The reservoir rocks in the D-J Basin are Cretaceous sandstones, shales, and limestones deposited under marine conditions in the Western Interior Seaway. The oil and gas is contained within Cretaceous formations in the deepest part of the Basin, where the rocks were subject to enough heat and pressure to generate oil and gas from organic material in the rock. Most of the producing formations are considered “tight,” having low natural permeability.

The D-J Basin was one of the first oil and gas fields where extensive hydraulic fracturing was performed routinely and successfully on thousands of wells.

In 2009, the US Energy Information Administration listed the Wattenberg Field (a primary field within the D-J Basin) as the 10th largest gas field in the United States in terms of remaining proved gas reserves, and 13th in remaining proved oil/condensate reserves.

Major operators in the field include Noble Energy, Anadarko Petroleum Corporation, Continental, Whiting Petroleum, and Encana.

We plan to hydraulically fracture our wells in the D-J Basin at a cost of approximately $50,000 per well, once the moratorium on hydraulic fracturing is lifted by the city of Broomfield, CO. Hydraulic fracturing involves the process of pumping a mixture into a formation to create pores and fractures, thereby improving the porosity of the formation and increasing the flow of oil and gas. The mixture consists primarily of water and sand, with nominal amounts of other ingredients. This mixture is injected into wells at pressures of 4,500-6,000 pounds per square inch.

In 2013 we acquired a 640 acre lease (100% working interest, 80% net revenue interest) in the D-J Basin.

During the twelve months ending October 31, 2016, we plan to drill one vertical well at a cost of approximately $750,000.

Horseshoe - Gallup Field

On October 14, 2014, we acquired approximately 98% of the outstanding shares of BIYA Operating, Inc. (“BIYA”) for cash of $174,000, 900,000 restricted shares of our common stock having a value of approximately $900,000, a promissory note in the principal amount of approximately $1,860,000 (subject to adjustment for unknown liabilities) and the assumption of liabilities of BIYA in the approximate amount of $2,000,000. The note will be effective when certain leases covering Indian tribal lands have been issued. The note will bear interest at 5% a year and will be payable in October 2016.

Included as part of the acquisition were:

- 48 producing oil and gas wells, all of which we operate,
- leases covering approximately 10,000 gross and net acres, and
- miscellaneous equipment.

BIYA has oil and gas leases covering approximately 10,100 acres and 48 producing wells. The majority of the leased acreage and producing wells are on Mountain Ute tribal land and are leased under an operating agreement with the tribe. Under the agreement, BIYA is to drill 3 wells by April 2016 and 2 additional wells by April 2017 and April 2018, each. After April 2018, BIYA is required to drill 1 well per year. Per the agreement, if BIYA drills and completes a well, and establishes production from that well, it will own a lease of that well plus the applicable well spacing unit acreage surrounding that well, ranging from 40 acres to 320 acres based on the formation drilled, from the date of filing an application for permit to drill and for as long as Hydrocarbons are produced in paying quantities. These leases carry a royalty between 12.5% and 20%.

During the twelve months ending October 31, 2016, we plan to:

- rework 50 producing and shut-in wells at a total cost of approximately $400,000
- drill 5 new well at a net cost of approximately $150,000 per well

On January 29, 2015, we entered into a participation agreement with Palo Petroleum, Inc. ("Palo"), where Palo acquired the right to participate in all of our future operations in the Horseshoe Gallup Field, not related to the existing wells or existing production, but including the drilling of any future wells. Palo also has the right to participate in such future operations as a 40.00% of 8/8 Working Interest owner on a heads-up or non-promoted basis.

In addition, we entered into an Area of Mutual Interest Agreement ("AMI") with Palo relating to all lands in San Juan County, New Mexico outside the Horseshoe Gallup Field. Under this agreement, Palo and us will be entitled to participate in up to 50% in any leasehold or fee mineral interest within the AMI which is acquired by either Palo or us.

On September 1, 2015, the Company executed a non-binding letter of intent ("LOI") with Bayou City Energy, L.P. ("BCE") to jointly form an entity ("DrillCo") for development drilling on the Company's San Juan Basin properties in northwestern New Mexico.

The LOI covers BCE's intent to fund a portion of 55 wells located across the Company's existing 10,000 gross acre leasehold, as well as any future wells drilled during the ensuing three years ("Expansion Phase") across an Area of Mutual Interest ("AMI") in the Four Corner's Uplift region of the San Juan Basin. The terms of the LOI call for the establishment and funding of an entity formed by the Company and BCE through which, BCE will fund between 50% and 90% of the wells' costs in exchange for a preferred return and reversionary economic interests. The drilling program is delineated into three phases a "Test Phase", a "Development Phase" and an "Expansion Phase". After a preferred return has been reached for BCE in each Phase, the Company's percentage of net revenues from the wells increases to between 65% and 85%, depending under which Phase the wells are drilled.

Completion of this agreement will depend upon a number of conditions, including, but not limited to: completion of due diligence, approval of the final terms of definitive agreements by BCE's Investment Committee and the Company, receipt of all necessary regulatory and third party consents and approvals, regulatory and permitting approval of all "Test Phase" wells and the successful fundraise by the Company of no less than $1,000,000.

Acquisition of Diversified Energy Services, Inc

On February 5, 2016, the Company entered into an Agreement to Exchange Securities of Diversified Energy Services, Inc. ("DESI") a Colorado based company. The Company issued 20,032,710 shares in exchange for all the outstanding shares of DESI and assumed DESI's liabilities at January 31, 2016.

DESI offers a full range of services to the Rocky Mountain energy and construction industries and is dedicated to becoming the "one call, last call" solution to a full range of oil field service needs. DESI offers Crane Service, Well Site Construction, Materials Handling and Disposal, Trucking Services, Equipment Operation, and Rigging to the energy industry in the Denver Julesburg Basin and the Rockies. DESI employs upwards of 140 highly qualified, safety focused professionals and operators.

DESI will operate as a wholly owned subsidiary of Diversified Resources and is not expected to experience any change in management, operations, policies or business practices.

Production, Drilling Activity and Oil and Gas Leases

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

	Years Ended October 31,	
	2015	2014
Production:		
Oil (Bbls)	13,980	1,827
Gas (Mcf)	1,995	3,134
Natural Gas Liquids (gallons)	-	53,360
Average sales price:		
Oil ($/Bbl [1])	$ 40.00	$ 83.90
Gas ($/Mcf [2])	$ 2.35	$ 4.79
Natural Gas Liquids ($/gal)	$ -	$ 0.99
Average production cost per BOE [3]	$ 42.40	$ 93.01

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. One barrel of natural gas liquids is assumed to equal 0.61 barrel of oil.

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. We did not have any drilling activities for the years ended October 31, 2015 and 2014. As of
January 31, 2016 we were not drilling or reworking any wells.

The following table shows, as of January 31, 2016, our producing wells, developed acreage, and undeveloped acreage, excluding service (injection and disposal) wells:

	Productive Wells		Developed Acreage		Undeveloped Acreage (1)	
Location	Gross	Net	Gross	Net	Gross	Net
New Mexico:						
Horseshoe Gallup Field	48	48	4,440	3,560	5,672	3,403
Colorado:						
Garcia Field	5	5	200	200	4,400	4,400
D-J Basin	4	3.75	160	128	760	608

(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 January 31, 2016 the status of our gross acreage:

Location	Held by Production	Not Held by Production
New Mexico		
Horseshoe Gallup Field	10,112	--
Colorado:		
Garcia Field	4,600	--
D-J Basin	280	640

Acres that are Held by Production remain in force so long as oil or gas is produced from one or more wells on the particular lease. Leased acres that 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
640	7/22/2016

Oil and Natural Gas Reserves

In accordance with current SEC rules, the average prices used in computing reserves at October 31, 2015 were $40.00 per bbl of oil and $2.35 per mcf of natural gas. These prices are based on the 12-month unweighted arithmetic average market prices for sales of oil and natural gas on the first calendar day of each month during fiscal 2015. The benchmark price of $40.00 per bbl of oil at October 31, 2015 versus $83.90 at October 31, 2014, was adjusted by lease for gravity, transportation fees and regional price differentials. The benchmark price of $2.35 per mcf of natural gas at October 31, 2015 versus $4.79 at October 31, 2014, was adjusted by lease for BTU content, transportation fees and regional price differentials.

For information concerning our costs incurred for oil and gas operations, net revenues from oil and gas production, estimated future net revenues attributable to our oil and gas reserves, present value of future net revenues discounted at 10% and changes therein, see Notes 13, 14, 15 and 16 to our consolidated financial statements included as part of this report.

The engineering reports with respect to our estimates of proved oil and gas reserves as of October 31, 2015 are based on evaluations prepared by MHA Petroleum Consultants ("MHA"), based in Denver, Colorado and are filed as Exhibit 99.1 to this annual report. Mr. John Seidle, vice president MHA, is responsible for overseeing the preparation of the reserve estimates and has a doctorate in mechanical engineering, is a member of the Society of Petroleum Engineers and has over 30 years of experience in the oil and gas industry.

Jubal Terry, our Vice President - Exploration is the technical person primarily responsible for overseeing the preparation of our reserve estimates. He has a Bachelor of Science degree in Geology and over 35 years of industry experience with positions of increasing responsibility in operations, acquisitions, geology and evaluations. He has worked in the area of geology, exploration and development most of his career and is a member of the Rocky Mountain Association of Geologists. He prepared the reserve report for our Garcia field, the results of which are included in the unaudited standardized measure disclosure in Note 15 and 16 to our consolidated financial statements. Mr. Terry reports directly to our President. The reserve estimates are reviewed and approved by the President and certain other members of senior management.

Management maintains internal controls designed to provide reasonable assurance that the estimates of proved reserves are computed and reported in accordance with rules and regulations provided by the SEC. As stated above, we retained MHA to prepare estimates of our oil and gas reserves. Management works closely with MHA, and is responsible for providing accurate operating and technical data for purpose of computing our reserves. Our Chief Executive Officer, Chief Financial Officer and Vice President – Exploration, with a combined experience of over 70 years in the oil and gas industry, reviews the final reserves estimate and consults with Mr. Seidle.

Numerous uncertainties exist in estimating quantities of proved reserves. Reserve estimates are imprecise and subjective and may change at any time as additional information becomes available. Furthermore, estimates of oil and gas reserves are projections based on engineering data. There are uncertainties inherent in the interpretation of this data as well as the projection of future rates of production. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment.

Actual future production, oil and gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves will most likely vary from the assumptions and estimates. Any significant variance could materially affect the estimated quantities and value of our oil and gas reserves, which in turn may adversely affect our cash flow, results of operations and the availability of capital resources.

Per the current SEC rules, the prices used to calculate our proved reserves and the present value of proved reserves set forth herein are made using the 12-month unweighted arithmetic average of the first-day-of-the- month price. All prices are held constant throughout the life of the properties. Actual future prices and costs may be materially higher or lower than those as of the date of the estimate. The timing of both the production and the expenses with respect to the development and production of oil and gas properties will affect the timing of future net cash flows from proved reserves and their present value. Except to the extent that 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.

We have not filed any oil or gas reserve estimates or included any such estimates in reports to any other federal or foreign governmental authority or agency during the year ended October 31, 2015, and no major discovery is believed to have caused a significant change in our estimates of proved reserves since that date.

Proved reserves are estimated reserves of crude oil (including condensate and natural gas liquids) and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those expected to be recovered through existing wells, equipment and operating methods. Proved undeveloped reserves are proved reserves that are expected to be recovered from new wells drilled to known reservoirs on undrilled acreage for which the existence and recoverability of such reserves can be estimated with reasonable certainty, or from existing wells on which a relatively major expenditure is required to establish production.

Our estimated proved oil and gas reserves and present value of estimated future net revenues from proved oil and gas reserves as of the years ended October 31, 2015 and 2014 are summarized below:

PROVED RESERVES

	October 31, 2015	October 31, 2014
Oil (Bbls):		
Proved developed – Producing	350,000	299,856
Proved undeveloped	1,537,400	1,432,256
Total	1,887,400	1,732,112
Natural gas (Mcf):		
Proved developed – Producing	-	51,298
Proved undeveloped	400,000	1,257,190
Total	400,000	1,308,488
NG Liquids (Gallons)		
Proved developed – Producing		
Proved undeveloped	-	6,890,814
Total		6,890,814
Future net cash flow (1)	$ 24,618,258	$ 62,891,348
Future net cash flows discounted at 10%	(12,766,202)	(31,944,372)
Standardized measure of discounted future net cash flows (PV – 10 value) (2)	$ 11,852,056	$ 30,946,976
Prices used in calculating reserves: (3)		
Oil (per Bbl)	$ 40.00	$ 83.90
Natural gas (per Mcf)	$ 2.35	$ 4.79
NGL (per Gallon)	$ -	$ 0.99

(1) In accordance with SEC requirement, the standardized measure of discounted future net cash flows was computed by applying 12-month average prices for oil and gas during the fiscal year to the estimated future production of proved oil and gas reserves, less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, less estimated future income tax expenses (based on year-end statutory tax rates, with consideration of future tax rates already legislated) to be incurred on pretax net cash flows less tax basis of the properties and available credits, and assuming continuation of existing economic conditions.

(2) The PV-10 Value represents the discounted future net cash flows attributable to our proved oil and gas reserves before income tax, discounted at 10% per annum, which is the most directly comparable GAAP financial measure. PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. Our reconciliation of this non- GAAP financial measure is shown in the table as the PV-10, less future income taxes, discounted at 10% per annum, resulting in the standardized measure of discounted future net cash flows. The standardized measure of discounted future net cash flows represents the present value of future cash flows attributable to our proved oil and natural gas reserves after income tax, discounted at 10%.

(3) These prices reflect adjustment by lease for quality, transportation fees and regional price differentials.

Oil and gas prices significantly impact the calculation of the PV-10 and the standardized measure of discounted future net cash flows. The present value of future net cash flows does not purport to be an estimate of the fair market value of the Company's proved reserves. An estimate of fair value would also take into account, among other things, anticipated changes in future prices and costs, the expected recovery of reserves in excess of proved reserves and a discount factor more representative of the time value of money and the risks inherent in producing oil and gas. Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The 10% discount factor used to calculate present value, which is required by Financial Accounting Standards Board ("FASB") pronouncements, may not necessarily be the most appropriate discount rate. The present value, no matter what discount rate is used, may be materially affected by assumptions as to timing of future production, which may prove to be inaccurate.

Future Operations

We plan to evaluate other undeveloped oil prospects and participate in drilling activities on those prospects which, in management's opinion, are favorable for the production of oil, gas and natural gas liquids. Initially, we plan to concentrate our activities in the Wattenberg fields in Colorado and the San Juan basin of New Mexico. Our strategy is to acquire prospects in or adjacent to existing fields with further development potential and minimal risk in the same area.

If we believe 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 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 wells on a prospect;
- purchase producing oil properties;
- enter into farm-in agreements with third parties. A farm-in agreement will obligate us to pay the cost of drilling, and if warranted completing a well, in return for a majority of the working and net revenue interest in the well; or
- enter into joint ventures with third party holders of mineral rights.

Our activities will primarily be dependent upon available financing.

Title to properties which may be acquired will be subject to one or more of the following: royalty, overriding royalty, carried, net profits, working and other similar interests and contractual arrangements customary in the oil industry; liens for current taxes not yet due; and other encumbrances. In the case of undeveloped properties, investigation of record title will be made at the time of acquisition. Title reviews will be obtained before commencement of drilling operations.

Although we normally obtain title reports for oil leases we acquire, we have not in the past, and may not in the future, obtain title opinions pertaining to leases. A title report shows the history of a particular oil and gas lease, as shown by the records of the county clerk and recorder, state oil or gas commission, or the Bureau of Land Management, depending on the nature of the lease. In contrast, in a title opinion, an attorney expresses an opinion as to the persons or persons owning interests in a particular oil and gas lease.

Government Regulation

Although the sale of oil and natural gas is not regulated, federal, state and local agencies have promulgated extensive rules and regulations applicable to oil and gas exploration, production and related operations. Most states, including Colorado and New Mexico, 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. These states also have statutes or regulations addressing conservation matters including provisions for the unitization or pooling of oil and gas properties, the establishment of maximum rates of production from oil wells and the regulation of spacing, plugging and abandonment of such wells. The statutes and regulations of these and other states limit the rate at which oil is produced from wells. The federal and state regulatory burden on the oil and gas industry increases costs of doing business and affects 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 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 work, 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 properties on which oil and gas activities have taken place.

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 management, we are in substantial compliance with current applicable environmental laws and regulations, and have no material commitments for capital expenditures to comply with existing environmental requirements. Nevertheless, changes in existing environmental laws and regulations or in interpretations thereof 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 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.

Certain studies have suggested that emission of certain gases, commonly referred to as "greenhouse gases," may be impacting the earth's climate. Methane, the primary component of natural gas, and carbon dioxide, a by-product of burning oil and natural gas, are examples of greenhouse gases. Various state governments and regional organizations are considering enacting new legislation and promulgating new regulations governing or restricting the emission of greenhouse gases from stationary sources such as oil and gas production equipment and operations. At the federal level, the EPA has already made findings and issued regulations that require operators to establish and report an inventory of greenhouse gas emissions.

