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

FORM 10-K

(Mark One)

☒ Annual report under Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended **December 31, 2014.**

☐ Transition report under Section 13 or 15(d) of the Securities Exchange Act of 1934 (No fee required)
For the transition period from _______ to _______.

Commission file number: **000-53473**

Torchlight Energy Resources, Inc.

(Exact name of registrant in its charter)

Nevada	**74-3237581**
(State or other jurisdiction of incorporation or Organization)	(I.R.S. Employer Identification No.)

5700 W. Plano Parkway, Suite 3600
Plano, Texas 75093

(Address of principal executive offices)

(214) 432-8002

(Registrant's telephone number, including area code)

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

Common Stock ($0.001 Par Value)

(Title of Each Class)

The NASDAQ Stock Market LLC

(Name of each exchange on which registered)

Securities registered pursuant to Section 12(g) of the Exchange Act:
None

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 ☒

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

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

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

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

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

At June 30, 2014, the aggregate market value of shares held by non-affiliates of the registrant (based upon 14,499,475 shares held by non-affiliates on June 30, 2014) was approximately $59,737,837.

At April 7, 2015, there were 23,478,441 shares of the registrant’s common stock outstanding (the only class of common stock).

DOCUMENTS INCORPORATED BY REFERENCE

None.

NOTE ABOUT FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. These statements include, among other things, statements regarding plans, objectives, goals, strategies, future events or performance and underlying assumptions and other statements, which are other than statements of historical facts. Forward-looking statements may appear throughout this report, including without limitation, the following sections: Item 1 “Business,” Item 1A “Risk Factors,” and Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations.” Forward-looking statements generally can be identified by words such as “anticipates,” “believes,” “estimates,” “expects,” “intends,” “plans,” “predicts,” “projects,” “will be,” “will continue,” “will likely result,” and similar expressions. These forward-looking statements are based on current expectations and assumptions that are subject to risks and uncertainties, which could cause our actual results to differ materially from those reflected in the forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, those discussed in this Annual Report on Form 10-K, and in particular, the risks discussed under the caption “Risk Factors” in Item 1A and those discussed in other documents we file with the Securities and Exchange Commission (“SEC”). Important factors that in our view could cause material adverse effects on our financial condition and results of operations include, but are not limited to, risks associated with the company's ability to obtain additional capital in the future to fund planned expansion, the demand for oil and natural gas, general economic factors, competition in the industry and other factors that may cause actual results to be materially different from those described herein as anticipated, believed, estimated or expected. We undertake no obligation to revise or publicly release the results of any revision to any forward-looking statements, except as required by law. Given these risks and uncertainties, readers are cautioned not to place undue reliance on such forward-looking statements.

As used herein, the “Company,” “Torchlight,” “we,” “our,” and similar terms include Torchlight Energy Resources, Inc. and its subsidiaries, unless the context indicates otherwise.

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PART I

ITEM 1. BUSINESS

Corporate History and Background

Torchlight Energy Resources, Inc. was incorporated in October 2007 under the laws of the State of Nevada as Pole Perfect Studios, Inc. ("PPS").

On November 23, 2010, we entered into and closed a Share Exchange Agreement (the "Exchange Agreement") between the major shareholders of PPS and the shareholders of Torchlight Energy, Inc. ("TEI"). As a result of the transactions effected by the Exchange Agreement, at closing TEI became our wholly-owned subsidiary, and the business of TEI became our sole business. TEI is an energy company, incorporated under the laws of the State of Nevada in June 2010. We are engaged in the acquisition, exploration, exploitation, and/or development of oil and natural gas properties in the United States. In addition to TEI, we also operate our business through Torchlight Energy Operating, LLC, a Texas limited liability company and Hudspeth Oil Corporation, a Texas corporation, both wholly-owned subsidiaries.

On December 10, 2010, we effected a 4-for-1 forward split of our shares of common stock outstanding. All owners of record at the close of business on December 10, 2010 (record date) received three additional shares for every one share they owned. All share amounts reflected throughout this report take into account the 4-for-1 forward split.

Effective February 8, 2011, we changed our name to "Torchlight Energy Resources, Inc." In connection with the name change, our ticker symbol changed from "PPFT" to "TRCH."

Business Overview

Our business model is to focus on drilling and working interest programs within the United States that have a short window of payback, a high internal rate of return, and proven and bookable reserves. We have interests in six oil and gas projects, which projects are described in more detail below in the section titled "Current Projects." We anticipate being involved in multiple other oil and gas projects moving forward, pending adequate funding. We anticipate acquiring exploration and development projects both as a non-operating working interest partner, participating in drilling activities primarily on a basis proportionate to the working interest, and acquiring properties we can operate. We intend to spread the risk associated with drilling programs by entering into a variety of programs in different fields with differing economics.

Salient characteristics of the company include our industry relationships, leverage for prospect selection, anticipated diversity, both geologically and geographically, cost control, partnering, and protection of capital exposure. Management believes opportunities exist to identify and pursue relatively low risk projects at very attractive entry prices. These projects may be available from small operators in financial distress, larger companies that need to share costs, and large producers who are consolidating their activities in other areas. Management believes attractive entry prices and tight cost control will result in returns that are superior to those achieved by major companies or small independents. An integral part of this strategy is the partnering of major activities. Such partnering will enable us to acquire the talents of proven industry veterans, as needed, without affecting our long-term fixed overhead costs.

Key Business Attributes

Experienced People. We build on the expertise and experiences of our management team, including John Brda, Willard McAndrew, and Roger Wurtele. We will also receive guidance from outside advisors as well as our Board of Directors and will align with high quality exploration and technical partners.

Project Focus. We are focusing primarily on low risk exploitation projects by pursuing resources where commercial production has already been established but where opportunity for additional and nearby development is indicated.

Lower Cost Structure. We will attempt to maintain the lowest possible cost structure, enabling the greatest margins and providing opportunities for investment that would not be feasible for higher cost competitors for lower-risk, valuable projects.

Limit Capital Risks. Limited capital exposure is planned initially to add value to a project and determine its economic viability. Projects are staged and have options before additional capital is invested. We will limit our exposure in any one project by participating at reduced working interest levels, thereby being able to diversify with limited capital. Management has experience in successfully managing risks of projects, finance, and value.

Project Focus

Generally, we will focus on lower risk exploitation projects (primarily for oil, although gas projects will be considered if the economics are favorable). Projects are first identified, evaluated, and followed by the engagement of third party operating or financial partners. Subject to overall availability of capital, our interest in large capital projects will be limited. Each opportunity will be investigated on a standalone basis for both technical and financial merit. High risk exploration prospects are less favored than low risk exploitation. We will, however, consider high risk-high reward exploration in connection with exploitation opportunities in a project that would reduce the overall project economic risk. We will consider such projects on their individual merits, and we expect them to be a minor part of our overall portfolio.

We will be actively seeking quality new investment opportunities to sustain our growth, and we believe we will have access to many new projects. The sources of these opportunities will vary but all will be evaluated with the same criteria of technical and economic factors. With a focus on development rather than higher risk exploration projects, it is expected that projects will come from the many small producers who find themselves under-funded or over-extended and therefore vulnerable to price volatility. The financial ability to respond quickly to opportunities will ensure a continuous stream of projects and will enable us to negotiate from a stronger position to enhance value.

With emphasis on acquisitions and development strategies, the types of projects in which we will be involved vary from increased production due to simple re-engineering of existing wellbores to step-out drilling, drilling horizontally, and extensions of known fields. Recompletion of existing wellbores in new zones, development of deeper zones and detailing of structure, and stratigraphic traps with three-dimensional seismic and utilization of new technologies will all be part of our anticipated program. Our preferred type of projects are in-fills to existing production with nearly immediate cash flow and/or adjacent or on trend to existing production. We will prefer projects with moderate to low risk, unrecognized upside potential, and geographic diversity.

Business Processes

We believe there are three principal business processes that we must follow to enable our operations to be profitable. Each major business process offers the opportunity for a distinct partner or alliance as we grow. These processes are:

- Investment Evaluation and Review;
- Operations and Field Activities; and
- Administrative and Finance Management.

Investment Evaluation and Review. This process is the key ingredient to our success. Recognition of quality investment opportunities is the fuel that drives our engine. Broadly, this process includes the following activities: prospect acquisition, regional and local geological and geophysical evaluations, data processing, economic analysis, lease acquisition and negotiations, permitting, and field supervision. We expect these evaluation processes to be managed by our management team. Expert or specific technical support will be outsourced as needed. Only if a project is taken to development, and only then, will additional staff be hired. New personnel will have very specific responsibilities. We anticipate attractive investment opportunities to be presented from outside companies and from the large informal community of geoscientists and engineers. Building a network of advisors is key to the pipeline of high quality opportunities.

Operations and Field Activities. This process will begin following management approval of an investment. Well site supervision, construction, drilling, logging, product marketing, and transportation are examples of some activities. The present plan is that we will prefer to be the operator, but when operations are not possible, we will farm-out sufficient interests to third parties that will be responsible for these operating activities. We will provide personnel to monitor these activities and associated costs.

Administrative and Finance Management. This process will coordinate our initial structuring and capitalization, general operations and accounting, reporting, audit, banking and cash management, regulatory agencies reporting and interaction, timely and accurate payment of royalties, taxes, leases rentals, vendor accounts and performance management that includes budgeting and maintenance of financial controls, and interface with legal counsel and tax and other financial and business advisors.

Current Projects

As of December 31, 2014 the Company had interests in six oil and gas projects and one commercial Salt Water Disposal facility: the Marcelina Creek Field Development in Wilson County, Texas, the Coulter Field in Waller County, Texas, the Smokey Hills Prospect in McPherson County, Kansas, the Ring Energy Joint Venture in Southwest Kansas and the Hunton play in partnership with Husky Ventures in Central Oklahoma and the Orogrande Project in Hudspeth County, Texas.

ITEM 1. BUSINESS - *continued*

Marcelina Creek Field Development.

On July 6, 2010, TEI entered into a participation agreement with Bayshore Operating Corporation, LLC ("Bayshore"), which is currently the holder of an oil, gas, and mineral lease covering approximately 1,045 acres in Wilson County, Texas, known as the Marcelina Creek Field Development. The Participation Agreement provides for the drilling of four wells. Three of the obligation wells have been drilled. The first three wells include a horizontal re-entry well known as the Johnson-1-H, a vertical well known as the Johnson #4, and a lateral well known as the Johnson #2-H. These three wells are presently producing a total of approximately 70 BOPD. The remaining well is to be a vertical development well at a location to be determined within the existing lease. Drilling is anticipated for midyear 2015.

The Marcelina Creek Field Development is located over the Austin Chalk, Buda, and Eagle Ford Formations, which formations are well known and established producers in central Texas. Their production is controlled by vertical fracturing of the rock with high productivity in wells which encounter the greatest amount of fractures. With the advent of horizontal drilling technology, numerous opportunities exist in areas and fields that were only drilled vertically.

Coulter Field

In January 2012, we entered into a farm-in agreement, titled the "Coulter Limited Partnership Agreement" (the "Coulter Agreement"), with La Sal Energy, LLC ("La Sal"). La Sal owns a 100% working interest and a 75% net revenue interest in approximately 940 acres of oil, gas, and mineral leases in Waller County, Texas, on which the well known as "John Coulter #1-R" is located. This well is adjacent to the Katy Field, located on its northwestern updip edge, which produces primarily from the Wilcox Sparks formation.

Pursuant to the Coulter Agreement, we acquired a 34% working interest and a 25.5% net revenue interest from La Sal's interest in the John Coulter #1-R for the purchase price of $350,000, which was to be applied to 100% of the costs of a fracture stimulation treatment on the well. Under the agreement, we had options to purchase additional working interests up to a total of 45%. We exercised the first option and purchased an additional 6% for $50,000, bringing our working interest to 40% and our net revenue interest to 30%. Our option to purchase an additional 5% working interest can be exercised by the payment of $50,000 within 30 days of first commercial production from the well. If commercial production is established, the net revenue split will be 80% to us and 20% to La Sal until net revenue totals $437,500, after which the net revenue will be split according to the interests in the well. Expenses above the initial $350,000 will be split according to the working interests in the well. Our total investment in the project, including fracture stimulation, subsequent testing, purchase of additional interests and capitalized interest, amounted to $710,139 as of December 31, 2014.

The Coulter is a non-core, non-producing asset which we will attempt to monetize by sale of the lease. We presently have approximately 940 acres.

Smokey Hills Prospect, McPherson County, Kansas

In April 2013, we entered into an agreement to acquire certain assets of Xtreme Oil & Gas, Inc. of Plano, Texas ("Xtreme"). Included in that agreement were the Smokey Hills Prospect in McPherson County, Kansas, the Cimarron Area Hunton Project in Logan County, Oklahoma, and an interest in a salt water disposal facility in Seminole, Oklahoma. Total consideration for all the properties was $1.6 million.

The Smokey Hills acquisition included approximately 16,000 gross acres and a well, the Hoffman 1-H within the greater Lindsborg Field area. Our working interest is nearly 18%. Wells had been drilled vertically in the 1960's to present at depths of less than 4,000 feet looking for production from Mississippian carbonated fractured reservoirs. The Hoffman well was drilled laterally 4,200 feet and fracking had not been completed at the time of our acquisition of the project. Core analysis and logs indicated good porosity at 14 to 22%. Following our acquisition, the well was hydraulically fractured, but the results were disappointing.

During 2014 a ten well program to evaluate the Prospect was conducted. Based on the economic outcome of the first five wells and the further geological analysis of the acreage, the drilling program was discontinued during the fourth quarter, 2014 and the two producing wells were shut in.

The Smokey Hill prospect is also non-core, and we will attempt to sell the remaining leases as well as the well bores. We presently have approximately 960 acres under lease and four well bores.

The Ring Energy Joint Venture, Southwest Kansas

In October 2013, we entered into a Joint Venture agreement with Ring Energy. The agreement called for us to provide for $6.2 million in drilling capital to, in effect, match Ring Energy's expenditures for leasing. In exchange for this commitment, we would receive a 50% interest in each well bore drilled and the acreage unit it held, until we had spent $6.2 million. At such time, we would then receive a 50% Working Interest in the entire lease block consisting of 17,000 +/- acres. We were to provide $3.1 million in advance of the program commencing, which would cover approximately 5 wells to be drilled and completed. Once the initial five wells are completed, we and Ring would evaluate the program and the drilling activity and determine if another five wells are to be drilled. Should we continue with the program, we would then deposit another $3.1 million with Ring for drilling and completion of the next five wells.

We have made the initial $3.1 million deposit and the first five well drilling program is completed. Drilling operations commenced in March, 2014. Seven wells have been drilled – three are producing, one can be converted to a salt water disposal well, one was not completed, and two were plugged and abandoned. Based upon results from drilling, the participants elected to suspend further drilling and obtain seismic data to guide continuing development. The seismic data is being analyzed at the date of this filing. As of December 31, 2014, the Company had invested approximately $4,500,000 in the Ring Joint Venture. The company believes this project is still considered to be in the testing phase.

Hunton Play, Central Oklahoma

The Xtreme transaction also included the acquisition of three Hunton wells, the Hancock, Robinson and Lenhart. The Hancock and Robinson are producing wells but have small working interests of 1% and .25 of 1%, respectively.