Legislative and regulatory proposals for restricting greenhouse gas emissions or otherwise addressing climate change could require us to incur additional operating costs and could adversely affect demand for the sale of oil and natural gas. The potential increase in our operating costs could include new or increased costs to obtain permits, operate and maintain equipment and facilities, install new emission controls on equipment and facilities, acquire allowances to authorize greenhouse gas emissions and pay taxes related to greenhouse gas emissions. Even without federal legislation or regulation of greenhouse gas emissions, states may pursue the issue either directly or indirectly.

Restrictions on emissions of methane or carbon dioxide that may be imposed in various states could adversely affect the oil and gas industry. Moreover, incentives to conserve energy or use alternative energy sources as a means of addressing climate change could reduce demand for oil and natural gas.

Competition and Marketing

We are faced with strong competition from many other companies and individuals engaged in the energy business, some of which are very large, well-established energy companies with substantial capabilities and established earnings records. We may be at a competitive disadvantage in acquiring prospects since we must compete with these individuals and companies, many of which have greater financial resources and larger technical staffs.

Exploration for, and the production of, oil, gas and natural gas liquids 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 wells. Higher prices for products may result in competition among operators for drilling equipment, tubular goods and drilling crews which may affect our ability to expeditiously to drill, complete, recomplete and work-over wells.

The market for oil, gas and natural gas liquids is dependent upon a number of factors beyond our control, which at times cannot be accurately predicted. These factors include the extent of competitive domestic production and imports of oil, 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. As of October 31, 2015, our oil production was being sold to Suncor and Pacer Energy Marketing and natural gas sales were made to Kerr McGee.

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.

The market price for natural gas can be affected by supply and demand characteristics on a local basis. Customarily there are transportation fees, tap fees and price adjustments paid to purchasers of our natural gas. We are unable to predict the future prices we will receive for our production of natural gas.

Price volatility makes it difficult to budget and project the return on investment in exploration and development projects and to estimate with precision the value of producing properties that are owned or acquired by the Company. In addition, volatile prices often disrupt the market for oil and natural gas properties, as buyers and sellers have more difficulty agreeing on the purchase price of properties. Revenues, results of operations, reserves and capital availability may fluctuate significantly as a result of variations in oil and natural gas prices and production performance. Lower oil and natural gas prices may also trigger significant impairment write-downs on a portion of the Company's properties and negatively affect the Company's results of operations.

The Company's financial position, results of operations, access to capital and the quantities of oil and natural gas that may be economically produced would be negatively impacted if oil and natural gas prices decrease significantly for an extended period of time. The ways in which such price decreases could have a material negative effect include:

- cash flow would be reduced, decreasing funds available for capital expenditures employed to replace reserves and maintain or increase production
- future undiscounted and discounted net cash flows from producing properties would decrease, possibly resulting in impairment expense that may be significant
- certain reserves may no longer be economic to produce, leading to lower proved reserves, production and cash flow
- access to sources of capital, such as equity or long-term debt markets, could be severely limited or unavailable

Employees and Offices

As of January 31, 2016, we had five full-time employees and no part-time employees.

Our principal offices are located at 1789 W Littleton Blvd., Littleton, CO 80120. Our offices, consisting of approximately 2200 square feet, are leased on a month-to-month basis at a rate of $2,667 per month. Our Chief Executive Officer, Paul Laird, is a partner in the entity that owns the building in which we lease our offices.

We are a licensed oil and gas operator in Colorado. We are the operator of our wells in the Garcia Field, the Denver-Julesburg Basin and the Horseshoe Gallup Field.

Access to Company Reports

We file annual, quarterly and current reports, proxy statements and other information with the Securities and Exchange Commission ("SEC"). Please call the SEC at 1-800-SEC-0330 for information on the public reference room. The SEC maintains an internet website (www.sec.gov) that contains annual, quarterly and current reports, proxy statements and other information that issuers, including Diversified, file electronically with the SEC.

We also maintain an internet website at www.diversifiedresourcesinc.com. In the Investor Relations section, our website contains our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and other reports and amendments to those reports. We post these reports on our website as soon as reasonably practicable after they are electronically filed with the SEC. Information on our website is not incorporated by reference into this Form 10-K and should not be considered part of this report or any other filing that we make with the SEC. Any of these corporate documents as well as any of the SEC filed reports are available in print free of charge to any stockholder who requests them. Requests should be directed to investor relations by mail to 1789 W Littleton Blvd, Littleton, CO 80120.

ITEM 1A. RISK FA CTORS

Not applicable.

ITEM 1B. UNRESOLVED ST AFF COMMENTS

Not applicable.

ITEM 2. PROP ER TIES

See Item 1 of this report.

ITEM 3. LEGAL PR OCEEDINGS

None.

ITEM 4. MINE S AFETY DISCLOSURES

Not applicable.

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

Since November 2012, our common stock has been quoted on the OTCQB tier of the OTC Markets Group under the symbol "DDRI". However, our common stock did not begin to trade until July 2013. The following shows the reported high and low prices for our common stock, based on information provided by the OTCQB, for the periods indicated. The over-the-counter market quotations reflect inter-dealer prices, without retail mark-up, mark-down or commission and may not necessarily represent actual transactions.

Quarter Ended	High	Low
January 31, 2014	$ 1.30	$ 0.70
April 30, 2014	$ 2.25	$ 0.80
July 31, 2014	$ 1.50	$ 1.10
October 31, 2014	$ 2.25	$ 0.70
January 31, 2015	$ 1.45	$ 0.38
April 30, 2015	$ 0.85	$ 0.25
July 31, 2015	$ 0.52	$ 0.28
October 31, 2015	$ 0.45	$ 0.29

Holders of our common stock are entitled to receive dividends as may be declared by the Board of Directors. Our Board of Directors is not restricted from paying any dividends but is not obligated to declare a dividend. No cash dividends have ever been declared and it is not anticipated that cash dividends will ever be paid. We currently intend to retain any future earnings to finance future growth. Any future determination to pay dividends will be at the discretion of the board of directors and will depend on our financial condition, results of operations, capital requirements and other factors the board of directors considers relevant.

Our Articles of Incorporation authorize our Board of Directors to issue up to 50,000,000 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 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 management. In addition, our Articles of Incorporation authorize our Board of Directors to issue up to 450,000,000 shares of common stock.

As of February 5, 2015, we had approximately 235 shareholders of record and 43,248,636 outstanding shares of common stock.

ITEM 6. SELECTED FINANC IA L DATA

Not applicable

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL C ON DITION AND RESULTS OF OPERATIONS

The following discussion is intended to provide information relevant to an understanding of our financial condition, changes in our financial condition and our results of operations and cash flows and should be read in conjunction with our consolidated financial statements and notes thereto included elsewhere in this Form 10-K.

Results of Operations

We were incorporated in Nevada in 2009, but we were relatively inactive until November 2013.

On November 21, 2013 we acquired 100% of the outstanding shares of Natural Resources Group, Inc. ("NRG") in exchange for 14,558,150 shares of our common stock.

Although from a legal standpoint, we acquired NRG on November 21, 2013, for financial reporting purposes our acquisition of NRG constituted a recapitalization, and the acquisition was accounted for similar to a reverse merger, whereby NRG was deemed to have acquired us.

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

Year ended October 31, 2015 compared to the year ended October 31 2014.

For the year ended October 31, 2015 we reported a net loss of $4,810,381 or $ 0.21 per share compared with a net income of $726,120 or $ 0.04 per share for the year ended October 31, 2014. The decrease of $5,536,501 or 762% principally arises from net impairment loss of $2,427,968 for the year ended October 31, 2015, an increase of $185,425 in general and administrative expenses due to having more employees and contractors, an increase of $210,129 in production tax and royalty expenses related to BIYA acquisition in October 2014 and a bargain purchase gain of $2,584,184 on the purchase of BIYA for the year ended October 31, 2014.

Operating revenues were $602,980 for the year ended October 31, 2015 compared with $161,623 for the year ended October 31, 2014. Operating revenues increased $441,357 or 273%, primarily due to the purchase of BIYA and the related production for the full twelve months compared to one month of October 2014, the increase in production was partially offset by the decrease in crude prices.

Exploration costs were $16,513 for the year ended October 31, 2015 compared with $41,802 for the year ended October 31, 2014, a decrease of $25,289 or 60% and is a result of a decrease in exploration related activities.

Lease operating expenses were $606,853 for the year ended October 31, 2015 compared with $290,588 for the year ended October 31, 2014. Lease operating expenses increased $316,265 or 109% for the year ended October 31, 2015 compared to the year ended October 31, 2014. Expenses related to BIYA, which was purchased in October 2014, increased by $444,550 due to full year of activity, the increase was partially offset by decrease in expenses related to Diversified.

General and administrative expenses were $1,695,792 for the year ended October 31, 2015 compared with $1,510,367 for the year ended October 31, 2014, an increase of $185,425 or 12%. Investor relations expense increased by $49,460 due to contract fee adjustment and cost related to being a public company, payroll expense increased by $169,487 due to a full year of expense and an increase in employee count and insurance expense increased by $66,023 due to an increase in rates and employee count.

Depreciation expense was $179,347 for the year ended October 31, 2015 compared with $27,895 for the year ended October 31, 2014, an increase of $151,452 or 543% and is a result of increased equipment in 2015 compared to 2014 and full year of depreciation on the assets acquired through purchase of BIYA.

Depletion expense was $88,287 for the year ended October 31, 2015 compared with $34,475 for the year ended October 31, 2014, an increase of $53,812 or 156% and is primarily related to full year of production from the BIYA purchase.

Production tax and royalty expense was $240,354 for the year ended October 31, 2015 compared with $30,225 for the year ended October 31, 2014, an increase of $210,129 or 695% and is primarily related to a full year of production and related royalty and taxes from the BIYA purchase.

Interest expense was $127,458 for the year ended October 31, 2015 compared with $60,281 for the year ended October 31, 2014, an increase of $67,177 or 111%. The increase is directly attributable to the increased amount of loans outstanding during 2015 compared to 2014.

The Company recorded an impairment expense of $2,427,968 for the year ended October 31, 2015. No such expense was recorded in 2014.

The Company recorded a bargain purchase gain, net of related taxes, of $2,584,184 on the purchase of BIYA in October 2014. No such gain was recorded in 2015.

The factors that will most significantly affect future operating results will be:

- the sale prices of crude oil, natural gas and natural gas liquids;
- the ability to transport natural gas produced from our wells;
- the amount of production from wells which produce oil, gas and gas liquids in which the Company has an interest;
- lease operating expenses;
- the availability of drilling rigs, drill pipe and other supplies and equipment required to drill and complete oil wells; and
- corporate overhead costs.

Revenues will also be significantly affected by the Company’s ability to maintain and increase oil and gas production.

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

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 primary use of capital has been for the exploration, development and acquisition of oil and natural gas properties. Our future success in developing proved reserves and production will be highly dependent on capital resources available to us.

As shown in the accompanying financial statements, we have incurred significant operating losses since inception aggregating $(7,092,714) and have negative working capital of $979,538 at October 31, 2015. As of October 31, 2015, we had limited financial resources. These factors raise substantial doubt about our ability to continue as a going concern. Our ability to achieve and maintain profitability and positive cash flow is dependent upon our ability to locate and operate profitable oil and gas properties, generate revenue from planned business operations, and control exploration costs. We plan to fund our future operations by joint venturing, obtaining additional financing, and attaining additional commercial production. However, there is no assurance that we will be able to obtain additional financing from investors or private lenders, or that additional commercial production can be attained.

Our sources and (uses) of funds for the years ended October 31, 2015 and 2014 are summarized below:

	Years Ended	
	October 31, 2015	October 31, 2014
Net cash (used in) operating activities	$ (2,259,990)	$ (2,505,800)
Purchase of property and equipment	(114,031)	(148,590)
Purchases of oil and gas properties	(32,000)	(25,410)
Proceeds from the sale of common stock	663,720	2,929,646
Proceeds from the sale of preferred stock	280,000	-
Proceeds from notes payable	1,329,166	-
Payments on notes payable	(54,213)	(110,295)
Net increase (decrease) in cash	$ (187,348)	$ 139,621

As of January 31, 2016 operating expenses were approximately $113,000 per month, which amount includes salaries and other corporate overhead, but excludes:

- expenses associated with drilling, completing or reworking wells, and
- lease operating and interest expenses.

We estimate our capital requirements for the twelve months ending October 31, 2016 are as follows:

● Drilling, completing, and fracturing wells	$ 1,500,000

Any cash generated by operations, after payment of general, administrative and lease operating expenses, will be used to drill and, if warranted, complete oil and gas wells, acquire oil and gas leases covering lands which are believed to be favorable for the production of oil, gas, and natural gas liquids, and to fund working capital reserves. The Company's capital expenditure plans are subject to periodic revision based upon the availability of funds and expected return on investment.

It is expected that the Company's principal source of cash flow will be from the sale of crude oil, natural gas and natural gas liquids 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 the Company to finance operations to a greater extent with internally generated funds, may allow the Company to obtain equity financing more easily or on better terms. However, price increases heighten the competition for oil 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 hydrocarbon prices (i) will reduce cash flow which in turn will reduce the funds available for exploring and replacing reserves, (ii) will 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 prospects which have reasonable economic terms, (iv) may cause the Company to allow leases to expire based upon the value of potential reserves in relation to the costs of exploration, (v) may result in marginally productive wells being abandoned as non-commercial, and (vi) may increase the difficulty of obtaining financing. However, price declines reduce the competition for oil properties and correspondingly reduce the prices paid for leases and prospects.

The Company plans to generate profits by acquiring, drilling and/or completing productive wells. However, the Company plans to obtain the funds required to drill, and if warranted, complete new wells with any net cash generated by operations, through the sale of securities, from loans from third parties or from third parties willing to pay the Company's share of the cost of drilling and completing the wells as partners/participants in the resulting wells. The Company does not have any commitments or arrangements from any person to provide it with any additional capital. The Company may not be successful in raising the capital needed to drill oil or gas wells. Any wells which may be drilled may not produce oil or gas.

Other than as disclosed above, we do not know of any:

- Trends, demands, commitments, events or uncertainties that will result in, or that are reasonably likely to result in, any material increase or decrease in liquidity; or
- Significant changes in expected sources and uses of cash.

Contractual Obligations

Our material future contractual obligations as of October 31, 2015 were as follows:

	Total	10/31/16	10/31/2017	Thereafter
	$ 3,924,810	426,702	3,498,108	$ -

Alternative Capital Resources

Although we have primarily used cash from operating activities and the sales of our securities as our primary capital resources, we have in the past, and may in the future, use alternative capital resources. These could include joint ventures, carried working interests and the sale of assets.

Critical Accounting Policies

See Note 1 to the financial statements included as part of this report for a description of our critical accounting policies and a discussion of our ability to continue as a going concern.

Recent Accounting Pronouncements

We do not believe that any recently issued accounting pronouncements will have a material impact on our financial position, results of operations or cash flows.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLO SU RE ABOUT MARKET RISKS

Commodity Risk

At October 31, 2015, we had not entered into any hedge arrangements, commodity swap agreements, commodity futures, options or other similar agreements relating to crude oil and natural gas.

Credit Risk

Credit risk is the risk of loss as a result of nonperformance by other parties of their contractual obligations. Our primary credit risk is related to oil and gas production sold to various purchasers and the receivables are generally not collateralized. At October 31, 2015, our largest credit risk associated with any single purchaser was $23,054. We have not experienced any significant credit losses.

Energy Price Risk

Our most significant market risk is the pricing for natural gas and crude oil. Our financial condition, results of operations, and capital resources are highly dependent upon the prevailing market prices of, and demand for, oil and natural gas. Prices for oil and natural gas fluctuate widely. We cannot predict future oil and natural gas prices with any certainty. Historically, the markets for oil and gas have been volatile, and they are likely to continue to be volatile. Factors that can cause price fluctuations include the level of global demand for petroleum products, foreign supply of oil and gas, the establishment of and compliance with production quotas by oil-exporting countries, weather conditions, the price and availability of alternative fuels and overall political and economic conditions in oil producing countries. Declines in oil and natural gas prices will materially and adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Changes in oil and gas prices impact both estimated future net revenue and the estimated quantity of proved reserves. Any reduction in reserves, including reductions due to price fluctuations, can reduce the borrowing base under our revolving credit facility and adversely affect the amount of cash flow available for capital expenditures and our ability to obtain additional capital for our acquisition, exploration and development activities. In addition, an additional noncash write-down of our oil and gas properties could be required if prices declined significantly, even if it is only for a short period of time.

Similarly, any improvements in oil and gas prices can have a favorable impact on our financial condition, results of operations and capital resources. Our financial results are more sensitive to movements in oil prices because most of our production and reserves are oil.

ITEM 8. FINANCIAL STATEMENTS AND SUPPL EM ENTARY DATA

See the financial statements and accompanying notes included with this report.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL D ISCLOSURE

Please see our 8-K report filed on January 29, 2015.