The Lenhart well is a 62% working interest and was being prepared for a fracture stimulation when it was previously damaged, prior to our acquisition, by the service contractor. The well bore at the Hunton level has an irretrievable pipe in the hole and cannot be used to produce from the Hunton. Although Xtreme won the litigation against the contractor, he failed to pay for the replacement of the well bore, and Xtreme was responsible for costs primarily to Baker-Hughes for work done on the well. We took responsibility for those charges and negotiated a settlement of approximately $600,000.

Subsequent to the above, we have identified a shallow sandstone that could potentially be productive. As previously planned, we tested this formation, and although there were hydrocarbons present, they are not in sufficient quantities to be economic. The Lenhart property was sold for $25,000 and buyer's assumption of plugging liability in 2015.

During the second quarter of 2013, Torchlight entered into an agreement with Husky Ventures to participate in the drilling of wells to the Hunton Formation in central Oklahoma. We continued to expand this relationship with Husky Ventures on a monthly basis as we expand our lease acreage in the contracted Areas of Mutual Interest (AMI's).

When Torchlight executed the agreement Husky had already drilled and completed 18 successful wells in the Hunton. We estimated that Husky had spent, or caused to be spent, $125 million in what we considered a Research and Development project. The results of Husky's initial program lead them to develop certain drilling and completions techniques of which we could participate in and take advantage of.

The terms in our agreement with Husky are that we pay our proportionate costs of leases and operating expenses based on our working interest. For leasing and drilling costs (the AFE), we carry Husky for 15% based on our working interest participation. This is to compensate Husky for the initial program mentioned above and, additionally, the project coordination of the geological, leasing, legal and title opinions, survey and permitting, all drilling, frac design, completion and equipping, day to day operations, and accounting and filing all required monthly and annual reporting to all governmental agencies.

Torchlight believes this is an equitable agreement in that we have the benefit of the initial programs results while participating with a proven operator in areas that continue to provide us with outstanding results in a safe investment environment.

Specifically, we were able to negotiate a 15% working interest in approximately 3,700 acres in the Cimarron Area of Logan County in May 2013. Leasing continued monthly which resulted in the total acreage in which the Company has an interest increasing to 5,020 as of December 31, 2014 (Net undeveloped acres = 343). Detail of developed and undeveloped acreage positions at December 31, 2014, Drilling Activity, and Cumulative Well Status are presented in Tables in Item 2 of this filing. Our net cumulative investment through December 31, 2014 in undeveloped acres in the Cimarron AMI was $612,643.

The first well in the Cimarron AMI, the Boeckman #1-H well, was spud and was subsequently completed and fracture stimulated in July, 2013. We acquired a working interest in the Boeckman #1-H well and subsequently sold part of our ownership in the Boeckman well for $990,000. We agreed to a preferential payout to the purchaser equal to 50% of his acquired interest. The agreement was amended in the first quarter of 2014 to include our agreement to advance funds under a note receivable from the purchaser to be repaid from the purchaser's revenue preference subsequent to October, 2014. Revenue payable to the investor based on revenue to December 31, 2014 has been accrued in the accompanying financial statements.

In the third quarter of 2013, we acquired from a third party for stock, a 15.3% working interest in 5011+/- acres in the Chisolm Trail AMI with Husky Ventures Inc. as the operator. Leasing also continued monthly in this AMI increasing the total acreage in which the Company has an interest to 12,927 as of December 31, 2014 (Net undeveloped acres = 1,829). Detail of developed and undeveloped acreage positions at December 31, 2014, Drilling activity, and Cumulative Well Status are presented in Tables in Item 2 of this filing. Our net cumulative investment through December 31, 2014 in undeveloped acres in the Chisholm Trail AMI was $3,293,287.

In the fourth quarter of 2013 we entered into our third Area of Mutual Interest (AMI) with Husky Ventures, the Viking Prospect. This AMI covers four townships in size. We acquired a 25% interest in 3,945 acres in the Viking. We subsequently acquired an additional 5% in May, 2014. Leasing is continuing monthly so that we had an interest in 7.735 total acres in which the Company has an interest as of December 31, 2014. (Net undeveloped acres = 2,266) Husky drilled the first two wells in the AMI in second quarter, 2014. Detail of developed and undeveloped acreage positions at December 31, 2014, Drilling activity, and Cumulative Well Status are presented in Tables in Item 2 of this filing. Our net cumulative investment through December 31, 2014 in undeveloped acres in the Viking AMI was $1,223,202.

In January of 2014, we again elected to continue to expand in the Hunton Play with Husky Ventures. We contracted for a 25% Working Interest in approximately 5,000 acres in the R4 AMI consisting of eight townships in South Central Oklahoma. We subsequently acquired an additional 5% in May, 2014. Leasing is continuing monthly so that the Company had an interest in 11,745 total acres as of December 31, 2014 (Net undeveloped acres = 3,523). Detail of developed and undeveloped acreage positions at December 31, 2014 is presented in the Table in Item 2 of this filing. Our 2014 cumulative investment through December 31 in the R4 AMI was $2,855,209.

In February of 2014, we acquired a 10% Working Interest in a well in the Prairie Grove AMI from a non-consenting third party who elected not to participate in the well.

In July of 2014, we elected to further expand in the Hunton Play with Husky Ventures. We contracted for a 25% Working Interest in the T4 AMI. There is an active ongoing leasing program in this AMI so that the total acres in which the Company has an interest at December 31, 2014 totals 2,325 acres (Net undeveloped acres = 581). Detail of developed and undeveloped acreage positions at December 31, 2014 is presented in the Table in Item 2 of this filing. Our 2014 cumulative investment through December 31 in the T4 AMI was $841,329.

As of December 31, 2014, we are actively producing from twenty three wells including eleven in the Chisholm Trail, ten in Cimarron, one in Viking, and one in Prairie Grove. One well is completing in the Viking at December 31, 2014.

During February, 2015, the Company entered into an agreement with Husky Ventures Inc. to restructure the amounts due under Husky's Joint Interest Billing ("JIB") to the Company. During the fourth quarter, 2014, Husky presented a series of cash calls to the Company for participation in drilling projects in Oklahoma. The Company did not fund the prepayments requested. However, as drilling began, Husky carried the Company's share of development expenses on the JIB account. It was determined in the first quarter, 2015 that the Company would be unable to fund the requested prepayments and an agreement was reached to reverse the development cost charges on the JIB in exchange for Torchlight relinquishing any claims that it might have had for an interest in the fourteen wells covered by the agreement. The adjustments to account for the reversal were made effective December 31, 2014. No development cost, revenue, or operating expenses with respect to those wells have been recorded in the records of the Company as of December 31, 2014 since the Company did not pay for any participation in those wells.

On April 8, 2015, we announced that we are seeking to divest certain of our Hunton assets located in Logan and Kingfisher Counties, Oklahoma. We are actively marketing these assets to potential buyers. These assets include lease rights and current production, which are being marketed separately. We have been in discussions with interested parties and expect to have a buyer identified shortly. The proceeds from a sale of all or a portion of the assets will be used to satisfy obligations to our Series A Note holders.

Salt Water Disposal Facility

As part of the Xtreme transaction we also acquired a 22.5% net royalty on a salt water disposal facility in Seminole, Oklahoma. No value was placed on the facility due to operational uncertainty. The facility which was newly commissioned in January 2013 is a state of the art disposal facility which can handle 20,000 barrels of produced and injected fluids per day. Oil and gas wells produce large quantities of saltwater that must be trucked and disposed of at a cost to the producer. In addition to the royalty, we have a 24.65% Working Interest which was acquired from some investors that have turned over their working interest in lieu of paying their outstanding JIB Account Receivable due to Torchlight, plus the right to an additional working interest of 37.5% when the original investors in the facility receive a payout of their investment. This SWD facility is considered non-core and will be sold for the right offer.

ITEM 1. BUSINESS - *continued*

Orogrande Project, West Texas

On August 7, 2014, we entered into a Purchase Agreement with Hudspeth Oil Corporation ("Hudspeth"), McCabe Petroleum Corporation ("MPC"), and Greg McCabe. Mr. McCabe is the sole owner of both Hudspeth and MPC. Under the terms and conditions of the Purchase Agreement, at closing, we purchased 100% of the capital stock of Hudspeth which holds certain oil and gas assets, including a 100% working interest in 172,000 mostly contiguous acres in the Orogrande Basin in West Texas. This acreage is in the primary term under five-year leases that carry additional five-year extension provisions. As consideration, at closing we issued 868,750 shares of our common stock to Mr. McCabe and paid a total of $100,000 in geologic origination fees to third parties. Additionally, Mr. McCabe will have an optional 10% working interest back-in after payout and a reversionary interest if drilling obligations are not met, all under the terms and conditions of a participation and development agreement. Closing of the transactions contemplated by the Purchase Agreement occurred on September 23, 2014.

Of the 172,000 acres 40,154 were scheduled for renewal in December, 2014. As of December 31, 2014 the Company had not renewed the leases. The Company is in discussions regarding renewal at the date of this filing.

Prior to March 31, 2015, the Company had the obligation to begin drilling its first well in order to hold the acreage block. The well was permitted and spudded by March 31 and drilling is in progress at date of this filing

Project Prospects

We have an ongoing process to identify specific projects that we will consider investing in, pending our ability to obtain adequate funding. We have not yet conducted thorough due diligence on any project prospect, nor had we made any significant commitments on any new projects as of December 31, 2014, beyond the continued involvement and expansion of our current projects with our partners. There is no assurance we will choose to invest in any of these projects, if and when adequate funding becomes available.

Industry and Business Environment

Our industry and its business environment have been altered during the last decade and in particular since Torchlight was founded in early 2010. Population in the US has increased by nearly 40 million people in the last decade. Yet our demand for crude oil has remained relatively constant at slightly less than 20 million barrels per day. When Torchlight was founded in 2010, over one-half of US crude oil daily requirements were imported; with a significant amount from non-North American sources. The industry was also just beginning to see production from shale resource plays make an impact and a "land rush" to acquire mineral leases was exploding. The "Shale Gale" as some in the industry call it was just starting to gain momentum. In particular resource plays in the Bakken formation of North Dakota, the Eagle Ford formation in Texas and the Marcelius of the Eastern U.S. drew industry attention. Acreage costs skyrocketed and huge deals such as the Marathon Oil-Hillcorp acquisition made headlines.

Since then, the industry has steadily increased the number of wells drilled and improved completion techniques, increasing production, and lowered capital requirements. The Bakken formation and the Eagle Ford formation now each produce 1 million barrels of oil per day to add to our domestic supply. With additional secure domestic supply this has allowed the US to significantly reduce its reliance on non-North American crude sources, namely the Middle East.

Currently, we are experiencing a time of lower oil prices caused by lower demand, higher US Supply, and OPEC's policies on production. This has caused oil prices to plummet over the last six months from the highs of $105 plus oil per barrel, to reaching lows of nearly $42 per barrel. Unfortunately, this is the cyclical nature of the oil and gas industry. We experience highs and lows that seem to come in cycles. Fortunately, advances in technology drive the US market and we feel this will drive the prices down on exploration and drilling programs over time.

Competition

The oil and natural gas industry is intensely competitive, and we will compete with numerous other companies engaged in the exploration and production of oil and gas. Some of these companies have substantially greater resources than we have. Not only do they explore for and produce oil and natural gas, but also many carry on midstream and refining operations and market petroleum and other products on a regional, national, or worldwide basis. The operations of other companies may be able to pay more for exploratory prospects and productive oil and natural gas properties. They may also have more resources to define, evaluate, bid for, and purchase a greater number of properties and prospects than our financial or human resources permit.

Our larger or integrated competitors may have the resources to be better able to absorb the burden of current and future federal, state, and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to locate reserves and acquire interests in properties in the future will be dependent upon our ability and resources to evaluate and select suitable properties and consummate transactions in this highly competitive environment. In addition, we may be at a disadvantage in producing oil and natural gas properties and bidding for exploratory prospects because we have fewer financial and human resources than other companies in our industry. Should a larger and better financed company decide to directly compete with us, and be successful in its efforts, our business could be adversely affected.

Marketing and Customers

The market for oil and natural gas that we will produce depends on factors beyond our control, including the extent of domestic production and imports of oil and natural gas, the proximity and capacity of natural gas pipelines and other transportation facilities, demand for oil and natural gas, the marketing of competitive fuels, and the effects of state and federal regulation. The oil and gas industry also competes with other industries in supplying the energy and fuel requirements of industrial, commercial, and individual consumers.

Our oil production is expected to be sold at prices tied to the spot oil markets. Our natural gas production is expected to be sold under short-term contracts and priced based on first of the month index prices or on daily spot market prices. We will rely on our operating partners to market and sell our production.

Governmental Regulation and Environmental Matters

Our operations are subject to various rules, regulations, and limitations impacting the oil and natural gas exploration and production industry as a whole.

<u>Regulation of Oil and Natural Gas Production</u>

Our oil and natural gas exploration, production, and related operations, when developed, will be subject to extensive rules and regulations promulgated by federal, state, tribal, and local authorities and agencies. Certain states may also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from wells, and the regulation of spacing, plugging, and abandonment of such wells. Failure to comply with any such rules and regulations can result in substantial penalties. The regulatory burden on the oil and gas industry will most likely increase our cost of doing business and may affect our profitability. Although we believe we are currently in substantial compliance with all applicable laws and regulations, because such rules and regulations are frequently amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws. Significant expenditures may be required to comply with governmental laws and regulations and may have a material adverse effect on our financial condition and results of operations.

Environmental Matters

Our operations and properties are and will be subject to extensive and changing federal, state, and local laws and regulations relating to environmental protection, including the generation, storage, handling, emission, transportation, and discharge of materials into the environment, and relating to safety and health. The recent trend in environmental legislation and regulation generally is toward stricter standards, and this trend will likely continue. These laws and regulations may:

- require the acquisition of a permit or other authorization before construction or drilling commences and for certain other activities;
- limit or prohibit construction, drilling, and other activities on certain lands lying within wilderness and other protected areas;
- impose substantial liabilities for pollution resulting from operations; or
- restrict certain areas from fracking and other stimulation techniques.

The permits required for our operations may be subject to revocation, modification, and renewal by issuing authorities. Governmental authorities have the power to enforce their regulations, and violations are subject to fines or injunctions, or both. In the opinion of management, we are and will be 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 our company, 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, joint, and several liability on owners and operators of 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 Federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes govern the disposal of "solid waste" and "hazardous waste" and authorize the imposition of substantial fines and penalties for noncompliance. Although CERCLA currently excludes petroleum from its definition of "hazardous substance," state laws affecting our operations may 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.

The Endangered Species Act ("ESA") seeks to ensure that activities do not jeopardize endangered or threatened animal, fish, and plant species, nor destroy or modify the critical habitat of such species. Under ESA, exploration and production operations, as well as actions by federal agencies, may not significantly impair or jeopardize the species or its habitat. ESA provides for criminal penalties for willful violations of the Act. Other statutes that provide protection to animal and plant species and that may apply to our operations include, but are not necessarily limited to, the Fish and Wildlife Coordination Act, the Fishery Conservation and Management Act, the Migratory Bird Treaty Act and the National Historic Preservation Act. Although we believe that our operations will be in substantial compliance with such statutes, any change in these statutes or any reclassification of a species as endangered could subject our company to significant expenses to modify our operations or could force our company to discontinue certain operations altogether.