ITEM 9A. CONTROLS AND PROCE DU RES

Disclosure Controls and Procedures

An evaluation was carried out under the supervision and with the participation of our management, including our Principal Executive and 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 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 Principal Executive and Financial Officer, or persons performing similar functions, as appropriate, to allow timely decisions regarding required disclosure. Based on that evaluation, management concluded that, as of October 31, 2015, our disclosure controls and procedures were not effective, for the same reasons our internal control over financial reporting was not effective.

Management's Report on Internal Control over Financial Reporting

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 our Principal Executive and 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.

Our Principal Executive and the Financial Officer evaluated the effectiveness of our internal control over financial reporting as of October 31, 2015 based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, or the COSO 2013 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 has significant deficiencies. In connection with the preparation of our financial statements for the year ended October 31, 2015 certain material weaknesses in internal control became evident to management, including:

1. We do not have an audit committee;
2. We did not have the proper segregation of duties with respect to our finance and accounting functions due to limited personnel. During the year ended October 31, 2015 we had independent contractors that performed nearly all aspects of our financial reporting process, including but not limited to, preparation of underlying account records and systems, the posting and recording of journal entries and the preparation of the financial statements. Accordingly, this created certain incompatible duties and a lack of review over the financial reporting process that would likely result in a failure to detect errors in spreadsheets, calculations or assumptions used to compile the financial statements and related disclosures as filed with the SEC. These control deficiencies could result in a material misstatement of our interim or annual financial statements that would not be prevented or detected; and
3. Our corporate governance activities and processes are not formally documented.

As a result of the aforementioned deficiencies, our Principal Executive and Financial Officer concluded that the design and operation of our disclosure controls and procedures was not effective and that our internal control over financial reporting was not effective.

We intend to take appropriate and reasonable steps to make the necessary improvements to remediate these deficiencies. Since the acquisition of Natural Resource Group, Inc. on November 21, 2013, the board, as a whole, has been acting as the audit committee and independent board members constitute the compensation committee. We have adopted a code of ethics and other procedures and changes in our internal controls in response to the requirements of Sarbanes Oxley § 404. During the fiscal year ending October 31, 2016, we will continue to implement appropriate changes as they are identified, including changes to remediate the significant deficiencies in our internal controls. There can be no guarantee that we will be successful in making these changes as they may be considered cost prohibitive.

Changes in Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting that occurred during the quarter ended October 31, 2015 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER IN FO RMATION

None.

P AR T III

ITEM 10. DIRECTORS, EXECUT IV E OFFICERS AND CORPORATE GOVERNANCE

Our current officers and directors are listed below. Directors are generally elected at an annual shareholders' meeting and hold office until the next annual shareholders' meeting, or until their successors are elected and qualified. Executive officers are elected by directors and serve at the board's discretion.

Name	Age	Position
Paul Laird	59	Chief Executive Officer, Principal Financial and Accounting Officer and a Director
Duane Bacon	78	Chief Operating Officer and a Director
Roger May	59	Director
Albert McMullin	58	Director

On November 21, 2013, we acquired all of the outstanding shares of NRG in exchange for 14,558,150 shares of our common stock. In connection with this transaction, Paul Laird, Duane Bacon, Roger May and Albert McMullin were appointed as our officers and/or directors.

The principal occupations of our officers and directors during the past several years are as follows:

Paul Laird was appointed our Chief Executive Officer and a director on November 21, 2013. Since 1997, Mr. Laird has been the Chief Executive Officer and a Director of NRG. Between 2004 and 2009 Mr. Laird was the Chief Executive Officer of New Frontier Energy, Inc. Mr. Laird has over 30 years of experience in the Rocky Mountain oil and gas industry.

Duane Bacon was appointed as our Chief Operating Officer and a director on November 21, 2013. Since December, 2010 Mr. Bacon has been the Chief Operating Officer of NRG. From 2000 to 2010, Mr. Bacon has been the President of Energy Oil and Gas, Inc. a private exploration and production company located in Longmont, Colorado.

Roger May was appointed as one of our directors on November 21, 2013. Since 2010, Mr. May has been a director of NRG. Since 2005 Mr. May has been the Chief Executive Officer of RM Advisors, LLC, a firm that consults with development-stage companies in the areas of capital formation and corporate structure. Mr. May has over 25 years of experience in the financial industry with Rauscher Pierce and Schneider Securities.

Albert McMullin was appointed as one of our directors on November 21, 2013. He has been a director of NRG since 2011. Since 2010 he has been a senior Vice President of All American Oil and Gas Company, a firm focusing on enhanced oil recovery in California and Texas. Between 2006 and 2010 Mr. McMullin was the President of Standard Investment Company, a firm which provided consulting services to development stage companies. He has over 35 years of experience in the energy field and has worked for Exxon, Atlantic Richfield and United Gas Pipeline.

The basis for the conclusion that each current director is qualified to serve as a director is shown below.

Name	Reason
Paul Laird	Oil and gas exploration and development experience
Duane Bacon	Oil and gas exploration and development experience
Roger May	Investment banking experience
Albert McMullin	Oil and gas exploration and development experience

Roger May and Albert McMullin are the members of our compensation committee. The Board of Directors serves as our audit committee.

Mr. May and Mr. McMullin, are independent, as that term is defined in Section 803 A(2) of the NYSE MKT Company Guide.

ITEM 11. EXECUTIVE COMPE NS ATION

The following table summarizes the compensation received by our principal executive and financial officers during the two years ended October 31, 2015.

Name and Principal Position	Fiscal Year	Salary (1)	Bonus (2)	Restricted Stock Awards (3)	Option Awards (4)	Other Annual Compensation (5)	Total
		$				$	$
Paul Laird	2015	208,000	--	--	--	--	208,000
Chief Executive Officer	2014	150,000	--	--	--	445	150,445
Duane Bacon	2015	68,500	--	--	--	--	68,500
Chief Operating Officer	2014	66,000	--	--	--	445	66,445

(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 value of the shares of restricted stock issued as compensation for services computed in accordance with ASC 718 on the date of grant.

(4) The value of all stock options computed in accordance with ASC 718 on the date of grant.

(5) All other compensation received that could not be properly reported in any other column of the table. Amounts in the table represent overriding royalties paid during 2014.

The following shows the amounts we expect to pay to our officers and directors during the twelve months ending October 31, 2016 and the amount of time these persons expect to devote to us.

Name	Projected Compensation	Percent of Time to be Devoted to the Company's Business
Paul Laird	$ 234,000	100%
Duane Bacon	$ 66,000	100%

We have an employment agreement with Paul Laird. Pursuant to the agreement, we will pay Mr. Laird $19,500 per month. The employment agreement with Mr. Laird can be terminated at any time by either party without cause.

We have an employment agreement with Duane Bacon. Pursuant to the agreement, we will pay Mr. Bacon $5,500 per month. The agreement with Mr. Bacon is terminable at any time without cause.

Stock Option and Stock Bonus Plans. We do not have any stock option plans, although we may adopt one or more of such plans in the future.

Long-Term Incentive Plans. We do not provide our officers or employees with pension, stock appreciation rights or long-term incentive plans.

Employee Pension, Profit Sharing or other Retirement Plans. We do not have a defined benefit, pension plan, profit sharing or other retirement plan, although we may adopt one or more of such plans in the future.

Other Arrangements . In 2011 we granted Paul Laird and Duane Bacon each a 1% overriding royalty on NRG's leases in the Garcia Field. In the discretion of our directors, we may in the future grant overriding royalty interests to other persons.

Compensation of Directors During Year Ended October 31, 2015. During the year ended October 31, 2015, we did not compensate our directors for acting as such.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OW NE RS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The following table shows the beneficial ownership of our common stock as of January 31, 2016 by (i) each person whom we know beneficially owns more than 5% of the outstanding shares of our common stock; (ii) each of our officers; (iii) each of our directors; and (iv) all the officers and directors as a group. Unless otherwise indicated, each owner has sole voting and investment powers over his shares of common stock. Unless otherwise indicated, beneficial ownership is determined in accordance with the Rule 13d-3 promulgated under the Securities Exchange Act of 1934, as amended, and includes voting or investment power with respect to shares beneficially owned.

Name and Address of Beneficial Owner	Number of Shares Beneficially Owned	Percentage of Class
Paul Laird 1789 W. Littleton Blvd Littleton, CO 80120	3,135,642	13.5%
Duane Bacon 5982 Heather Way Longmont, CO 80503	979,508(1)	4.22%
Roger May 2780 Indiana Street Golden, CO 80401	412,174	1.8%
Albert McMullin 4501 Merrie Lane Belaire, TX 77401	106,793(2)	.5%
All officers and directors as a group (four persons).	4,634,117	20.03%

(1) Shares are held in the names of Duane and Ruth Bacon.

(2) Shares are held in the name of partnerships controlled by Mr. McMullin.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, DIR EC TOR INDEPENDENCE

Our principal offices are located at 1789 W Littleton Blvd., Littleton, CO 80120. Our offices, consisting of approximately 2200 square feet, are leased on a month-to-month basis at a rate of $2,667 per month. Our Chief Executive Officer, Paul Laird, is a partner in the entity that owns the building in which we lease our offices.

In December 2010 NRG acquired oil and gas properties from Energy Oil and Gas, Inc. for 2,500,000 shares of NRG's common stock and a promissory note in the principal amount of $360,000. Duane Bacon, one of our officers and directors controlled Energy Oil and Gas, Inc. The balance due on the note is $107,000 at October 31, 2015.

In connection with our acquisition of NRG, the following officers and directors received shares of our common stock in the amounts shown below.

Name	Number of Shares
Paul Laird	3,135,642
Duane Bacon	979,508
Roger May	412,174(1)
Albert McMullin	106,793

(1) Mr. May received 128,498 shares of our common stock for his services in arranging our acquisition of NRG.

See Item 11 of this report for information concerning overriding royalty interests we granted to Paul Laird and Duane Bacon.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND S ER VICES

The following table shows the aggregate fees billed by Frazer & Deeter to us for the periods ending October 31, 2014 and 2015, respectively.

		2015		2014
Audit Fees	$	95,000	$	66,000
All Other Fees	$	-		2,950

Audit fees represent amounts invoiced for professional services rendered for the audit of our annual financial statements and the reviews of the financial statements included in our 10-Q reports.

P AR T IV

ITEM 15. EXH IB ITS, FINANCIAL STATEMENT SCHEDULES

Exhibit Number	Exhibit Name
3.1	Articles of Incorporation (1)
3.2	Bylaws (1)
31	Rule 13a-14(a) Certifications
32	Section 1350 Certifications
99.1	Report of MHA Petroleum Consultants, Independent Petroleum Engineer

(1) Incorporated by reference to the same exhibit filed with the Company's registration statement on Form S-1 (File No. 333-175183).
(2) Incorporated by reference to the same exhibit filed with the Company's report on Form 8-K (filed on November 22, 2013).

SIG NA TURES

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 16th day of February 2016.

DIVERSIFIED RESOURCES, INC.

By: */s/ Paul Laird*
Paul Laird, President

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/ Paul Laird Paul Laird	President, Principal Executive, Financial and Accounting Officer and a Director	February 16, 2016
/s/ Duane Bacon Duane Bacon	Director	February 16, 2016
/s/ Roger May Roger May	Director	February 16, 2016
/s/ Albert McMullin Albert McMullin	Director	February 16, 2016

Glossary of Abbr ev iations and Terms

The following are abbreviations and definitions of terms commonly used in the oil and gas industry and might be used in this report.

Bbl . One stock tank barrel, or 42 U.S. gallons of liquid volume, used herein in reference to crude oil, condensate or natural gas liquids hydrocarbons.

Bcf . One billion cubic feet of natural gas at standard atmospheric conditions.

BTU. British thermal unit.

Completion . The installation of permanent equipment for the production of oil or natural gas.

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

DD&A. Refers to depreciation, depletion and amortization of the Company's property and equipment.

Developed acreage . The number of acres which are allocated or assignable to producing wells or wells capable of production.

Development costs. Capital costs incurred in the acquisition, exploitation and exploration of proved oil and natural gas reserves divided by proved reserve additions and revisions to proved reserves.

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

Dry hole . A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Exploitation. The continuing development of a known producing formation in a previously discovered field. To make complete or maximize the ultimate recovery of oil or natural gas from the field by work including development wells, secondary recovery equipment or other suitable processes and technology.

Exploration. The search for natural accumulations of oil and natural gas by any geological, geophysical or other suitable means.

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

Extensions and discoveries . As to any period, the increases to proved reserves from all sources other than the acquisition of proved properties or revisions of previous estimates.

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

Formation. A layer of rock which has distinct characteristics that differs from nearby rock.

Gross acres or wells. Refers to the total acres or wells in which the Company owns any amount of working interest.

Lease. An instrument which grants to another (the lessee) the exclusive right to enter and explore for, drill for, produce, store and remove oil and natural gas from the mineral interest, in consideration for which the lessor is entitled to certain rents and royalties payable under the terms of the lease. Typically, the duration of the lessee's authorization is for a stated term of years and "for so long thereafter" as minerals are producing.

Mcf . One thousand cubic feet of natural gas at standard atmospheric conditions.

Mcfe. One thousand cubic feet equivalent of natural gas, calculated by converting oil to equivalent Mcf at a ratio of 6 Mcf for each Bbl of oil.

MMBtu . One million British thermal units of energy commonly used to measure heat value or energy content of natural gas.

Natural gas liquids ("NGLs") . Liquid hydrocarbons that have been extracted from natural gas, such as ethane, propane, butane and natural gasoline.

Net acres or wells. Refers to gross acres or wells multiplied, in each case, by the percentage interest owned by the Company.

Net production . Oil and gas production that is owned by the Company, less royalties and production due others.

Net revenue interest. An owner's interest in the revenues of a well after deducting proceeds allocated to royalty and overriding interests.

Oil . Crude oil or condensate.

Operator . The individual or company responsible for the exploration, development and production of an oil or natural gas well or lease.

Overriding royalty interest ("ORRI"). A royalty interest that is created out of the operating or working interest. Its term is coextensive with that of the operating interest from which it was created.

Pay zone. A geological deposit in which oil and natural gas is found in commercial quantities.

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

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed operating and production expenses and taxes.

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

Proved developed nonproducing reserves ("PDNP") . Reserves that consist of (i) proved reserves from wells which have been completed and tested but are not producing due to lack of market or minor completion problems which are expected to be corrected and (ii) proved reserves currently behind the pipe in existing wells and which are expected to be productive due to both the well log characteristics and analogous production in the immediate vicinity of the wells.

Proved developed producing reserves ("PDP"). Proved reserves that can be expected to be recovered from currently producing zones under the continuation of present operating methods.

Proved developed reserves. The combination of proved developed producing and proved developed nonproducing reserves.

Proved reserves. The estimated quantities of oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved undeveloped reserves ("PUD") . Proved 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.

PV-10. When used with respect to oil and natural gas reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses except for specific general and administrative expenses incurred to operate the properties, discounted to a present value using an annual discount rate of 10%.

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

Re-entry. Entering an existing well bore to redrill or repair.

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

Royalty . An interest in an oil and natural gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage, or of the proceeds of the sale thereof, but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

Shut in. A well suspended from production or injection but not abandoned.

Spacing. The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres (e.g., 640-acre spacing) and is often established by regulatory agencies.

Standardized measure of discounted future net cash flows . The discounted future net cash flows relating to proved reserves based on prices used in estimating the reserves, year-end costs, and statutory tax rates, and a 10% annual discount rate. The information for this calculation is included in the note regarding disclosures about oil and gas reserve data contained in the Notes to Consolidated Financial Statements included in this Form 10-K.

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

Unit. The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

Wellbore. The hole drilled by the bit that is equipped for crude oil or natural gas production on a completed well.
Also called well or borehole.

Working interest . An interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce oil and natural gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations. The share of production to which a working interest is entitled will be smaller than the share of costs that the working interest owner is required to bear to the extent of any royalty burden.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED P UB LIC ACCOUNTING FIRM

To the Shareholders and Board of Directors
Diversified Resources, Inc.

We have audited the accompanying consolidated balance sheets of Diversified Resources, Inc. (the "Company") as of October 31, 2015 and 2014, and the related consolidated statements of operations, changes in stockholders' equity and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of October 31, 2015 and 2014, and the results of their operations and cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 1 to the consolidated financial statements, the Company has an accumulated deficit and has incurred significant operating losses and has a working capital deficit. These factors raise substantial doubt about the Company's ability to continue as a going concern. Management's plans in regard to this matter are also discussed in Note 1. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

/s/ Frazier & Deeter, LLC

Atlanta, Georgia
February 16, 2016

Diversified Reso ur ces, Inc.
CONSOLIDATED BALANCE SHEETS

	October 31, 2015	October 31, 2014
ASSETS		
CURRENT ASSETS		
Cash	$ 21,706	$ 209,054
Accounts receivable, trade	67,189	130,495
Accounts receivable, other	313,989	-
Prepaid expenses	-	7,948
Total current assets	402,884	347,497
LONG-LIVED ASSETS		
Property and Equipment, net of accumulated depreciation of $322,281 and $149,957	1,846,111	1,904,403
Bonds and deposits	167,867	167,867
Oil and gas properties - proved (successful efforts method) net of accumulated depletion and impairment of $2,623,339 and $100,062	1,282,876	3,806,153
Oil and gas properties - proved undeveloped (successful efforts method)	1,241,724	1,209,724
Oil and gas properties - unproved (successful efforts method)	2,932,730	2,932,730
Total assets	$ 7,874,192	$ 10,368,374
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 387,028	$ 221,880
Accounts payable, related party	147,736	145,473
Current portion of notes payable	319,632	373,846
Note payable – related party	107,070	-
Accrued interest, related party	15,287	4,579
Accrued expenses	405,669	560,548
Total current liabilities	1,382,422	1,306,326
LONG TERM LIABILITIES		
Long term debt, related party	-	107,070
Long term debt	3,498,108	2,294,943
Asset retirement obligation	321,101	290,312
COMMITMENTS AND CONTINGENT LIABILITIES		-
STOCKHOLDERS' EQUITY		
Preferred stock, $0.001 par value 50,000,000 shares authorized: 301,000 and 0 shares issued and outstanding in 2015 and 2014, respectively	301	-
Common stock, $0.0001 par value, 450,000,000 shares authorized, 23,215,926 and 22,502,206 shares issued and outstanding in 2015 and 2014, respectively	23,216	22,502
Additional paid in capital	9,741,759	8,629,554
Accumulated deficit	(7,092,714)	(2,282,333)
Total stockholders' equity	2,672,562	6,369,723
Total liabilities and stockholders' equity	$ 7,874,192	$ 10,368,374

The accompanying notes are an integral part of the consolidated financial statements.

Diversified Resou rc es Inc.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended	
	October 31, 2015	October 31, 2014
Operating revenues		
Oil and gas sales	$ 602,980	$ 161,623
	602,980	161,623
Operating expenses		
Exploration costs, including dry holes	16,513	41,802
Lease operating expenses	606,853	290,588
General and administrative	1,695,792	1,510,367
Impairment of oil and gas properties	2,427,968	-
Depreciation expense	179,347	27,895
Depletion expense	88,287	34,475
Accretion expense	30,789	24,054
Production tax and royalty expense	240,354	30,225
Total operating expenses	5,285,903	1,959,406
(Loss) from operations	(4,682,923)	(1,797,783)
Other income (expense)		
Bargain purchase gain	-	2,584,184
Interest expense	(127,458)	(60,281)
Other income (expense), net	(127,458)	2,523,903
Net income (loss)	$ (4,810,381)	$ 726,120
Net income (loss) per common share		
Basic and diluted	$ (0.21)	$ 0.04
Weighted average shares outstanding		
Basic and diluted	23,074,893	18,792,650

The accompanying notes are an integral part of the consolidated financial statements.

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Diversified Resou rc es, Inc.
Consolidated Statement of Stockholders' Equity
Years Ended October 31, 2015 and 2014

	Common Stock $.001 Par Value		Preferred Stock $.001 Par Value		Additional		
	Shares	Amount	Shares	Amount	Paid-in Capital	Accumulated Deficit	Total
Balance October 31, 2013	14,558,150	$ 14,558	-	-	$ 4,734,143	$ (3,008,453)	$ 1,740,248
Recapitalization with Natural Resources Group, Inc.	5,250,000	5,250	-	-	(302,980)	-	(297,730)
Contribution of shares in connection with the acquisition	(2,680,033)	(2,680)	-	-	2,680	-	-
Forgiveness of related party debt and assumption of liabilities by former shareholder	-	-	-	-	297,741	-	297,741
Common stock issued for cash	4,474,089	4,474	-	-	2,925,172	-	2,929,646
Acquisition of BIYA	900,000	900	-	-	972,798	-	973,698
Net income for period	-	-	-	-	-	726,120	726,120
Balance October 31, 2014	22,502,206	22,502	-	-	8,629,554	(2,282,333)	6,369,723
Common stock issued for cash	663,720	664	-	-	663,056	-	663,720
Common stock issued for lease expense	50,000	50			22,450		22,500
Preferred stock issued for cash	-	-	280,000	280	279,720	-	280,000
Preferred stock issued for accrued interest			21,000	21	20,979		21,000
Warrants issued with debt	-	-	-	-	126,000	-	126,000
Net loss for period	-	-	-	-	-	(4,810,381)	(4,810,381)
Balance October 31, 2015	23,215,926	$ 23,216	301,000	$ 301	$ 9,741,759	$ (7,092,714)	$ 2,672,562

The accompanying notes are an integral part of the consolidated financial statements.

Diversified Resour ce s, Inc.
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended

	October 31, 2015	October 31, 2014
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ (4,810,381)	$ 726,120
Adjustments to reconcile net income (loss) to net cash (used in) operating activities:		
Interest paid with common stock	22,500	-
Bargain purchase gain	-	(2,584,184)
Depreciation expense	179,347	27,895
Depletion expense	88,287	34,475
Accretion expense	30,789	24,054
Impairment	2,427,968	-
Changes in assets and liabilities:		
Accounts receivable, trade	63,303	34,860
Accounts receivable, other	(313,989)	
Prepaid expense	7,948	11,924
Bonds and deposits	-	21,042
Accounts payable	165,148	2,731
Accounts payable - related parties	12,970	15,112
Accrued expenses	(133,880)	(819,829)
Net cash (used in) operating activities	(2,259,990)	(2,505,800)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash paid for oil and gas properties	(32,000)	(25,410)
Cash paid for purchase of property and equipment	(114,031)	(148,590)
Net cash (used in) investing activities	(146,031)	(174,000)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from sale of common stock	663,720	2,929,646
Proceeds from sale of preferred stock	280,000	-
Proceeds from notes payable	1,329,166	-
Payments on notes payable	(54,213)	(110,225)
Net cash provided by financing activities	2,218,673	2,819,421
INCREASE (DECREASE) IN CASH	(187,348)	139,621
BEGINNING BALANCE	209,054	69,433
ENDING BALANCE	$ 21,706	$ 209,054
Cash paid for interest	$ 32,144	$ 25,448
Non cash investing and financing activities:		
Acquisition of BIYA:		
Common stock issued	$ -	$ 900,000
Note payable issued	$ -	$ 1,860,000
Preferred stock issued for accrued interest	$ 21,000	$ -
Warrants issued with debt	$ 126,000	$ -

The accompanying notes are an integral part of the consolidated financial statements.

DIVERSIFIED RESO UR CES INC.
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
Years Ending October 31, 2015 and 2014

Note 1. Summary of Significant Accounting Policies

Organization

Diversified Resources Inc. ("the Company") was incorporated in the State of Nevada on March 19, 2009 to pursue mineral extraction in the United States.

On June 15, 2009 the Company leased two mining claims in Esmerelda County, Nevada, in the Dunfee Mine Area. The lease includes all additional claims within one mile of these claims. The term of the lease was for 20 years and was terminated during November 2013.

In November 2013, the Company entered into an agreement to exchange securities with Natural Resource Group, Inc. ("NRG"), an oil and gas exploration company, whereby the shareholders of NRG received 14,558,150 shares of the Company's common stock. In connection with this acquisition, the then President sold 2,680,033 shares of the Company's common stock to the Company for nominal consideration. The shares purchased from the President were returned to the status of authorized but unissued shares. Additionally, the former principals of the Company assumed all of the debts of the Company at the date of the exchange. The transaction was accounted for as a reverse acquisition or recapitalization whereby NRG was considered the accounting acquirer and the Company, the acquiree.

The Company has no interests in any unconsolidated entities, nor does it have any unconsolidated special purpose entities.

Going Concern

As shown in the accompanying consolidated financial statements, the Company has incurred significant operating losses since inception, has an accumulated deficit of ($7,092,714) and has negative working capital of $979,538 at October 31, 2015. As of October 31, 2015, the Company has limited financial resources. These factors raise substantial doubt about the Company's ability to continue as a going concern. The Company's ability to achieve and maintain profitability and positive cash flow is dependent upon its ability to locate profitable mineral properties, generate revenue from planned business operations, and control exploration costs. Management plans to fund its future operations by joint venturing, obtaining additional financing, and attaining additional commercial production. However, there is no assurance that the Company will be able to obtain additional financing from investors or private lenders, or that additional commercial production can be attained.

The consolidated financial statements do not include any adjustments to reflect the possible future effects on the recoverability and classification of assets or the amounts and classification of liabilities that may result from the possible inability of the Company to continue as a going concern.

Cash and Cash Equivalents

Cash and cash equivalents include all cash balances and any highly liquid investments with an original maturity of 90 days or less. The carrying amount approximates fair value due to the short maturity of these instruments.

Accounts Receivable

The Company records estimated oil and gas revenue receivable from third parties at its net revenue interest. The Company also reflects costs incurred on behalf of joint interest partners in accounts receivable. The Company uses the direct write-off method for bad debts; this method expenses uncollectible accounts in the year they become uncollectible. Any difference between this method and the allowance method is not material. Management periodically reviews accounts receivable amounts for collectability and adjusts for uncollectible receivables under the direct write-off method. The Company did not record any adjustment for uncollectible receivables in 2015 or 2014.

Use of Estimates

The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Estimates of oil and gas reserve quantities provide the basis for calculation of depletion, depreciation, and amortization, and impairment, each of which represents a significant component of the financial statements. Actual results could differ from those estimates.

Concentration of Credit Risk

Financial instruments that potentially subject the Company to concentrations of credit risk consist primarily of cash equivalents. The Company places its cash equivalents with a high credit quality financial institution. The Company periodically maintains cash balances at a commercial bank in excess of the Federal Deposit Insurance Corporation insurance limit of $250,000.

Stock-based compensation

ASC 718, *Stock Compensation* requires that all stock-based compensation be recognized as an expense in the financial statements and that such cost be measured at the grant date fair value of the award.

We record compensation and other charges related to the issuance of stock-based compensation awards at the fair value of the awards. Such awards can be comprised of stock, restricted stock and stock options.

We record the grant date fair value of stock-based compensation awards as an expense over the vesting period of the related stock options. In order to determine the fair value of the stock options on the date of grant, we use the Black-Scholes option-pricing model. Inherent in this model are assumptions related to expected stock-price volatility, option life, risk-free interest rate and dividend yield. Although the risk-free interest rates and dividend yield are less subjective assumptions, typically based on factual data derived from public sources, the expected stock-price volatility, forfeiture rate and option life assumptions require a greater level of judgment which makes them critical accounting estimates.

We use an expected stock price volatility assumption that is based on historical volatilities of our common stock and we estimate the forfeiture rate and option life based on historical data related to prior option grants, as we believe such historical data will be similar to future results.

Dependence on Oil and Gas Prices

As an independent oil and gas producer, our revenue, profitability and future rate of growth are substantially dependent on prevailing prices for natural gas and oil. Historically, the energy markets have been very volatile, and there can be no assurance that oil and gas prices will not be subject to wide fluctuations in the future. Prices for oil and natural gas have recently declined materially. Any continued and extended decline in oil or gas prices could have a material adverse effect on our financial position, results of operations, cash flows and access to capital and on the quantities of oil and gas reserves that we can economically produce.

Revenue Recognition

We recognize oil and gas revenue from interests in producing wells as the oil or gas is sold. Revenue from the purchase, transportation, and sale of natural gas is recognized upon completion of the sale and when transported volumes are delivered. We recognize revenue related to gas balancing agreements based on the sales method. Our net imbalance position at October 31, 2015 and 2014 was immaterial.

Accounting for Oil and Gas Activities

Successful Efforts Method We account for crude oil and natural gas properties under the successful efforts method of accounting. Under this method, costs to acquire mineral interests in crude oil and natural gas properties, drill and equip exploratory wells that find proved reserves, and drill and equip development wells are capitalized. Capitalized costs of producing crude oil and natural gas properties, along with support equipment and facilities, are amortized to expense by the unit-of-production method based on proved crude oil and natural gas reserves on a field-by-field basis, as estimated by our qualified petroleum engineers. Upon sale or retirement of depreciable or depletable property, the cost and related accumulated depreciation, depletion and amortization amounts are eliminated from the accounts and the resulting gain or loss is recognized. Repairs and maintenance are expensed as incurred.

Assets are grouped in accordance with the Extractive Industries - Oil and Gas Topic of the Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC). The basis for grouping is a reasonable aggregation of properties with a common geological structural feature or stratigraphic condition, such as a reservoir or field.

Depreciation, depletion and amortization of the cost of proved oil and gas properties are calculated using the unit-of-production method. The reserve base used to calculate depreciation, depletion and amortization for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves. With respect to lease and well equipment costs, which include development costs and successful exploration drilling costs, the reserve base includes only proved developed reserves. Estimated future dismantlement, restoration and abandonment costs, net of salvage values, are taken into account.

Proved Property Impairment We review individually significant proved oil and gas properties and other long-lived assets for impairment at least annually at year-end, or quarterly when events and circumstances indicate a decline in the recoverability of the carrying values of such properties, such as a negative revision of reserves estimates or sustained decrease in commodity prices. We estimate future cash flows expected in connection with the properties and compare such future cash flows to the carrying amount of the properties to determine if the carrying amount is recoverable. When the carrying amount of a property exceeds its estimated undiscounted future cash flows, the carrying amount is reduced to estimated fair value. Fair value may be estimated using comparable market data, a discounted cash flow method, or a combination of the two. In the discounted cash flow method, estimated future cash flows are based on management's expectations for the future and include estimates of future oil and gas production, commodity prices based on published forward commodity price curves as of the date of the estimate, operating and development costs, and a risk-adjusted discount rate. Our valuation of Garcia field resulted in impairment expense of $2,427,968 during the period ending October 31, 2015.

Unproved Property Impairment Our unproved properties consist of leasehold costs and allocated value to probable and possible reserves from acquisitions. We assess individually significant unproved properties for impairment on a quarterly basis and recognize a loss at the time of impairment by providing an impairment allowance. In determining whether a significant unproved property is impaired we consider numerous factors including, but not limited to, current exploration plans, favorable or unfavorable exploration activity on the property being evaluated and/or adjacent properties, our geologists' evaluation of the property, and the remaining months in the lease term for the property.

Exploration Costs Geological and geophysical costs, delay rentals, amortization of unproved leasehold costs, and costs to drill exploratory wells that do not find proved reserves are expensed as oil and gas exploration. We carry the costs of an exploratory well as an asset if the well finds a sufficient quantity of reserves to justify its capitalization as a producing well and as long as we are making sufficient progress assessing the reserves and the economic and operating viability of the well. Geological and geophysical costs were $16,513 and $41,802 for the years ended October 31, 2015 and 2014, respectively, and are included in Exploration Costs in the accompanying financial statements.

Asset Retirement Obligations Asset retirement obligations consist of estimated costs of dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. We recognize the fair value of a liability for an ARO in the period in which it is incurred when we have an existing legal obligation associated with the retirement of our oil and gas properties that can reasonably be estimated, with the associated asset retirement cost capitalized as part of the carrying cost of the oil and gas asset. The asset retirement cost is determined at current costs and is inflated into future dollars using an inflation rate that is based on the consumer price index. The future projected cash flows are then discounted to their present value using a credit-adjusted risk-free rate. After initial recording, the liability is increased for the passage of time, with the increase being reflected as accretion expense in the statement of operations. Subsequent adjustments in the cost estimate are reflected in the liability and the amounts continue to be amortized over the useful life of the related long-lived asset.

Net Income (Loss) per Common Share

Basic earnings (loss) per share are calculated by dividing net income (loss) by the weighted average number of common shares outstanding for the period. Diluted earnings (loss) per share are calculated by dividing net income (loss) by the weighted average number of common shares and dilutive common stock equivalents outstanding. During the periods when they are anti-dilutive, common stock equivalents, if any, are not considered in the computation.

Property and Equipment

Property and equipment consists of production buildings, furniture, fixtures, equipment and vehicles which are recorded at cost and depreciated using the straight-line method over the estimated useful lives of five to fifteen years. Property and equipment primarily consists of production equipment.

Maintenance and repairs are charged to expense as incurred.

Impairment of Long Lived Assets

The long-lived assets of the Company consist primarily of proved oil and gas properties and undeveloped leaseholds. The Company reviews the carrying values of its oil and gas properties and undeveloped leaseholds annually or whenever events or changes in circumstances indicate that such carrying values may not be recoverable. If, upon review, the sum of the undiscounted pretax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets, generally on a field-by-field basis. The fair value of impaired assets is determined based on quoted market prices in active markets, if available, or upon the present values of expected future cash flows. The impairment analysis performed by the Company may utilize Level 3 inputs.

The Company recorded impairment expense of $2,427,968 based on valuation of Garcia field for the year ending October 31, 2015. No such impairment was recorded for the years ended October 31, 2014.

Income Taxes

We compute income taxes in accordance with ASC Topic 740, *Income Taxes* . Under ASC 740, provisions for income taxes are based on taxes payable or refundable during each reporting period and changes in deferred taxes. Deferred income taxes may arise from temporary differences resulting from income and expense items reported for financial accounting and tax purposes in different periods. Deferred tax assets and liabilities are included in the financial statements at currently enacted income tax rates applicable to the period in which the deferred tax assets and liabilities are expected to be realized or settled. Also, the effect on deferred taxes of a change in tax rates is recognized in income in the period that includes the enactment date. Deferred taxes are classified as current or non-current depending on the classifications of the assets and liabilities to which they relate. Deferred taxes arising from temporary differences that are not related to an asset or liability are classified as current or non-current depending on the periods in which the temporary differences are expected to reverse. If available evidence suggests that it is more likely than not that some portion or all of the deferred tax assets will not be realized, a valuation allowance is required to reduce the deferred tax assets to the amount that is more likely than not to be realized. Future changes in such valuation allowance are included in the provision for deferred income taxes in the period of change.