Climate Change

Significant studies and research have been devoted to climate change and global warming, and climate change has developed into a major political issue in the United States and globally. Certain research suggests that greenhouse gas emissions contribute to climate change and pose a threat to the environment. Recent scientific research and political debate has focused in part on carbon dioxide and methane incidental to oil and natural gas exploration and production. Many states and the federal government have enacted legislation directed at controlling greenhouse gas emissions, and future legislation and regulation could impose additional restrictions or requirements in connection with our drilling and production activities and favor use of alternative energy sources, which could affect operating costs and demand for oil products. As such, our business could be materially adversely affected by domestic and international legislation targeted at controlling climate change.

Employees

We currently have six full time employees and no part time employees. We anticipate adding additional employees, when adequate funds are available, and using independent contractors, consultants, attorneys, and accountants as necessary to complement services rendered by our employees. We presently have independent technical professionals under consulting agreements who are available to us on an as needed basis.

Research and Development

We did not spend any funds on research and development activities during years ended December 31, 2014 and 2013.

ITEM 1A. RISK FACTORS

An investment in us involves a high degree of risk and is suitable only for prospective investors with substantial financial means who have no need for liquidity and can afford the entire loss of their investment in us. Prospective investors should carefully consider the following risk factors, in addition to the other information contained in this report.

Risks Related to the Company and the Industry

We are currently in default on our 12% Series A Secured Convertible Promissory Notes and our 12% Series B Convertible Unsecured Promissory Notes.

On March 31, 2015, the maturity date for our issued and outstanding 12% Series A Secured Convertible Promissory Notes (“Series A Notes”) occurred, and we did not make any payment to these note holders of the principal and interest due thereunder. This is an event of default under the terms and conditions of the Series A Notes, and the Agent for the Series A Note holders may exercise on behalf of such holders all rights and remedies available under the terms and conditions of the Series A Notes or applicable laws. All obligations under the Series A Notes will bear interest at a default rate of 18% per annum until such time that they are paid in full. The total principal amount outstanding on the Series A Notes is $8,117,598, exclusive of interest. We are having ongoing discussions with the Agent regarding various possible solutions for the payment of this obligation, and we are actively marketing certain assets to potential buyers. Proceeds of from a sale of all or a portion of these assets will be used to satisfy these obligations. If we are unable to timely find a buyer for these assets to pay this obligation, or, alternatively, reach a different solution for payment of this obligation with the Series A Note holders, these holders may seek to foreclose on our assets.

Additionally, our default in payment of the Series A Notes triggered a cross-default provision in our 12% Series B Convertible Unsecured Promissory Notes (“Series B Notes”), and any holder of a Series B Note may declare any an all of the obligations under such note due and payable and/or exercise any other rights and remedies available to such holder under the terms and conditions of the Series B Notes. All obligations under the Series B Notes will bear interest at a default rate of 16% per annum. We did not make the interest payment due to Series B Note holders on March 31, 2015. The total principal amount outstanding on the Series B Notes is $4,569,500, exclusive of interest.

We have a limited operating history, and may not be successful in developing profitable business operations.

We have a limited operating history. Our business operations must be considered in light of the risks, expenses and difficulties frequently encountered in establishing a business in the oil and natural gas industries. As of the date of this report, we have generated limited revenues and have limited assets. We have an insufficient history at this time on which to base an assumption that our business operations will prove to be successful in the long-term. Our future operating results will depend on many factors, including:

- our ability to raise adequate working capital;
- the success of our development and exploration;
- the demand for natural gas and oil;
- the level of our competition;
- our ability to attract and maintain key management and employees; and
- our ability to efficiently explore, develop, produce or acquire sufficient quantities of marketable natural gas or oil in a highly competitive and speculative environment while maintaining quality and controlling costs.

To achieve profitable operations in the future, we must, alone or with others, successfully manage the factors stated above, as well as continue to develop ways to enhance our production efforts, when commenced. Despite our best efforts, we may not be successful in our exploration or development efforts, or obtain required regulatory approvals. There is a possibility that some, or all, of the wells in which we obtain interests may never produce oil or natural gas.

We have limited capital and will need to raise additional capital in the future.

We do not currently have sufficient capital to fund both our continuing operations and our planned growth. We will require additional capital to continue to grow our business via acquisitions and to further expand our exploration and development programs. We may be unable to obtain additional capital when required. Future acquisitions and future exploration, development, production and marketing activities, as well as our administrative requirements (such as salaries, insurance expenses and general overhead expenses, as well as legal compliance costs and accounting expenses) will require a substantial amount of additional capital and cash flow.

We may pursue sources of additional capital through various financing transactions or arrangements, including joint venturing of projects, debt financing, equity financing, or other means. We may not be successful in identifying suitable financing transactions in the time period required or at all, and we may not obtain the capital we require by other means. If we do not succeed in raising additional capital, our resources may not be sufficient to fund our planned operations.

Our ability to obtain financing, if and when necessary, may be impaired by such factors as the capital markets (both generally and in the oil and gas industry in particular), our limited operating history, the location of our oil and natural gas properties and prices of oil and natural gas on the commodities markets (which will impact the amount of asset-based financing available to us, if any) and the departure of key employees. Further, if oil or natural gas prices on the commodities markets decline, our future revenues, if any, will likely decrease and such decreased revenues may increase our requirements for capital. If the amount of capital we are able to raise from financing activities, together with our revenues from operations, is not sufficient to satisfy our capital needs (even to the extent that we reduce our operations), we may be required to cease our operations, divest our assets at unattractive prices or obtain financing on unattractive terms.

Any additional capital raised through the sale of equity may dilute the ownership percentage of our stockholders. Raising any such capital could also result in a decrease in the fair market value of our equity securities because our assets would be owned by a larger pool of outstanding equity. The terms of securities we issue in future capital transactions may be more favorable to our new investors, and may include preferences, superior voting rights and the issuance of other derivative securities, and issuances of incentive awards under equity employee incentive plans, which may have a further dilutive effect.

We may incur substantial costs in pursuing future capital financing, including investment banking fees, legal fees, accounting fees, securities law compliance fees, printing and distribution expenses and other costs. We may also be required to recognize non-cash expenses in connection with certain securities we may issue, which may adversely impact our financial condition.

Our auditor has indicated that certain factors raise substantial doubt about our ability to continue as a going concern.

The financial statements included with this report are presented under the assumption that we will continue as a going concern, which contemplates the realization of assets and the satisfaction of liabilities in the normal course of business over a reasonable length of time. We had a net loss of approximately $15.8 million for the year ended December 31, 2014 and an accumulated deficit in aggregate of approximately $31.7 million at year end. We are not generating sufficient operating cash flows to support continuing operations, and expect to incur further losses in the development of our business.

On March 31, 2015, the maturity date for our issued and outstanding 12% Series A Secured Convertible Promissory Notes ("Series A Notes") occurred, and we did not make any payment to these note holders of the principal and interest due thereunder. This is an event of default under the terms and conditions of the Series A Notes, and the Agent for the Series A Note holders may exercise on behalf of such holders all rights and remedies available under the terms and conditions of the Series A Notes or applicable laws.

Additionally, our default in payment of the Series A Notes triggered a cross-default provision in our 12% Series B Convertible Unsecured Promissory Notes ("Series B Notes"), and any holder of a Series B Note may declare any an all of the obligations under such note due and payable and/or exercise any other rights and remedies available to such holder under the terms and conditions of the Series B Notes.