We follow the guidance in ASC Topic 740-10, *Accounting for Uncertainty in Income Taxes* , which prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of tax positions taken or expected to be taken in a tax return. For those benefits to be recognized, a tax position must be more-likely-than-not to be sustained upon examination by taxing authorities. The amount recognized is measured as the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. The Company does not believe that any material uncertain tax positions exist at October 31, 2015.

Major Customers

Sales to major unaffiliated customers consisted of the following for the year ended October 31, 2015: Customer A accounted for approximately 95% of revenue.

Sales to major unaffiliated customers consisted of the following for the year ended October 31, 2014: Customer A accounted for approximately 54% of revenue, Customer B accounted for approximately 17%, Customer C accounted for approximately 13%, and Customer D accounted for approximately 11%.

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.

Recent Accounting Pronouncements

There were no recently issued or proposed accounting pronouncements which management believes will have a material effect on the Company's financial statements.

2. Oil and gas properties

Oil and gas properties consist of the following:

	October 31, 2015	October 31, 2014
Proved oil and gas properties	$ 3,906,215	$ 3,906,215
Proved undeveloped oil and gas leaseholds	1,241,724	1,209,724
	5,147,939	5,115,939
Less accumulated depletion	(195,371)	(100,062)
Less impairment	(2,427,968)	-
Net oil and gas properties	2,524,600	5,015,877
Undeveloped oil and gas leaseholds	$ 2,932,730	$ 2,932,730

Total depletion of oil and gas properties amounted to $88,287 and $34,475 for the years ended October 31, 2015 and 2014 respectively. Impairment of $2,427,968 was recorded during the period ending October 31, 2015.

3. Participation Agreement

In connection with the convertible promissory note described in note 5, the Company entered into a participation agreement with a nonaffiliated company whereby the nonaffiliated company would advance up to $350,000 to conduct additional development of the underlying leases at the Garcia Field and drill and complete three additional wells on the acreage. As of October 31, 2015, $248,895 was due on the note. In consideration for extending this credit arrangement, the lender was assigned a 1% overriding royalty interest in the 4,600 acre field and a 20% modified net profits interest in the existing four producing wells in the Garcia Field and a 20% modified net profits interest in three additional wells to be drilled on said acreage. The Company valued the net profits interest and the overriding royalty interest at $136,599 using 10% present value over the estimated life of the wells. The amount was recorded as a debt discount and is being amortized using the effective interest rate method over the life of the promissory note (3 years). Additionally, the lender has the right, at any point during the period of the note, to convert the remaining principal balance on the note to a working interest (see note 5).

The modified net profits interest is based on the gross proceeds from the sale of oil, gas and other minerals in the 4 producing wells in the Garcia Field and 3 additional wells to be drilled. The 20% is applied to 100% of the Company's net revenue interest in the wells which cannot be less than 80% and is reduced by any of the following expenditures:

- any overriding royalties or other burden on production in excess of the 80% net revenue interest;
- production, severance and similar taxes assessed by any taxing authority based on volume or value of the production;
- direct costs incurred in lifting oil or natural gas, or the operating or producing such wells excluding administrative, supervisory or other indirect costs;
- costs reasonably incurred to process the production for market;
- costs reasonably incurred in transportation, delivery, storage or marketing the production.

4. Notes Payable - Affiliates

Notes Payable Affiliates —In December 2010, the Company entered into a purchase and sale agreement to acquire certain oil and gas assets located in Adams, County, Broomfield, County, Huerfano County, Las Animas County, Morgan County and Weld County, Colorado. The Company issued 2,500,000 shares of its $0.0001 par value Common Stock and a promissory note for $360,000 bearing interest at 10% with an original maturity date of March 1, 2011. The shares were valued at $1 per share based on sales of the Company's common stock to third-parties. The promissory note is collateralized by the property and equipment transferred and was subsequently subrogated to a convertible promissory note on January 12, 2012 (See Note 5). In December 2015, the maturity date of the note was extended to December 11, 2016. The balance on the note is $107,070 at October 31, 2015 and 2014, with interest accrued in the amount of $15,286 and $4,579, respectively.

5. Long-term Debt and Note Payable

Convertible Promissory Note —On January 12, 2012 the Company entered into a convertible promissory note bearing interest at 10%, due January 11, 2014, which was extended to July 17, 2016. The Company issued common stock fair valued at $22,500 to extend the note. The note is collateralized by a first priority deed of trust covering approximately 4,600 acres of oil and gas leasehold interests in the Garcia Field, together with the existing wells and equipment in the field. The balance at October 31, 2015 and 2014 was $248,895. The lender has the right to convert the principal to a working interest to a 10% working interest in the collateral as well as a 10% interest in all wells owned by the Company in the Garcia Field in which the lender does not have the 20% modified net profits interest described in Note 3. In the event the principal is less than $350,000, the conversion percentage shall be reduced proportionately. The Company has the right to prepay the note without penalties or fees after giving the lender ten days' notice of its intent. If lender does elect to convert within 10 days after receiving said notice, the conversion rights terminate. The Company recorded a discount to the debt of $136,599 and recognized accretion of the discount in the amounts of $0 and $19,516 for the years ended October 31, 2015 and 2014 respectively. The Company reviewed the conversion feature for beneficial conversion features and embedded derivatives and determined that neither applied.

On October 14, 2014 the Company acquired approximately 98% of the outstanding shares of BIYA Operators, Inc. ("BIYA") an independent oil and gas company. The Company issued a promissory note in the principal amount of $1,860,000 (subject to adjustment for unknown liabilities). The note will be effective when certain leases covering Indian tribal lands have been issued. The note will bear interest at 5% a year and will be payable in October 2016.

In May 2012 BIYA entered into a settlement agreement with a previous partner for amount of $1.2 million. The amount is non-interest bearing and has a minimum monthly payment of $10,000, plus one third of BIYA's net profits, as defined in the agreement, which amounted to approximately $7,000 at October 31, 2014, until paid in full. On April 1, 2015, the agreement was amended, where the balance due will bear interest at 6% a year and has a fixed monthly payment of $5,500 until paid in full. The balance due was $489,154 at October 31, 2015.

Secured Notes —In March, April, June, July and October 2015, the Company issued secured notes in the principal amounts of $250,000, $400,000, $200,000, $350,000 and $50,000 respectively, bearing interest at 12% payable quarterly beginning June 1, 2015 with a two year maturity date. The notes are collateralized by a first priority deed of trust on certain producing wells and their spacing units located in the Horseshoe Gallup Field. The notes and any interest outstanding may be converted, one time only, for new securities offered by the Company. The notes guarantees one year of interest which would be due even upon prepayment of the notes during the first year. The lenders received two year warrants which entitles the holders to purchase up to 360,000 shares of the Company's common stock at a price of $0.80 and $1.50 per common share, valued at approximately $126,000 at October 31, 2015, using the Black Scholes method. The value of the warrants has been recorded as discount on the note and a credit to additional paid in capital. The secured notes had accrued interest payable of approximately $34,500 at October 31, 2015.

Installment Loans — On July 4, 2013, the Company entered into an installment loan bearing interest of 5.39%. The loan is payable in monthly installments of $464 over 48 months commencing August 4, 2013. The loan is collateralized by a vehicle. On July 5, 2015, the Company entered into installment loans bearing interest of 3.62%. The loans are payable in monthly installments of $2,118 over 48 months. The loans are collateralized by two vehicles.

The following summarizes the notes payable:

	2015	2014
Convertible promissory note	$ 248,895	$ 248,895
BIYA note	1,860,000	1,860,000
BIYA settlement	489,154	546,144
Convertible promissory notes	1,250,000	-
Discount convertible promissory notes	(126,000)	-
Installment loan	95,691	13,750
	3,817,740	2,668,789
Current portion	(319,632)	(373,846)
	$ 3,498,108	$ 2,294,943

The above debt matures as follows:

	Year ended October 31
2016	$ 319,632
2017	$ 3,498,108

6. Asset Retirement Obligation

The following table reflects a reconciliation of the Company's asset retirement obligation liability:

	2015	2014
Beginning asset retirement obligation	$ 290,312	$ 222,375
Liabilities incurred	-	43,883
Liabilities settled	-	-
Accretion expense	30,789	24,054
Revision to estimated cash flows	-	-
Ending asset retirement obligation	$ 321,101	$ 290,312

7. Income Taxes

ASC 740 guidance requires that the Company evaluate all monetary tax positions taken, and recognize a liability for any uncertain tax positions that are not more likely than not to be sustained by the tax authorities. The Company has not recorded any liabilities, or interest and penalties, as of October 31, 2015 related to uncertain tax positions. Deferred tax assets and liabilities are recorded based on the differences between the tax bases of assets and liabilities and their carrying amounts for financial reporting purposes, referred to as temporary differences. Deferred tax assets and liabilities at the end of each period are determined using the currently-enacted tax rates applied to taxable income in the periods in which the deferred tax assets and liabilities are expected to be settled or realized. The provision for income taxes differs from the amount computed by applying the statutory federal income tax rate to income before provision for income taxes. The Company's estimated effective tax rate of 39% is offset by a valuation allowance due to the uncertainty regarding the realization of the deferred tax asset.

The tax effects of temporary differences that gave rise to the deferred tax liabilities and deferred tax assets as of October 31, 2015 and 2014 were:

	2015	2014
Deferred tax assets:		
Net operating loss carry forwards	$ 2,270,721	$ 1,422,844
Deferred tax liability:		-
Property and equipment, geologic and geophysical	(31,302)	(41,945)
	2,239,419	1,380,899
Less valuation allowance	(2,239,419)	(1,380,899)
	$ -	$ -

In assessing the realizability of the deferred tax assets, management considers whether it is more likely than not that some or all of the deferred tax assets will not be realized. The ultimate realization of the deferred tax assets is dependent upon the generation of future taxable income during the periods in which the use of such net operating losses are allowed. Among other items, management considers the scheduled reversal of deferred tax liabilities, tax planning strategies and projected future taxable income. At October 31, 2015, the Company had a net operating loss carry forward for regular income tax reporting purposes of approximately $6 million, which will begin expiring in 2030.

Absent the bargain purchase gain that was recognized at the time of acquisition (see Note 11), the Company would have a loss for both financial statement and tax reporting purposes. Accordingly no provision and/or benefit for income taxes has been recorded in the accompanying statement of operations.

The following table shows the reconciliation of the Company's effective tax rate to the expected federal tax rate for the years ended October 31, 2015 and 2014:

Statutory U.S. federal rate	34%
State income taxes	5%
	39%
Net operating loss	(39%)
	-%

The Company files income tax returns in the U.S. and Colorado jurisdictions. There are currently no federal or state income tax examinations underway for these jurisdictions. Income tax returns since inception are subject to audit by taxing authorities as a result of the net operating loss carryforward.

8. Stockholder's Equity

Common Stock —The Company has 450,000,000 shares of $0.0001 par value common stock authorized.

2014

The Company issued 4,474,089 shares of common stock for cash of $2,929,646.

The Company issued 900,000 shares of common stock with a fair value of $900,000 for the acquisition of BIYA.

Included in the shares issued, the Company issued 2,641,052 shares for $2,326,052 to various partners associated with Palo Petroleum, Inc. ("Palo"), 663,720 of these shares with value of $663,720 were issued in December 2014. On January 29, 2015, the Company entered into a participation agreement with Palo, where Palo acquired right to participate in all future operations in the Horseshoe Gallup Field which are not related to the Existing Wells or Existing Production, including the drilling of any future wells. Palo shall have the right to participate in such future operations as a 40.00% of 8/8 Working Interest owner on a heads-up or non-promoted basis. The Company does not have sufficient information to calculate the value of participation in the future working interest and the future participation cost will be charged to operations earned by Palo.

In addition, the Company and Palo entered into an Area of Mutual Interest Agreement ("AMI") covering of all lands in San Juan County, New Mexico outside the Horseshoe Gallup Field. Under this agreement, Palo and the Company shall each be entitled to participate for up to 50% in any leasehold or fee mineral interest within the AMI which is acquired by either Palo or the Company.

2015

The Company issued 50,000 shares to National Petroleum Corporation with a fair value of $22,500, which was treated as lease expense, to extend the convertible promissory note for additional one year (see Note 5). The Company also issued 663,720 shares for cash of $663,720.

The Company issued 280,000 shares of preferred stock for cash of $280,000 and, as per the payment option under secured note agreement. The preferred stock holders received three year warrants which entitles the stockholders to purchase up to 75,250 shares of the Company's common stock at a price of $1.50 per common share. The Company also issued 21,000 shares of preferred stock to pay $21,000 in accrued interest.

9. Commitments and Contingent Liabilities

Legal

We may be subject to legal proceedings, claims and liabilities which arise in the ordinary course of business. We accrue for losses associated with legal claims when such losses are probable and can be reasonably estimated. These accruals are adjusted as additional information becomes available or circumstances change. The Company was not a party to any material legal proceedings as of October 31, 2015.

Environmental

We accrue for losses associated with environmental remediation obligations when such losses are probable and can be reasonably estimated. These accruals are adjusted as additional information becomes available or circumstances change. Costs of future expenditures for environmental remediation obligations are not discounted to their present value. Recoveries of environmental remediation costs from other parties are recorded at their undiscounted value as assets when their receipt is deemed probable. The Company was unaware of any material environmental issues as of October 31, 2015.

Employment Agreements

The Company has a written employment agreement with its president, effective January 1, 2015. Pursuant to his employment agreement, the President will devote such time as each deems necessary to perform his duties to the Company and are subject to conflicts of interest. The employment agreement is an "at will agreement;" however, in the event of termination by the Company, the agreement provides for severance pay equal to four months of base salary in effect at the time of termination. There is also a provision providing for twelve months of base pay in the event of a change in control of the Company. The agreement provides for a two year non-compete in the event of termination. Pursuant to the employment agreements, effective July 1, 2015, the president will receive a base salary of $234,000 per year. If the Company receives cumulative financing, equity or debt of $4 million, the salary will be increased to $280,000. In addition, if the Company sustains production thresholds of 1,000 BOE/day, 1,500 BOE/day and 2,000 BOE/day, the President's salary will be increased to $300,000, $325,500 and $360,000 per year, respectively.

The Company has a written "at will" employment agreement with its Operations Manager (also a principal shareholder) which provides for annual compensation of $66,000 and provides that when the Company achieves three consecutive months of positive cash flows, and to the extent that the Company would still have positive cash flow in the event the compensation was increased by 50%, then there will be a permanent increase in compensation equal to the current compensation multiplied by 150%. In the event of termination by the Company, the agreement provides for severance pay equal to four months of base salary in effect at the time of termination. There is also a provision providing for twelve months of base pay in the event of a change in control of the Company. The agreement provides for a two year non-compete in the event of termination. The Operations Manager may be granted royalties pursuant to the royalty program.

10. Related Parties

The Company has a lease for office space in Littleton, Colorado, with Spotswood Properties, LLC, a Colorado limited liability company ("Spotswood"), and an affiliate of the Company's president. The Company is currently leasing the office space on a month to month basis under the same terms and conditions as the lease that expired July 31, 2013. The lease provides for the payment of $2,667 per month plus utilities and other incidentals. The president of the Company owns 50% of Spotswood. The Company is of the opinion that the terms of the lease are no less favorable than could be obtained from an unaffiliated party. Spotswood was paid $29,000 and $26,000 in fiscal years 2015 and 2014, respectively.

The Company paid $73,299 and $60,642, in fiscal years 2015 and 2014 respectively, to the President's brother for land-man fees and expense reimbursements in connection with performing contract land services for the Company.

The Company paid $201,110 and $178,650 to a director for financial public relations consulting in fiscal years 2015 and 2014, respectively.

The Company paid $77,465 to companies owned by President of BIYA Operators Inc., the Company's wholly owned subsidiary and by his son in fiscal year 2015.

11. Acquisition

On October 14, 2014 the Company acquired approximately 98% of the outstanding shares of BIYA Operators, Inc. ("BIYA") an independent oil and gas company, for cash of $174,000, 900,000 restricted shares of common stock having a value of $900,000, a promissory note in the principal amount of $1,860,000 (subject to adjustment for unknown liabilities) and the assumption of liabilities of BIYA oil and gas company in the approximate amount of $2,000,000. The note will be effective when certain leases covering Indian tribal lands have been issued. The note will bear interest at 5% a year and will be payable in October 2016. The Company did not incur material costs in acquiring BIYA. The transaction was effective October 1, 2014 and was accounted for as a business combination.

BIYA was incorporated under the laws of New Mexico during on September 2011 to pursue mineral extraction. BIYA conducts operations in the United States primarily in the Horseshoe Gallop field in San Juan County, New Mexico.

BIYA's has oil and gas leases covering approximately 10,100 acres and 48 producing wells. The majority of the leased acreage and producing wells are on Mountain Ute tribal land and are leased under an operating agreement with the tribe. Under the agreement, BIYA is to drill three wells by April, 2016, two additional wells by April 2017 and April 2018, each. After April 2018, BIYA is required to drill one well per year. Per the agreement, if BIYA drills and completes a well, and establishes production from that well, it will own a lease of that well, plus the applicable well spacing unit acreage surrounding that well, ranging from 40 acres to 320 acres, based on the formation drilled, from the date of filing an application for permit to drill and for as long as hydrocarbons are produced in paying quantities. All leases held by BIYA carry a royalty between 12.5% and 20%.

The Company has included the results of BIYA's operations in its consolidated financial statements beginning on October 1, 2014.

Fair values of the assets acquired and liabilities assumed in acquisition of BIYA are summarized below:

Current assets, including cash and cash equivalents of $98,809	$	242,788
Property, plant and equipment		1,854,900
Oil and gas properties		5,244,755
Bonds and other assets		167,368
Total assets acquired		7,509,811
Current liabilities		(1,624,167)
Long-term liabilities		(367,460)
Net assets acquired		5,518,184
Bargain purchase gain		(2,584,184)
Net consideration	$	2,934,000

The consideration consisted of cash of $174,000, the issuance of a note in the amount of $1,860,000, and the issuance of 900,000 common shares with a fair value of $900,000.

The unaudited results of operations had the acquisition been made at November 1, 2013 would have been as follows:

		October 31 2014
Revenues	$	1,583,796
Net income (loss)	$	714,031
Net income (loss) per share	$	0.04

12. Subsequent Events

On February 5, 2016, the Company entered into an Agreement to Exchange Securities with Diversified Energy Services, Inc. ("DESI") a Colorado based company. The Company issued 20,032,710 shares in exchange for all the outstanding shares of DESI and assumed DESI's liabilities at January 31, 2016.

DESI offers a full range of services to the Rocky Mountain energy and construction industries and is dedicated to becoming the "one call, last call" solution to a full range of oil field service needs. DESI offers Crane Service, Well Site Construction, Materials Handling and Disposal, Trucking Services, Equipment Operation, and Rigging to the energy industry in the Denver Julesburg Basin and the Rockies. DESI employs upwards of 140 highly qualified, safety focused professionals and operators.

DESI will operate as a wholly owned subsidiary of Diversified Resources and is not expected to experience any change in management, operations, policies or business practices.

On January 20, 2016, the Company entered into secured note facility of $200,000, bearing interest at 12% payable quarterly beginning January 20, 2016 with a two year maturity date. The notes are collateralized by a first priority deed of trust on certain producing wells and their spacing units located in the Horseshoe Gallup Field. The note and any interest outstanding may be converted, one time only, for new securities offered by the Company. The note guarantees one year of interest which would be due even upon prepayment of note during the first year. The lender received two year warrants which allow the lender to purchase up to 40,000 shares of the Company's common stock at a price of $0.80 per share at any time on or before January 20, 2018.

13. Disclosures about Oil and Gas Producing Activities (Unaudited)

Capitalized costs relating to oil and gas producing activities:

	October 31, 2015	October 31, 2014
Proved oil and gas properties	$ 3,906,215	$ 3,906,215
Proved undeveloped oil and gas leaseholds	1,241,724	1,209,724
	5,147,939	5,115,939
Less accumulated depletion and impairment	(2,623,339)	(100,062)
Net oil and gas properties	2,524,600	5,015,877
Undeveloped oil and gas leasholds	$ 2,932,730	$ 2,932,730

Costs incurred in connection with crude oil and natural gas acquisition, exploration and development are as follows:

	2015	2014
Acquisition of properties:		
Proved	$ -	$ 2,634,245
Proved undeveloped	32,000	3,251,669
Development costs	-	7,833
Exploration costs	16,513	41,802
Total	$ 48,513	$ 5,935,549

14. Results of Operations for Oil and Gas Producing Activities

The results of operations for oil and gas producing activities, excluding capital expenditures and corporate overhead and interest costs, are as follows (all in the United States):

	2015	2014
Operating Revenues	$ 602,980	$ 161,623
Costs & expenses:		
Exploration	16,513	41,802
Lease operating expenses	606,853	290,588
Depletion	88,287	34,475
Total costs & expenses	711,653	366,865
Income (loss) before income taxes	(108,673)	(205,242)
Income tax (expense) benefit	42,569	80,665
Results of operations for oil and gas producing activities	$ (66,104)	$ (124,577)

15. Supplementary Oil and Gas Information (Unaudited)

The following supplemental information regarding the oil and gas activities of the Company is presented pursuant to the disclosure requirements promulgated by the Securities and Exchange Commission ("SEC") and FASB ASC 932, Disclosures About Oil and Gas Producing Activities.

Estimated net quantities of reserves of oil and gas for the years ended October 31, 2015 and 2014:

	Oil (Bbl)	Gas (Mcf)	Gallons NG Liquid
Developed at October 31, 2014	299,856	51,298	-
Proved undeveloped at October 31, 2014	1,432,256	1,257,190	6,890,814
Balance, October 31, 2014	1,732,112	1,308,488	6,890,814
Developed at October 31, 2015	350,000	-	-
Proved undeveloped at October 31, 2015	1,537,400	400,000	-
Balance, October 31, 2015	1,887,400	400,000	-

Notable changes in our reserves are summarized as follows:

Gas and NG liquid reserves decreased due to the impairment of the Garcia field. Oil reserves increased due to an increase in proved undeveloped reserves in DJ field.

16. Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Unaudited)

The following is based on natural gas and oil reserves and production volumes estimated by the Company. It may be useful for certain comparison purposes, but should not be solely relied upon in evaluating the Company or its performance. Further, information contained in the following table should not be considered as representative or realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows be viewed as representative of the current value of the Company.

The Company believes that the following factors should be taken into account in reviewing the following information: (1) future costs and selling prices will likely differ from those required to be used in these calculations; (2) due to future market conditions and governmental regulations, actual rates of production achieved in future years may vary significantly from the rate of production assumed in these calculations; (3) selection of a 10% discount rate, as required under the accounting codification, is arbitrary and may not be reasonable as a measure of the relative risk inherent in realizing future net oil and gas revenues; and (4) future net revenues may be subject to different rates of income taxation.

Under the Standardized Measure, future cash inflows were estimated by applying the 12-month average pricing of oil and gas relating to the Company's proved reserves to the year-end quantities of those reserves. Future cash inflows were reduced by estimated future development and production costs based upon year-end costs in order to arrive at net cash flow before tax. Future income tax expense has been computed by applying year-end statutory rates to future pretax net cash flows and the utilization of net operating loss carry-forwards.

Management does not rely solely upon the following information to make investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable, as well as proved reserves, and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated.

Information with respect to the Company's Standardized Measure is as follows:

	2015	2014
Future cash inflows	$ 75,950,000	$ 158,337,002
Future production costs	(21,832,200)	(36,046,933)
Future development costs	(13,760,000)	(19,189,499)
Future income tax expense	(15,739,542)	(40,209,222)
Future net cash flows	24,618,258	62,891,348
10% annual discount for estimated timing of cash flows	(12,766,202)	(31,944,372)
Standardized measure of discounted future net cash flows	$ 11,852,202	$ 30,946,976

There have been significant fluctuations in the posted prices of oil and natural gas during the last two years. Prices actually received from purchasers of the Company's oil and gas is adjusted from posted prices for location differentials, quality differentials, and BTU content.

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)	NG Liquid
October 31, 2014 (Average)	$ 83.90	$ 4.79	$ 0.99
October 31, 2015 (Average)	$ 40.00	$ 2.35	$ -

Principal changes in the Standardized Measure for the years ended October 31, 2015 and 2014 were as follows:

	2015	2014
Standardized measure, beginning of year	$ 30,946,976	$ 310,014
Purchase of reserves in place	-	24,653,719
Purchase of proved undeveloped reserves	-	118,243,820
Sale and transfers, net of production costs	(3,873)	128,965
Net changes in prices and production costs	(59,601,937)	(31,375,014)
Extensions, discoveries, and improved recovery		-
Changes in estimated future development costs	5,429,499	(15,014,499)
Development costs incurred during the period	-	7,833
Revision of quantity estimates	(7,637,858)	4,307,700
Accretion of discount	19,178,170	(30,953,709)
Net change in income taxes	24,469,680	(39,377,642)
Changes in timing and other	(928,601)	15,790
Standardized measure, end of year	$ 11,852,056	$ 30,946,976

EXHIBIT 31

CERTIFICATIONS

I, Paul Laird, certify that;

1. I have reviewed this annual report on Form 10-K of Diversified Resources, Inc.;

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 the 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(e)) and 15a-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 caused 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 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 a significant role in the registrant's internal control over financial reporting.

February 16, 2016

/s/ Paul Laird
Paul Laird,
Principal Executive Officer

CERTIFICATIONS

I, Paul Laird, certify that;

1. I have reviewed this annual report on Form 10-K of Diversified Resources, Inc.;

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 the 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(e)) and 15a-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 caused 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 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 a significant role in the registrant's internal control over financial reporting.

February 16, 2016	*/s/ Paul Laird*
	Paul Laird, Principal Financial Officer

EXHIBIT 32

In connection with the annual report of Diversified Resources, Inc., (the "Company") on Form 10-K for the year ended October 31, 2015, as filed with the Securities Exchange Commission (the "Report") Paul Laird, the Principal Executive and Financial Officer of the Company, certifies pursuant to 18 U.S.C. Sec. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of his 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 operation of the company.

February 16, 2016

/s/ Paul Laird

Paul Laird, Principal Executive and Financial Officer

Exhibit 99.1

Evaluation of the Oil & Gas Reserves
Of the
Horseshoe Gallup Unit,
San Juan County, New Mexico
Constant Prices and Costs

Effective November 1, 2015

Prepared for

Diversified Resources

January 2016

MHA Petroleum Consultants LLC

January 26, 2016

Mr. Jubal Terry
Vice President Exploration
Diversified Resources, Inc.
1789 West Littleton Blvd
Littleton, CO 80120

Dear Mr. Terry:

At your request, MHA Petroleum Consultants, Inc. (MHA) has prepared an estimate of the reserves and income attributable to certain leasehold interests of Diversified Resources, Inc. in the Horseshoe Gallup Unit (HGU) as of November 1, 2015. The results of this study are summarized below:

Diversified Resources - Proved Reserves
Estimated Net Reserve and Income Data
Constant Price and Costs
As of November 1, 2015

Reserves			Income Data				
Reserve Category	Net Remaining Reserves Oil MBbls	Net Remaining Reserves Gas MMcf	Future Net Income M$	Direct Operating Expense M$	Equity Investment M$	Undiscounted Net Cash Flow M$	Discounted Net Cash Flow @ 10% M$
PDP	144	0	5,761	2,828	0	2,296	1,675
PNP	206	0	8,237	4,322	260	2,976	1,302
PUD	1,385	0	55,465	6,292	11,688	32,914	15,094
Total Proved	1,734	0	69,463	13,442	12,110	38,186	18,071

The future net revenue was based on net hydrocarbon volume sold multiplied by anticipated price. Expenses include severance and ad valorem taxes, and the normal cost of operating the wells. Future net cash flow is future net revenue minus expenses and any development costs. The future net cash flow has not been adjusted for outstanding loans, which may exist, nor does it include any adjustments for cash on hand or undistributed income. No attempt has been made to quantify or otherwise account for any accumulated gas production imbalances that may exist.

Reserve Estimates

Reserves reported herein conform to the definitions of the Petroleum Resources Management System (PRMS), a consortium of the SPE, SPEE, AAPG, and WPC. A copy of these definitions is attached to this letter.

The Horseshoe Gallup Unit is located on the Four Corners platform on the edge of central San Juan Basin in northwestern New Mexico in T31N R15-16W, San Juan County, New Mexico (Figure 1). Oil production is from the Gallup Sandstone which is Upper Cretaceous in age. The sands have been described as marine strike-valley sandstones by McCubbin (AAPG V53, #10 Oct 1969, p. 2114-2140). Two separate oil fields, the Horseshoe and Verde fields, have been identified on the subject acreage.

The Horseshoe field, located in the western portion of the acreage, has a northwest-southeast trend which is trapped stratigraphically. The Verde field is located east of the Horseshoe Gallup and trends northeast-southwest. The Verde field produces from a similar interval as Horseshoe Gallup, but is a fractured reservoir associated with the Hogback monocline (Figure 2). Thus the Verde field is associated with the sinuous nature of the Hogback monocline in this area. The Horseshoe Gallup and Verde fields are at a right angle to each other and have separate trapping mechanisms.

Both these shallow fields, discovered in the 1950's and developed through the 1960's, are filled with the same 42 degree API oil with a 100-200 SCF/STB gas-oil ratio. Reservoir drive is a combination of undersaturated oil expansion and gravity drainage. Initial production rates ranged between 75 and 180 BOPD and current production from the 25 active producers averages 2 BOPD per well. Average cumulative oil recovery from these 25 wells is 76,500 stb.

Proved developed producing (PDP) reserves in this report were estimated using decline curve analysis. Following a successful pilot test of an ionizer to reduce paraffin buildup in selected HGU wells, Diversified plans to install ionizers in all PDP's in this field. Quantification of well response to an ionizer was problematic but the uplift in oil rate appears to be at least a factor of two. Per your direction, this study assumed ionizers were installed at a rate of 1 well per week beginning in February 2016. The 28 Proved developed not producing (PNP) wells were assumed to be workedover and ionizers installed per the schedule provided by Diversified. The first workover is slated for April of this year, the final workover in November of 2017. This study used the last reported rate for a well, translated its decline behavior to the scheduled workover date, and increased the rate by a factor of 2 to forecast future production.

Reserves for undeveloped locations were estimated by using a type curve (Figure 3) based on the producing wells and volumetrics. Reservoir productivity across the undrilled locations in the HGU which offset current production is uncertain, consequently these locations were risked by reducing estimated ultimate recovery (EUR) to 75% of the average EUR of producing wells.. Reserves for the resulting 55 PUD's assumed a hyperbolic type curve with an initial production rate (IP) of 52 BOPD and a 50 year cumulative production of 57,791 STB. The type curve IP is approximately 70% of the average IP of the current producing wells. Additional hyperbolic constants included a b value of 1.160, an initial decline rate of 51.74 %/yr, and a terminal decline of 12 %/yr. The PUD's were scheduled to be developed over five years at a rate of 11 wells per year and a completed well cost of $425,000.

Prices, Costs, and Economic Assumptions

This report assumed a constant oil price of $49.06/bbl, the trailing 12 month average price, and applied a differential of $9.00/bbl. Any gas sales were neglected. Effective date of the reserves reported herein is November 1, 2015. Capital cost for a workover and ionizer installation was $6,500 per well. Operating costs, obtained from Diversified Resources, were $800 per well per month prior ionizer installation and $1,000 per well per month after installation. MHA reviewed the operating costs and consider them realistic. Other economic assumptions included a severance tax of 7.09 % and an ad valorem tax of 1.24%. Production from a well was terminated when the well reached its economic limit or production declined to 0.3 BOPD. Salvage value of a well was assumed to be sufficient to cover P&A expenses.

Statement of Risk

The accuracy of reserve and economic evaluations is always subject to uncertainty. The magnitude of this uncertainty is generally proportional to the quantity and quality of data available for analysis. As a well matures and new information becomes available, revisions may be required which may either increase or decrease the previous reserve assignments. Sometimes these revisions may result not only in a significant change to the reserves and value assigned to a property, but also may impact the total company reserve and economic status. The reserves and forecasts contained in this report were based upon a technical analysis of the available data using accepted engineering principles. However, they must be accepted with the understanding that further information and future reservoir performance subsequent to the date of the estimate may justify their revision. It is MHA's opinion that the estimated proved reserves and other reserve information as specified in this report are reasonable, and have been prepared in accordance with generally accepted petroleum engineering and evaluation principles, as set forth in the PRMS manual. Notwithstanding the aforementioned opinion, MHA makes no warranties concerning the data and interpretations of such data. In no event shall MHA be liable for any special or consequential damages arising from Diversified Resources' use of MHA's interpretation, reports, or services produced as a result of its work for Diversified Resources.

It was a pleasure performing this work for Diversified Resource. If you have any questions or wish to discuss something in more detail, please feel free to contact either of the undersigned at 303-277-0270.