In our financial statements for the year ended December 31, 2014, our auditor indicated that certain factors raised substantial doubt about our ability to continue as a going concern. These factors included our accumulated deficit, as well as the fact that we were not generating sufficient cash flows to meet our regular working capital requirements. Our ability to continue as a going concern is dependent upon our ability to generate future profitable operations and/or to obtain the necessary financing to meet our obligations and repay our liabilities arising from normal business operations when they come due. Management's plan to address our ability to continue as a going concern includes: (1) obtaining debt or equity funding from private placement or institutional sources; (2) obtaining loans from financial institutions, where possible, or (3) participating in joint venture transactions with third parties. Although management believes that it will be able to obtain the necessary funding to allow us to remain a going concern through the methods discussed above, there can be no assurances that such methods will prove successful. The accompanying financial statements do not include any adjustments that might result from the outcome of this uncertainty.

As a non-operator, our development of successful operations relies extensively on third-parties who, if not successful, could have a material adverse effect on our results of operation.

We expect to primarily participate in wells operated by third-parties. As a result, we will not control the timing of the development, exploitation, production and exploration activities relating to leasehold interests we acquire. We do, however, have certain rights as granted in our Joint Operating Agreements that allow us a certain degree of freedom such as, but not limited to, the ability to propose the drilling of wells. If our drilling partners are not successful in such activities relating to our leasehold interests, or are unable or unwilling to perform, our financial condition and results of operation could have an adverse material effect.

Further, financial risks are inherent in any operation where the cost of drilling, equipping, completing and operating wells is shared by more than one person. We could be held liable for the joint activity obligations of the operator or other working interest owners such as nonpayment of costs and liabilities arising from the actions of the working interest owners. In the event the operator or other working interest owners do not pay their share of such costs, we would likely have to pay those costs. In such situations, if we were unable to pay those costs, there could be a material adverse effect to our financial position.

Because of the speculative nature of oil and gas exploration, there is risk that we will not find commercially exploitable oil and gas and that our business will fail.

The search for commercial quantities of oil and natural gas as a business is extremely risky. We cannot provide investors with any assurance that any properties in which we obtain a mineral interest will contain commercially exploitable quantities of oil and/or gas. The exploration expenditures to be made by us may not result in the discovery of commercial quantities of oil and/or gas. Problems such as unusual or unexpected formations or pressures, premature declines of reservoirs, invasion of water into producing formations and other conditions involved in oil and gas exploration often result in unsuccessful exploration efforts. If we are unable to find commercially exploitable quantities of oil and gas, and/or we are unable to commercially extract such quantities, we may be forced to abandon or curtail our business plan, and as a result, any investment in us may become worthless.

Strategic relationships upon which we may rely are subject to change, which may diminish our ability to conduct our operations.

Our ability to successfully acquire oil and gas interests, to build our reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers will depend on developing and maintaining close working relationships with industry participants and our ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment. These realities are subject to change and our inability to maintain close working relationships with industry participants or continue to acquire suitable property may impair our ability to execute our business plan.

To continue to develop our business, we will endeavor to use the business relationships of our management to enter into strategic relationships, which may take the form of joint ventures with other private parties and contractual arrangements with other oil and gas companies, including those that supply equipment and other resources that we will use in our business. We may not be able to establish these strategic relationships, or if established, we may not be able to maintain them. In addition, the dynamics of our relationships with strategic partners may require us to incur expenses or undertake activities we would not otherwise be inclined to in order to fulfill our obligations to these partners or maintain our relationships. If our strategic relationships are not established or maintained, our business prospects may be limited, which could diminish our ability to conduct our operations.

The price of oil and natural gas has historically been volatile. If it were to decrease substantially, our projections, budgets, and revenues would be adversely affected, potentially forcing us to make changes in our operations.

Our future financial condition, results of operations and the carrying value of any oil and natural gas interests we acquire will depend primarily upon the prices paid for oil and natural gas production. Oil and natural gas prices historically have been volatile and likely will continue to be volatile in the future, especially given current world geopolitical conditions. Our cash flows from operations are highly dependent on the prices that we receive for oil and natural gas. This price volatility also affects the amount of our cash flows available for capital expenditures and our ability to borrow money or raise additional capital. The prices for oil and natural gas are subject to a variety of additional factors that are beyond our control. These factors include:

- the level of consumer demand for oil and natural gas;
- the domestic and foreign supply of oil and natural gas;
- the ability of the members of the Organization of Petroleum Exporting Countries ("OPEC") to agree to and maintain oil price and production controls;
- the price of foreign oil and natural gas;
- domestic governmental regulations and taxes;
- the price and availability of alternative fuel sources;
- weather conditions;
- market uncertainty due to political conditions in oil and natural gas producing regions, including the Middle East; and
- worldwide economic conditions.

These factors as well as the volatility of the energy markets generally make it extremely difficult to predict future oil and natural gas price movements with any certainty. Declines in oil and natural gas prices affect our revenues, and could reduce the amount of oil and natural gas that we can produce economically. Accordingly, such declines could have a material adverse effect on our financial condition, results of operations, oil and natural gas reserves and the carrying values of our oil and natural gas properties. If the oil and natural gas industry experiences significant price declines, we may be unable to make planned expenditures, among other things. If this were to happen, we may be forced to abandon or curtail our business operations, which would cause the value of an investment in us to decline in value, or become worthless.

If oil or natural gas prices remain depressed or drilling efforts are unsuccessful, we may be required to record write downs of our oil and natural gas properties.

If oil or natural gas prices remain depressed or drilling efforts are unsuccessful, we could be required to write down the carrying value of certain of our oil and natural gas properties. Write downs may occur when oil and natural gas prices are low, or if we have downward adjustments to our estimated proved reserves, increases in our estimates of operating or development costs, deterioration in drilling results or mechanical problems with wells where the cost to re drill or repair is not supported by the expected economics.

Under the full cost method of accounting, capitalized oil and gas property costs less accumulated depletion and net of deferred income taxes may not exceed an amount equal to the present value, discounted at 10%, of estimated future net revenues from proved oil and gas reserves plus the cost of unproved properties not subject to amortization (without regard to estimates of fair value), or estimated fair value, if lower, of unproved properties that are subject to amortization. Should capitalized costs exceed this ceiling, an impairment would be recognized.

At December 31, 2014, we performed an impairment review using prices that reflect an average of 2014's monthly prices as prescribed pursuant to the SEC's guidelines. These average prices used in the December 31, 2014 impairment review are significantly higher than the actual and currently forecasted prices in 2015. As lower average monthly pricing is reflected in the trailing 12-month average pricing calculation, the present value of our future net revenues would decline and impairment could be recognized. If this significantly lower pricing environment persists we expect we could be required to writedown the value of our oil and gas properties. Given the current oil and natural gas pricing environment, we believe we could have noncash ceiling test write-downs of our oil and natural gas properties in 2015. The quarterly ceiling test considers many factors including reserves, capital expenditure estimates and trailing 12-month average prices.

Because of the inherent dangers involved in oil and gas operations, there is a risk that we may incur liability or damages as we conduct our business operations, which could force us to expend a substantial amount of money in connection with litigation and/or a settlement.

The oil and natural gas business involves a variety of operating hazards and risks such as well blowouts, pipe failures, casing collapse, explosions, uncontrollable flows of oil, natural gas or well fluids, fires, spills, pollution, releases of toxic gas and other environmental hazards and risks. These hazards and risks could result in substantial losses to us from, among other things, injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, cleanup responsibilities, regulatory investigation and penalties and suspension of operations. In addition, we may be liable for environmental damages caused by previous owners of property purchased and leased by us. In recent years, there has also been increased scrutiny on the environmental risk associated with hydraulic fracturing, such as underground migration and surface spillage or mishandling of fracturing fluids including chemical additives. As a result, substantial liabilities to third parties or governmental entities may be incurred, the payment of which could reduce or eliminate the funds available for exploration, development or acquisitions or result in the loss of our properties and/or force us to expend substantial monies in connection with litigation or settlements. We currently have no insurance to cover such losses and liabilities, and even if insurance is obtained, there can be no assurance that it will be adequate to cover any losses or liabilities. We cannot predict the availability of insurance or the availability of insurance at premium levels that justify our purchase. The occurrence of a significant event not fully insured or indemnified against could materially and adversely affect our financial condition and operations. We may elect to self-insure if management believes that the cost of insurance, although available, is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event not fully covered by insurance could have a material adverse effect on our financial condition and results of operations, which could lead to any investment in us becoming worthless.

The market for oil and gas is intensely competitive, and competition pressures could force us to abandon or curtail our business plan.

The market for oil and gas exploration services is highly competitive, and we only expect competition to intensify in the future. Numerous well-established companies are focusing significant resources on exploration and are currently competing with us for oil and gas opportunities. Other oil and gas companies may seek to acquire oil and gas leases and properties that we have targeted. Additionally, other companies engaged in our line of business may compete with us from time to time in obtaining capital from investors. Competitors include larger companies which, in particular, may have access to greater resources, may be more successful in the recruitment and retention of qualified employees and may conduct their own refining and petroleum marketing operations, which may give them a competitive advantage. Actual or potential competitors may be strengthened through the acquisition of additional assets and interests. Additionally, there are numerous companies focusing their resources on creating fuels and/or materials which serve the same purpose as oil and gas, but are manufactured from renewable resources.

As a result, there can be no assurance that we will be able to compete successfully or that competitive pressures will not adversely affect our business, results of operations, and financial condition. If we are not able to successfully compete in the marketplace, we could be forced to curtail or even abandon our current business plan, which could cause any investment in us to become worthless.

We may not be able to successfully manage our growth, which could lead to our inability to implement our business plan.

Our growth may place a significant strain on our managerial, operational and financial resources, especially considering that we currently only have a small number of executive officers, employees and advisors. Further, as we enter into additional contracts, we will be required to manage multiple relationships with various consultants, businesses and other third parties. These requirements will be exacerbated in the event of our further growth or in the event that the number of our drilling and/or extraction operations increases. There can be no assurance that our systems, procedures and/or controls will be adequate to support our operations or that our management will be able to achieve the rapid execution necessary to successfully implement our business plan. If we are unable to manage our growth effectively, our business, results of operations and financial condition will be adversely affected, which could lead to us being forced to abandon or curtail our business plan and operations.

Our operations are heavily dependent on current environmental regulation, changes in which we cannot predict.

Oil and natural gas activities that we will engage in, including production, processing, handling and disposal of hazardous materials, such as hydrocarbons and naturally occurring radioactive materials (if any), are subject to stringent regulation. We could incur significant costs, including cleanup costs resulting from a release of hazardous material, third-party claims for property damage and personal injuries fines and sanctions, as a result of any violations or liabilities under environmental or other laws. Changes in or more stringent enforcement of environmental laws could force us to expend additional operating costs and capital expenditures to stay in compliance.

Various federal, state and local laws regulating the discharge of materials into the environment, or otherwise relating to the protection of the environment, directly impact oil and gas exploration, development and production operations, and consequently may impact our operations and costs. These regulations include, among others, (i) regulations by the Environmental Protection Agency and various state agencies regarding approved methods of disposal for certain hazardous and non-hazardous wastes; (ii) the Comprehensive Environmental Response, Compensation, and Liability Act, Federal Resource Conservation and Recovery Act and analogous state laws which regulate the removal or remediation of previously disposed wastes (including wastes disposed of or released by prior owners or operators), property contamination (including groundwater contamination), and remedial plugging operations to prevent future contamination; (iii) the Clean Air Act and comparable state and local requirements which may result in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations; (iv) the Oil Pollution Act of 1990 which contains numerous requirements relating to the prevention of and response to oil spills into waters of the United States; (v) the Resource Conservation and Recovery Act which is the principal federal statute governing the treatment, storage and disposal of hazardous wastes; and (vi) state regulations and statutes governing the handling, treatment, storage and disposal of naturally occurring radioactive material.

Management believes that we will be in substantial compliance with applicable environmental laws and regulations. To date, we have not expended any amounts to comply with such regulations, and management does not currently anticipate that future compliance will have a materially adverse effect on our consolidated financial position, results of operations or cash flows. However, if we are deemed to not be in compliance with applicable environmental laws, we could be forced to expend substantial amounts to be in compliance, which would have a materially adverse effect on our financial condition. If this were to happen, any investment in us could be lost.

Government regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Vast quantities of natural gas, natural gas liquids and oil deposits exist in deep shale and other unconventional formations. It is customary in our industry to recover these resources through the use of hydraulic fracturing, combined with horizontal drilling. Hydraulic fracturing is the process of creating or expanding cracks, or fractures, in deep underground formations using water, sand and other additives pumped under high pressure into the formation. As with the rest of the industry, our third-party operating partners use hydraulic fracturing as a means to increase the productivity of most of the wells they drill and complete. These formations are generally geologically separated and isolated from fresh ground water supplies by thousands of feet of impermeable rock layers.

We believe our third-party operating partners follow applicable legal requirements for groundwater protection in their operations that are subject to supervision by state and federal regulators. Furthermore, we believe our third-party operating partners' well construction practices are specifically designed to protect freshwater aquifers by preventing the migration of fracturing fluids into aquifers.

Hydraulic fracturing is typically regulated by state oil and gas commissions. Some states have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, and/or well construction requirements on hydraulic fracturing operations. For example, Pennsylvania is currently considering proposed regulations applicable to surface use at oil and gas well sites, including new secondary containment requirements and an abandoned and orphaned well identification program that would require operators to remediate any such wells that are damaged during current hydraulic fracturing operations. New York has placed a permit moratorium on high volume fracturing activities combined with horizontal drilling pending the results of a study regarding the safety of hydraulic fracturing. And certain communities in Colorado have also enacted bans on hydraulic fracturing.

In addition to state laws, some local municipalities have adopted or are considering adopting land use restrictions, such as city ordinances, that may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. There are also certain governmental reviews either underway or being proposed that focus on deep shale and other formation completion and production practices, including hydraulic fracturing. Depending on the outcome of these studies, federal and state legislatures and agencies may seek to further regulate such activities. Certain environmental and other groups have also suggested that additional federal, state and local laws and regulations may be needed to more closely regulate the hydraulic fracturing process.

Further, the EPA has asserted federal regulatory authority over hydraulic fracturing involving "diesel fuels" under the SWDA's UIC Program and has released final guidance regarding the process for obtaining a permit for hydraulic fracturing involving diesel fuel. The EPA also has commenced a study of the potential impacts of hydraulic fracturing activities on drinking water resources, with a progress report released in late 2012 and a final draft report expected to be released for public comment and peer review in late 2014. The EPA's guidance, including its interpretation of the meaning of "diesel fuel," the EPA's pending study, and other analyses by federal and state agencies to assess the impacts of hydraulic fracturing could each spur further action toward federal and/or state legislation and regulation of hydraulic fracturing activities.

We cannot predict whether additional federal, state or local laws or regulations applicable to hydraulic fracturing will be enacted in the future and, if so, what actions any such laws or regulations would require or prohibit. Restrictions on hydraulic fracturing could make it prohibitive for our third-party operating partners to conduct operations, and also reduce the amount of oil, natural gas liquids and natural gas that we are ultimately able to produce in commercial quantities from our properties. If additional levels of regulation or permitting requirements were imposed on hydraulic fracturing operations, our business and operations could be subject to delays, increased operating and compliance costs and process prohibitions.