Sincerely,

Debra K. Gomez

Debra K. Gomez
Vice President

John P. Seidle

John Seidle
Vice President

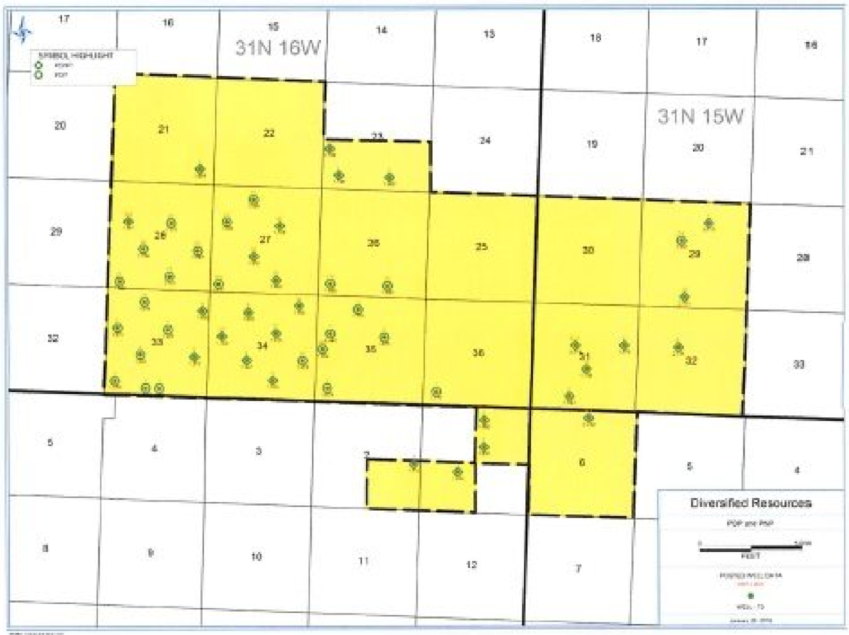

Figure 1: Producing Wells on Acreage Map

Summary Well Economics

RSV_CAT = 1PDP

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R E S E R V E S   A N D   E C O N O M I C S

AS OF DATE: 11/2015

--END-- MO-YEAR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-2015	2.916	0.000	2.195	0.000	40.060	0.000	87.913	0.000	87.913
12-2016	25.384	0.000	19.096	0.000	40.060	0.000	764.969	0.000	764.969
12-2017	29.269	0.000	22.039	0.000	40.060	0.000	882.886	0.000	882.886
12-2018	25.571	0.000	19.261	0.000	40.060	0.000	771.614	0.000	771.614
12-2019	22.365	0.000	16.852	0.000	40.060	0.000	675.093	0.000	675.093
12-2020	19.581	0.000	14.760	0.000	40.060	0.000	591.283	0.000	591.283
12-2021	17.126	0.000	12.915	0.000	40.060	0.000	517.362	0.000	517.362
12-2022	14.287	0.000	10.782	0.000	40.060	0.000	431.914	0.000	431.914
12-2023	10.998	0.000	8.311	0.000	40.060	0.000	332.956	0.000	332.956
12-2024	7.618	0.000	5.774	0.000	40.060	0.000	231.294	0.000	231.294
12-2025	4.709	0.000	3.588	0.000	40.060	0.000	143.738	0.000	143.738
12-2026	3.210	0.000	2.461	0.000	40.060	0.000	98.587	0.000	98.587
12-2027	2.029	0.000	1.572	0.000	40.060	0.000	62.991	0.000	62.991
12-2028	0.940	0.000	0.753	0.000	40.060	0.000	30.180	0.000	30.180
12-2029	0.607	0.000	0.501	0.000	40.060	0.000	20.076	0.000	20.076
S TOT	186.609	0.000	140.860	0.000	40.060	0.000	5642.856	0.000	5642.856
AFTER	3.573	0.000	2.948	0.000	40.060	0.000	118.102	0.000	118.102
TOTAL	190.182	0.000	143.808	0.000	40.060	0.000	5760.958	0.000	5760.958

--END-- MO-YEAR	AD VALOREM TAX -----M$----	PRODUCTION TAX -----M$----	DIRECT OPER EXPENSE -----M$----	INTEREST PAID -----M$----	CAPITAL REPAYMENT -----M$----	EQUITY INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-2015	1.013	6.233	40.000	0.000	0.000	0.000	40.667	40.667	40.346
12-2016	8.813	54.236	271.600	0.000	0.000	162.500	267.819	308.486	288.034
12-2017	10.172	62.597	300.000	0.000	0.000	0.000	510.118	818.604	724.129
12-2018	8.890	54.707	300.000	0.000	0.000	0.000	408.017	1226.621	1041.274
12-2019	7.778	47.864	300.000	0.000	0.000	0.000	319.452	1546.073	1267.050
12-2020	6.812	41.922	300.000	0.000	0.000	0.000	242.549	1788.622	1422.936
12-2021	5.960	36.681	299.000	0.000	0.000	0.000	175.721	1964.343	1525.632
12-2022	4.976	30.623	277.000	0.000	0.000	0.000	119.315	2083.658	1589.091
12-2023	3.836	23.607	230.000	0.000	0.000	0.000	75.513	2159.171	1625.610
12-2024	2.665	16.399	166.000	0.000	0.000	0.000	46.230	2205.402	1645.937
12-2025	1.656	10.191	104.000	0.000	0.000	0.000	27.891	2233.292	1657.083
12-2026	1.136	6.990	73.000	0.000	0.000	0.000	17.461	2250.753	1663.426
12-2027	0.726	4.466	47.000	0.000	0.000	0.000	10.800	2261.553	1666.993
12-2028	0.348	2.140	20.000	0.000	0.000	0.000	7.693	2269.246	1669.298
12-2029	0.231	1.423	12.000	0.000	0.000	0.000	6.421	2275.667	1671.047
S TOT	65.010	400.078	2739.600	0.000	0.000	162.500	2275.667	2275.667	1671.047
AFTER	1.361	8.373	88.000	0.000	0.000	0.000	20.368	2296.035	1675.312
TOTAL	66.371	408.452	2827.600	0.000	0.000	162.500	2296.035	2296.035	1675.312

	OIL	GAS
GROSS WELLS	25.0	0.0
GROSS ULT., MB & MMF	2102.423	43.354
GROSS CUM., MB & MMF	1912.241	43.354
GROSS RES., MB & MMF	190.182	0.000
NET RES., MB & MMF	143.808	0.000
NET REVENUE, M$	5760.958	0.000
INITIAL PRICE, $	40.060	0.000
INITIAL N.I., PCT.	75.000	0.000

LIFE, YRS.	21.50
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	0.00
DISCOUNTED PAYOUT, YRS.	0.00
UNDISCOUNTED NET/INVEST.	15.13
DISCOUNTED NET/INVEST.	11.96
RATE-OF-RETURN, PCT.	100.00
INITIAL W.I., PCT.	100.000

P.W. %	P.W., M$
5.00	1940.734
10.00	1675.312
12.00	1587.272
15.00	1470.382
18.00	1368.685
20.00	1307.983
30.00	1068.267
60.00	685.609
80.00	554.331
100.00	466.766

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R E S E R V E S   A N D   E C O N O M I C S

AS OF DATE: 11/2015

--END-- MO-YEAR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-2015	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2016	9.177	0.000	7.413	0.000	40.060	0.000	296.973	0.000	296.973
12-2017	19.899	0.000	15.922	0.000	40.060	0.000	637.822	0.000	637.822
12-2018	18.656	0.000	14.953	0.000	40.060	0.000	599.001	0.000	599.001
12-2019	16.156	0.000	13.042	0.000	40.060	0.000	522.482	0.000	522.482
12-2020	14.363	0.000	11.665	0.000	40.060	0.000	467.287	0.000	467.287
12-2021	13.288	0.000	10.826	0.000	40.060	0.000	433.691	0.000	433.691
12-2022	12.541	0.000	10.232	0.000	40.060	0.000	409.898	0.000	409.898
12-2023	11.295	0.000	9.241	0.000	40.060	0.000	370.194	0.000	370.194
12-2024	10.356	0.000	8.509	0.000	40.060	0.000	340.853	0.000	340.853
12-2025	9.607	0.000	7.920	0.000	40.060	0.000	317.295	0.000	317.295
12-2026	9.190	0.000	7.582	0.000	40.060	0.000	303.718	0.000	303.718
12-2027	8.859	0.000	7.308	0.000	40.060	0.000	292.771	0.000	292.771
12-2028	8.540	0.000	7.045	0.000	40.060	0.000	282.237	0.000	282.237
12-2029	8.233	0.000	6.792	0.000	40.060	0.000	272.099	0.000	272.099
S TOT	170.160	0.000	138.450	0.000	40.060	0.000	5546.321	0.000	5546.321
AFTER	81.425	0.000	67.176	0.000	40.060	0.000	2691.070	0.000	2691.070
TOTAL	251.585	0.000	205.626	0.000	40.060	0.000	8237.391	0.000	8237.391

--END-- MO-YEAR	AD VALOREM TAX -----M$----	PRODUCTION TAX -----M$----	DIRECT OPER EXPENSE -----M$----	INTEREST PAID -----M$----	CAPITAL REPAYMENT -----M$----	EQUITY INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-2015	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2016	3.421	21.055	125.800	0.000	0.000	182.000	-35.303	-35.303	-37.254
12-2017	7.348	45.222	282.200	0.000	0.000	78.000	225.052	189.749	153.002
12-2018	6.901	42.469	280.200	0.000	0.000	0.000	269.431	459.179	362.304
12-2019	6.019	37.044	246.200	0.000	0.000	0.000	233.219	692.398	526.974
12-2020	5.384	33.131	221.200	0.000	0.000	0.000	207.573	899.971	660.173
12-2021	4.996	30.749	209.200	0.000	0.000	0.000	188.745	1088.717	770.276
12-2022	4.722	29.062	204.200	0.000	0.000	0.000	171.914	1260.631	861.445
12-2023	4.265	26.247	183.200	0.000	0.000	0.000	156.483	1417.114	936.884
12-2024	3.927	24.166	169.200	0.000	0.000	0.000	143.560	1560.673	999.799
12-2025	3.655	22.496	159.200	0.000	0.000	0.000	131.943	1692.616	1052.364
12-2026	3.499	21.534	157.200	0.000	0.000	0.000	121.485	1814.101	1096.364
12-2027	3.373	20.757	157.200	0.000	0.000	0.000	111.441	1925.542	1133.058
12-2028	3.252	20.011	157.200	0.000	0.000	0.000	101.775	2027.317	1163.524
12-2029	3.135	19.292	157.200	0.000	0.000	0.000	92.472	2119.789	1188.690
S TOT	63.898	393.234	2709.400	0.000	0.000	260.000	2119.789	2119.789	1188.690
AFTER	31.003	190.797	1612.600	0.000	0.000	0.000	856.669	2976.458	1301.527
TOTAL	94.902	584.031	4322.000	0.000	0.000	260.000	2976.458	2976.458	1301.527

	OIL	GAS
GROSS WELLS	28.0	0.0
GROSS ULT., MB & MMF	1193.925	75.460
GROSS CUM., MB & MMF	942.340	75.460
GROSS RES., MB & MMF	251.585	0.000
NET RES., MB & MMF	205.626	0.000
NET REVENUE, M$	8237.392	0.000
INITIAL PRICE, $	40.060	0.000
INITIAL N.I., PCT.	80.777	0.000

LIFE, YRS.	62.17
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	1.32
DISCOUNTED PAYOUT, YRS.	1.36
UNDISCOUNTED NET/INVEST.	12.45
DISCOUNTED NET/INVEST.	6.41
RATE-OF-RETURN, PCT.	100.00
INITIAL W.I., PCT.	100.000

P.W. %	P.W., M$
5.00	1842.415
10.00	1301.526
12.00	1157.222
15.00	986.181
18.00	853.665
20.00	780.870
30.00	531.885
40.00	232.265
80.00	151.408
100.00	103.272

RSV_CAT = 4PUD

DATE : 01/25/2016
TIME : 15:32:22
DBS : MHA
SETTINGS : SETNOV2015
SCENARIO : MHA0116_SEC

R E S E R V E S   A N D   E C O N O M I C S

AS OF DATE: 11/2015

--END-- MO-YEAR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$-----	NET GAS SALES -----M$-----	TOTAL NET SALES -----M$-----
12-2015	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2016	77.405	0.000	34.832	0.000	40.060	0.000	1395.385	0.000	1395.385
12-2017	182.829	0.000	82.273	0.000	40.060	0.000	3295.850	0.000	3295.850
12-2018	251.028	0.000	112.962	0.000	40.060	0.000	4525.275	0.000	4525.275
12-2019	302.960	0.000	136.332	0.000	40.060	0.000	5461.456	0.000	5461.456
12-2020	345.212	0.000	155.345	0.000	40.060	0.000	6223.132	0.000	6223.132
12-2021	302.493	0.000	136.122	0.000	40.060	0.000	5453.033	0.000	5453.033
12-2022	229.757	0.000	103.391	0.000	40.060	0.000	4141.833	0.000	4141.833
12-2023	188.644	0.000	84.890	0.000	40.060	0.000	3400.695	0.000	3400.695
12-2024	160.717	0.000	72.322	0.000	40.060	0.000	2897.238	0.000	2897.238
12-2025	139.625	0.000	62.831	0.000	40.060	0.000	2517.027	0.000	2517.027
12-2026	122.472	0.000	55.112	0.000	40.060	0.000	2207.802	0.000	2207.802
12-2027	107.754	0.000	48.489	0.000	40.060	0.000	1942.473	0.000	1942.473
12-2028	94.823	0.000	42.670	0.000	40.060	0.000	1709.377	0.000	1709.377
12-2029	83.444	0.000	37.550	0.000	40.060	0.000	1504.251	0.000	1504.251
S TOT	2589.162	0.000	1165.123	0.000	40.060	0.000	46674.828	0.000	46674.828
AFTER	487.588	0.000	219.415	0.000	40.060	0.000	8789.752	0.000	8789.752
TOTAL	3076.750	0.000	1384.537	0.000	40.060	0.000	55464.578	0.000	55464.578

--END-- MO-YEAR	AD VALOREM TAX -----M$-----	PRODUCTION TAX -----M$-----	DIRECT OPER EXPENSE -----M$-----	INTEREST PAID -----M$-----	CAPITAL REPAYMENT -----M$-----	EQUITY INVESTMENT -----M$-----	FUTURE NET CASHFLOW -----M$-----	CUMULATIVE CASHFLOW -----M$-----	CUM. DISC. CASHFLOW -----M$-----
12-2015	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2016	16.076	98.933	26.000	0.000	0.000	2337.500	-1083.124	-1083.124	-1050.896
12-2017	37.971	233.676	79.200	0.000	0.000	2337.500	607.503	-475.621	-558.745
12-2018	52.135	320.842	132.000	0.000	0.000	2337.500	1682.798	1207.177	725.132
12-2019	62.921	387.217	184.800	0.000	0.000	2337.500	2489.018	3696.195	2462.049
12-2020	71.696	441.220	237.600	0.000	0.000	2337.500	3135.116	6831.312	4455.992
12-2021	62.824	386.620	264.000	0.000	0.000	0.000	4739.589	11570.901	7226.543
12-2022	47.717	293.656	264.000	0.000	0.000	0.000	3536.461	15107.362	9104.144
12-2023	39.179	241.109	264.000	0.000	0.000	0.000	2856.407	17963.768	10482.274
12-2024	33.379	205.414	264.000	0.000	0.000	0.000	2394.445	20358.213	11532.286
12-2025	28.998	178.457	264.000	0.000	0.000	0.000	2045.571	22403.783	12347.680
12-2026	25.436	156.533	264.000	0.000	0.000	0.000	1761.833	24165.617	12986.108
12-2027	22.379	137.721	264.000	0.000	0.000	0.000	1518.373	25683.992	13486.304
12-2028	19.693	121.195	264.000	0.000	0.000	0.000	1304.489	26988.480	13876.985
12-2029	17.330	106.651	264.000	0.000	0.000	0.000	1116.270	28104.750	14180.915
S TOT	537.733	3309.246	3035.600	0.000	0.000	11687.500	28104.750	28104.750	14180.915
AFTER	101.265	623.193	3256.400	0.000	0.000	0.000	4808.894	32913.645	15094.407
TOTAL	638.999	3932.439	6292.000	0.000	0.000	11687.500	32913.645	32913.645	15094.407

	OIL	GAS
GROSS WELLS	55.0	0.0
GROSS ULT., MB & MMF	3076.750	0.000
GROSS CUM., MB & MMF	0.000	0.000
GROSS RES., MB & MMF	3076.750	0.000
NET RES., MB & MMF	1384.537	0.000
NET REVENUE, M$	55464.574	0.000
INITIAL PRICE, $	40.060	0.000
INITIAL W.I., PCT.	45.000	0.000

LIFE, YRS.	28.92
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	2.45
DISCOUNTED PAYOUT, YRS.	2.60
UNDISCOUNTED NET/INVEST.	3.82
DISCOUNTED NET/INVEST.	2.64
RATE-OF-RETURN, PCT.	97.68
INITIAL W.I., PCT.	50.000

P.W. %	P.W., M$
5.00	21695.551
10.00	15094.411
12.00	13208.490
15.00	10922.085
18.00	9125.404
20.00	8134.774
30.00	4786.042
60.00	1153.261
80.00	341.733
100.00	-39.408

Grand Total

DATE : 01/25/2016
TIME : 15:32:22
DBS : MBA
SETTINGS : SEENOV2015
SCENARIO : MBA0116_SEC

R E S E R V E S   A N D   E C O N O M I C S

AS OF DATE: 11/2015

--END-- MO-YEAR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-2015	2.916	0.000	2.195	0.000	40.060	0.000	87.913	0.000	87.913
12-2016	111.967	0.000	61.341	0.000	40.060	0.000	2457.327	0.000	2457.327
12-2017	231.997	0.000	120.234	0.000	40.060	0.000	4816.558	0.000	4816.558
12-2018	295.255	0.000	147.176	0.000	40.060	0.000	5895.890	0.000	5895.890
12-2019	341.480	0.000	166.226	0.000	40.060	0.000	6659.032	0.000	6659.032
12-2020	379.156	0.000	181.770	0.000	40.060	0.000	7281.702	0.000	7281.702
12-2021	332.906	0.000	159.862	0.000	40.060	0.000	6404.085	0.000	6404.085
12-2022	256.585	0.000	124.405	0.000	40.060	0.000	4983.646	0.000	4983.646
12-2023	210.937	0.000	102.442	0.000	40.060	0.000	4103.845	0.000	4103.845
12-2024	178.691	0.000	86.605	0.000	40.060	0.000	3469.385	0.000	3469.385
12-2025	153.941	0.000	74.340	0.000	40.060	0.000	2978.059	0.000	2978.059
12-2026	134.872	0.000	65.155	0.000	40.060	0.000	2610.107	0.000	2610.107
12-2027	118.641	0.000	57.370	0.000	40.060	0.000	2298.236	0.000	2298.236
12-2028	104.303	0.000	50.469	0.000	40.060	0.000	2021.794	0.000	2021.794
12-2029	92.285	0.000	44.843	0.000	40.060	0.000	1796.426	0.000	1796.426
S TOT	2945.931	0.000	1444.433	0.000	40.060	0.000	57864.004	0.000	57864.004
AFTER	572.587	0.000	289.539	0.000	40.060	0.000	11598.925	0.000	11598.925
TOTAL	3518.518	0.000	1733.972	0.000	40.060	0.000	69462.930	0.000	69462.930

--END-- MO-YEAR	AD VALOREM TAX -----M$----	PRODUCTION TAX -----M$----	DIRECT OPER EXPENSE -----M$----	INTEREST PAID -----M$----	CAPITAL REPAYMENT -----M$----	EQUITY INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-2015	1.013	6.233	40.000	0.000	0.000	0.000	40.667	40.667	40.346
12-2016	28.310	174.224	423.400	0.000	0.000	2682.000	-850.608	-809.941	-800.117
12-2017	55.491	341.494	661.400	0.000	0.000	2415.500	1342.673	532.732	318.386
12-2018	67.926	418.019	712.200	0.000	0.000	2337.500	2360.246	2892.978	2128.709
12-2019	76.718	472.125	731.000	0.000	0.000	2337.500	3041.688	5934.666	4256.072
12-2020	83.891	516.273	758.800	0.000	0.000	2337.500	3585.238	9519.904	6539.101
12-2021	73.780	454.050	772.200	0.000	0.000	0.000	5104.056	14623.960	9522.471
12-2022	57.416	353.340	745.200	0.000	0.000	0.000	3827.690	18451.650	11554.681
12-2023	47.280	290.963	677.200	0.000	0.000	0.000	3088.403	21540.053	13044.769
12-2024	39.970	245.979	599.200	0.000	0.000	0.000	2584.235	24124.287	14178.022
12-2025	34.310	211.144	527.200	0.000	0.000	0.000	2205.405	26329.691	15057.127
12-2026	30.071	185.057	494.200	0.000	0.000	0.000	1900.780	28230.473	15745.899
12-2027	26.478	162.945	468.200	0.000	0.000	0.000	1640.613	29871.086	16286.356
12-2028	23.293	143.345	441.200	0.000	0.000	0.000	1413.956	31285.043	16709.909
12-2029	20.696	127.367	433.200	0.000	0.000	0.000	1215.163	32500.203	17040.652
S TOT	666.642	4102.558	8484.600	0.000	0.000	12110.000	32500.203	32500.203	17040.652
AFTER	133.629	822.364	4957.000	0.000	0.000	0.000	5685.930	38186.133	18071.244
TOTAL	800.271	4924.921	13441.600	0.000	0.000	12110.000	38186.137	38186.133	18071.244

	OIL	GAS
GROSS WELLS	108.0	0.0
GROSS ULT., MB & MMF	6373.099	118.814
GROSS CUM., MB & MMF	2854.581	118.814
GROSS RES., MB & MMF	3518.518	0.000
NET RES., MB & MMF	1733.972	0.000
NET REVENUE, M$	69462.961	0.000
INITIAL PRICE, $	40.060	0.000
INITIAL W.I., PCT.	75.000	0.000

LIFE, YRS.	62.17
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	0.00
DISCOUNTED PAYOUT, YRS.	0.00
UNDISCOUNTED NET/INVEST.	4.15
DISCOUNTED NET/INVEST.	2.88
RATE-OF-RETURN, PCT.	100.00
INITIAL W.I., PCT.	51.953

P.W. %	P.W., M$
5.00	25478.699
10.00	18071.250
12.00	15952.984
15.00	13378.647
18.00	11347.754
20.00	10223.627
30.00	6386.195
40.00	3071.135
80.00	1067.473
100.00	530.630

Evaluation of the Oil & Gas Reserves

Of the

Timm Lease,

Weld County, Colorado

Constant Prices and Costs

Effective November 1, 2015

Prepared for

Diversified Resources

January 2016

MHA Petroleum Consultants LLC

January 29, 2016

Mr. Jubal Terry
Vice President Exploration
Diversified Resources, Inc.
1789 West Littleton Blvd
Littleton, CO 80120

Dear Mr. Terry:

At your request, MHA Petroleum Consultants, Inc. (MHA) has prepared an estimate of the reserves and income attributable to certain leasehold interests of Diversified Resources, Inc. in the Timm lease, located in the DJ Basin in Weld County, Colorado, as of November 1, 2015. The results of this study are summarized below:

Diversified Resources Proved, Probable, and Possible Reserves Estimated Net Reserve and Income Data Constant SEC Price and Costs As of November 1, 2015							
Reserves			**Income Data**				
Reserve Category	Net Remaining Reserves Oil MBbls	Gas MMcf	Future Net Income M$	Direct Operating Expense M$	Equity Investment M$	Undiscounted Net Cash Flow M$	Discounted Net Cash Flow @ 10% M$
PUD	152.4	0.4	6,487.1	2,665.4	1,650.0	2,171.7	1,358.4
Total Proved	**152.4**	**0.4**	**6,487.1**	**2,665.4**	**1,650.0**	**2,171.7**	**1,358.4**
PROB	152.4	0.4	6,487.1	2,665.4	1,650.0	2,717.7	1,344.1
POSS	1,472.3	1.8	62,656.4	17,652.7	27,500	17,503.7	8,266.2
Grand Total	**1,777.1**	**2.6**	**75,630.6**	**22,983.6**	**30,800**	**21,847.1**	**10,968.7**

The future net revenue was based on net hydrocarbon volume sold multiplied by anticipated price. Expenses include severance and ad valorem taxes and the normal cost of operating the wells. Future net cash flow is future net revenue minus expenses and any development costs. The future net cash flow has not been adjusted for outstanding loans, which may exist, nor does it include any adjustments for cash on hand or undistributed income. No attempt has been made to quantify or otherwise account for any accumulated gas production imbalances that may exist.

Reserve Estimates

Reserves reported herein conform to the definitions of the Petroleum Resources Management System (PRMS), a consortium of the SPE, SPEE, AAPG, and WPC. A copy of these definitions is attached to this letter.

Effective date of the reserves reported herein is November 1, 2015. Diversified's Working Interest and NRI are 100% and 80%, respectively.

The undrilled Timm lease is located in Section 5 T11N R61W in Weld County, Colorado (Figure 1). Diversified intends to drill and complete three vertical wells in the J sand in July and August of 2016, followed by recompletion in the uphole Codell and Niobrara formations a year later. After 6 months of Codell/Niobrara only production, the J sand will be returned to production. Developed from offset wells to the north and south of the subject acreage, an oil production type curve for these wells (figure 2) has a J sand IP of 80 bpd, an Arps b value of 1.2, and declines to 20 bpd after one year of production. After recompletion in the Codell and Niobrara, the type curve again has an IP of 80 bpd, an Arps b value of 1.3, and an initial decline of 81.5 %/yr. After putting the J sand back on production, the curve increases by 20 bpd for a total of 42 bpd and continues to decline along the same curve as before. Assuming a terminal decline rate of 6 %/yr, a vertical well on this lease will have an estimated ultimate recovery (EUR) of 87,900 MSTB. This is a technical EUR and actual recovery will be less than this due to economics. Gas production was forecast by multiplying oil production by the gas-oil ratio (GOR). Vertical wells in this area, typically completed in multiple formations, show a GOR of about 1,100 scf/stb while horizontal well completed in the Niobrara and Codell exhibit GORs of roughly 800 scf/stb. The J reservoir is a channel sand and offset locations can show very different behaviors and EUR's. Consequently, three locations was classified as proved undeveloped (PUD), three as probable (PROB), and two as possible (POSS).

Current industry practice is to develop the Niobara and Codell in this area with 8 and 4 horizontal wells, respectively, with lateral lengths of 1 or 2 miles. The subject lease has no direct horizontal offsets and use of nearby horizontals to construct a Timm type curve was complicated by differing lateral lengths and vintage effects. Assuming the nominal 640 acre Timm lease is developed with short laterals, a type curve (Figure 3) was developed based on a recent short lateral located approximately 25 miles to the northwest. To account for reservoir risk both the IP and EUR for the type well were risked at 80%. The resulting type curve had an IP of 424 bpd, a b value of 0.85, an initial decline rate of 80.7 %/yr, and a terminal decline rate of 8 %/yr. The resulting EUR was 160 MSTB. This is a technical EUR and actual recovery will be less than this due to economics. Due to the lack of horizontal well production in the immediate area surrounding the subject acreage, all twelve locations were classified as possible. Diversified anticipates drilling one horizontal well in the second quarter of this year, evaluating its performance for a year and a half then drilling the additional 11 wells at a rate of 1 well per month beginning in January of 2018.

Using public domain sources for net thickness, porosity, and water saturation for the Niobara B and C, the Codell, and the J sand and estimating oil formation volume factors with industry standard correlations leads to an original oil in place volume of 26,287 MSTB. Summing the

EUR's for the 15 wells discussed above yields a total recovery of 2,600 MSTB, which implies a recovery factor of 10% of the original oil in place.

Prices, Costs, and Economic Assumptions

This report evaluation a constant oil price of $49.06/bbl, the trailing 12 month average price, and applied a differential of $6.50/bbl. The gas price was a constant $2.765 $/mmbtu with a differential of $0.80/mcf. The gas BTU was 1200 and this study assumed a shrink of 6%. The time lag between drilling and first sales from a well was assumed to be one month. Completed well costs for the vertical and horizontal wells were 550 M$ and 2.2 MM$, respectively. Operating costs for both vertical and horizontal wells were held constant at $3,500/well/month. Severance tax was 5%, ad valorem tax 8%. Salvage value of a well was assumed to be sufficient to cover P&A expenses.

Statement of Risk

The accuracy of reserve and economic evaluations is always subject to uncertainty. The magnitude of this uncertainty is generally proportional to the quantity and quality of data available for analysis. As a well matures and new information becomes available, revisions may be required which may either increase or decrease the previous reserve assignments. Sometimes these revisions may result not only in a significant change to the reserves and value assigned to a property, but also may impact the total company reserve and economic status. The reserves and forecasts contained in this report were based upon a technical analysis of the available data using accepted engineering principles. However, they must be accepted with the understanding that further information and future reservoir performance subsequent to the date of the estimate may justify their revision. It is MHA's opinion that the estimated proved reserves and other reserve information as specified in this report are reasonable, and have been prepared in accordance with generally accepted petroleum engineering and evaluation principles, as set forth in the PRMS manual. Notwithstanding the aforementioned opinion, MHA makes no warranties concerning the data and interpretations of such data. In no event shall MHA be liable for any special or consequential damages arising from Diversified Resources' use of MHA's interpretation, reports, or services produced as a result of its work for Diversified Resources.

It was a pleasure performing this work for Diversified Resources. If you have any questions or wish to discuss something in more detail, please feel free to contact either of the undersigned at 303-277-0270.

Sincerely,

Debra K. Gomez

Debra K. Gomez
Vice President

John P. Seidle

John Seidle
Vice President

Oneline Summary Table

Diversified Resources
Effective November 1, 2015
SEC Pricing
Reserve and Economic Summary

Reserve Category	LEASE	Reservoir	Life Yrs	WI %	NRI %	Start Date	Gross Oil MBBLS	Gross Gas MMCF	Net Oil MBBLS	Net Gas MMCF	Net Revenue M$	Operating Expense and Taxes M$	Net Investment M$	Undisc Net Cashflow M$	Disc @10% Net Cashflow BFIT M$
4PUD	VERT PUD #1		15.2	1.0	0.8	07/2016	63.5	0.2	50.8	0.1	2162.4	888.5	550.0	723.9	454.0
4PUD	VERT PUD #2		15.2	1.0	0.8	07/2016	63.5	0.2	50.8	0.1	2162.4	888.5	550.0	723.9	454.0
4PUD	VERT PUD #3		15.3	1.0	0.8	08/2016	63.5	0.2	50.8	0.1	2162.4	888.5	550.0	723.9	450.4
	TOTAL VERTICAL PROVED						**190.5**	**0.6**	**152.4**	**0.4**	**6,487.1**	**2,665.4**	**1,650.0**	**2,171.7**	**1,358.4**
5PRB	VERT PROB #1		15.3	1.0	0.8	08/2016	63.5	0.2	50.8	0.1	2162.4	888.5	550.0	723.9	450.4
5PRB	VERT PROB #2		15.3	1.0	0.8	09/2016	63.5	0.2	50.8	0.1	2162.4	888.5	550.0	723.9	446.8
5PRB	VERT PROB #3		15.3	1.0	0.8	09/2016	63.5	0.2	50.8	0.1	2162.4	888.5	550.0	723.9	446.8
6POS	VERT POSS #1		15.4	1.0	0.8	10/2016	63.5	0.2	50.8	0.1	2162.4	888.5	550.0	723.9	443.3
6POS	VERT POSS #2		15.4	1.0	0.8	10/2016	63.5	0.2	50.8	0.1	2162.4	888.5	550.0	723.9	443.3
	TOTAL VERTICAL PROBABLE AND POSSIBLE						**317.5**	**1.0**	**254.0**	**0.7**	**10,811.8**	**4,442.3**	**2,750.0**	**3,619.5**	**2,230.7**
	TOTAL VERTICAL ALL CATEGORIES						**508.0**	**1.5**	**406.4**	**1.2**	**17,298.9**	**7,107.7**	**4,400.0**	**5,791.2**	**3,589.0**
6POS	HZ POSS #1	CODELL	17.2	1.0	0.8	04/2016	142.8	0.2	114.2	0.1	4861.0	1323.0	2200.0	1338.0	741.6
6POS	HZ POSS #2	Niobrara C	18.9	1.0	0.8	01/2018	142.8	0.2	114.2	0.1	4861.0	1323.0	2200.0	1338.0	627.7
6POS	HZ POSS #3	Niobrara B	19.0	1.0	0.8	02/2018	142.8	0.2	114.2	0.1	4861.0	1323.0	2200.0	1338.0	622.7
6POS	HZ POSS #4	CODELL	19.1	1.0	0.8	03/2018	142.8	0.2	114.2	0.1	4861.0	1323.0	2200.0	1338.0	617.8
6POS	HZ POSS #5	Niobrara C	19.2	1.0	0.8	04/2018	142.8	0.2	114.2	0.1	4861.0	1323.0	2200.0	1338.0	612.9
6POS	HZ POSS #6	Niobrara B	19.3	1.0	0.8	05/2018	142.8	0.2	114.2	0.1	4861.0	1323.0	2200.0	1338.0	608.1
6POS	HZ POSS #7	Codell	19.3	1.0	0.8	06/2018	142.8	0.2	114.2	0.1	4861.0	1323.0	2200.0	1338.0	603.3
6POS	HZ POSS #8	Niobrara C	19.4	1.0	0.8	07/2018	142.8	0.2	114.2	0.1	4861.0	1323.0	2200.0	1338.0	598.5
6POS	HZ POSS #9	Niobrara B	19.5	1.0	0.8	08/2018	142.8	0.2	114.2	0.1	4861.0	1323.0	2200.0	1338.0	593.8
6POS	HZ POSS #10	Codell	19.6	1.0	0.8	09/2018	142.8	0.2	114.2	0.1	4861.0	1323.0	2200.0	1338.0	589.1
6POS	HZ POSS #11	Niobrara C	19.7	1.0	0.8	10/2018	142.8	0.2	114.2	0.1	4861.0	1323.0	2200.0	1338.0	584.4
6POS	HZ POSS #12	Niobrara B	19.8	1.0	0.8	11/2018	142.8	0.2	114.2	0.1	4861.0	1323.0	2200.0	1338.0	579.8
	HORIZONTAL WELL TOTAL						**1,713.1**	**1.9**	**1,370.5**	**1.5**	**58,331.7**	**15,875.8**	**26,400.0**	**16,055.9**	**7,379.6**
	GRAND TOTAL						**2,221.1**	**3.5**	**1,776.9**	**2.6**	**75,630.6**	**22,983.5**	**30,800.0**	**21,847.1**	**10,968.7**