Our estimates of the volume of reserves could have flaws, or such reserves could turn out not to be commercially extractable. As a result, our future revenues and projections could be incorrect.

Estimates of reserves and of future net revenues prepared by different petroleum engineers may vary substantially depending, in part, on the assumptions made and may be subject to adjustment either up or down in the future. Our actual amounts of production, revenue, taxes, development expenditures, operating expenses, and quantities of recoverable oil and gas reserves may vary substantially from the estimates. Oil and gas reserve estimates are necessarily inexact and involve matters of subjective engineering judgment. In addition, any estimates of our future net revenues and the present value thereof are based on assumptions derived in part from historical price and cost information, which may not reflect current and future values, and/or other assumptions made by us that only represent our best estimates. If these estimates of quantities, prices and costs prove inaccurate, we may be unsuccessful in expanding our oil and gas reserves base with our acquisitions. Additionally, if declines in and instability of oil and gas prices occur, then write downs in the capitalized costs associated with any oil and gas assets we obtain may be required. Because of the nature of the estimates of our reserves and estimates in general, we can provide no assurance that reductions to our estimated proved oil and gas reserves and estimated future net revenues will not be required in the future, and/or that our estimated reserves will be present and/or commercially extractable. If our reserve estimates are incorrect, the value of our common stock could decrease and we may be forced to write down the capitalized costs of our oil and gas properties.

Decommissioning costs are unknown and may be substantial. Unplanned costs could divert resources from other projects.

We may become responsible for costs associated with abandoning and reclaiming wells, facilities and pipelines which we use for production of oil and natural gas reserves. Abandonment and reclamation of these facilities and the costs associated therewith is often referred to as "decommissioning." We accrue a liability for decommissioning costs associated with our wells, but have not established any cash reserve account for these potential costs in respect of any of our properties. If decommissioning is required before economic depletion of our properties or if our estimates of the costs of decommissioning exceed the value of the reserves remaining at any particular time to cover such decommissioning costs, we may have to draw on funds from other sources to satisfy such costs. The use of other funds to satisfy such decommissioning costs could impair our ability to focus capital investment in other areas of our business.

We may have difficulty distributing production, which could harm our financial condition.

In order to sell the oil and natural gas that we are able to produce, if any, the operators of the wells we obtain interests in may have to make arrangements for storage and distribution to the market. We will rely on local infrastructure and the availability of transportation for storage and shipment of our products, but infrastructure development and storage and transportation facilities may be insufficient for our needs at commercially acceptable terms in the localities in which we operate. This situation could be particularly problematic to the extent that our operations are conducted in remote areas that are difficult to access, such as areas that are distant from shipping and/or pipeline facilities. These factors may affect our and potential partners' ability to explore and develop properties and to store and transport oil and natural gas production, increasing our expenses.

Furthermore, weather conditions or natural disasters, actions by companies doing business in one or more of the areas in which we will operate, or labor disputes may impair the distribution of oil and/or natural gas and in turn diminish our financial condition or ability to maintain our operations.

Our business will suffer if we cannot obtain or maintain necessary licenses.

Our operations will require licenses, permits and in some cases renewals of licenses and permits from various governmental authorities. Our ability to obtain, sustain or renew such licenses and permits on acceptable terms is subject to change in regulations and policies and to the discretion of the applicable governments, among other factors. Our inability to obtain, or our loss of or denial of extension of, any of these licenses or permits could hamper our ability to produce revenues from our operations.

Challenges to our properties may impact our financial condition.

Title to oil and gas interests is often not capable of conclusive determination without incurring substantial expense. While we intend to make appropriate inquiries into the title of properties and other development rights we acquire, title defects may exist. In addition, we may be unable to obtain adequate insurance for title defects, on a commercially reasonable basis or at all. If title defects do exist, it is possible that we may lose all or a portion of our right, title and interests in and to the properties to which the title defects relate. If our property rights are reduced, our ability to conduct our exploration, development and production activities may be impaired. To mitigate title problems, common industry practice is to obtain a title opinion from a qualified oil and gas attorney prior to the drilling operations of a well.

We rely on technology to conduct our business, and our technology could become ineffective or obsolete.

We rely on technology, including geographic and seismic analysis techniques and economic models, to develop our reserve estimates and to guide our exploration, development and production activities. We and our operator partners will be required to continually enhance and update our technology to maintain its efficacy and to avoid obsolescence. The costs of doing so may be substantial and may be higher than the costs that we anticipate for technology maintenance and development. If we are unable to maintain the efficacy of our technology, our ability to manage our business and to compete may be impaired. Further, even if we are able to maintain technical effectiveness, our technology may not be the most efficient means of reaching our objectives, in which case we may incur higher operating costs than we would were our technology more efficient.

The loss of key personnel would directly affect our efficiency and profitability.

Our future success is dependent, in a large part, on retaining the services of our current management team. Our executive officers possess a unique and comprehensive knowledge of our industry and related matters that are vital to our success within the industry. The knowledge, leadership and technical expertise of these individuals would be difficult to replace. The loss of one or more of our officers could have a material adverse effect on our operating and financial performance, including our ability to develop and execute our long term business strategy. We do not maintain key-man life insurance with respect to any employees. We do have employment agreements with each of our executive officers. There can be no assurance, however, that any of our officers will continue to be employed by us.

Our officers and directors control a significant percentage of our current outstanding common stock and their interests may conflict with those of our stockholders.

As of the date of this report, our executive officers and directors collectively and beneficially own approximately 34.18% of our outstanding common stock (see Item 12 of this report for an explanation of how this number is computed). This concentration of voting control gives these affiliates substantial influence over any matters which require a stockholder vote, including without limitation the election of directors and approval of merger and/or acquisition transactions, even if their interests may conflict with those of other stockholders. It could have the effect of delaying or preventing a change in control or otherwise discouraging a potential acquirer from attempting to obtain control of us. This could have a material adverse effect on the market price of our common stock or prevent our stockholders from realizing a premium over the then prevailing market prices for their shares of common stock.

In the future, we may incur significant increased costs as a result of operating as a public company, and our management may be required to devote substantial time to new compliance initiatives.

In the future, we may incur significant legal, accounting, and other expenses as a result of operating as a public company. The Sarbanes-Oxley Act of 2002 (the “Sarbanes-Oxley Act”), as well as new rules subsequently implemented by the SEC, have imposed various requirements on public companies, including requiring changes in corporate governance practices. Our management and other personnel will need to devote a substantial amount of time to these new compliance initiatives. Moreover, these rules and regulations will increase our legal and financial compliance costs and will make some activities more time-consuming and costly. For example, we expect these new rules and regulations to make it more difficult and more expensive for us to obtain director and officer liability insurance, and we may be required to incur substantial costs to maintain the same or similar coverage.

In addition, the Sarbanes-Oxley Act requires, among other things, that we maintain effective internal controls for financial reporting and disclosure controls and procedures. In particular, we are required to perform system and process evaluation and testing on the effectiveness of our internal controls over financial reporting, as required by Section 404 of the Sarbanes-Oxley Act. In performing this evaluation and testing, management concluded that our internal control over financial reporting is effective as of December 31, 2014. We are performing ongoing updates of our policies and procedures in an effort to ensure our internal control remains effective. Our compliance with Section 404, will require that we incur substantial accounting expense and expend significant management efforts. We currently do not have an internal audit group, and we will need to engage independent professional assistance. Moreover, if we are not able to comply with the requirements of Section 404 in a timely manner, or if in the future we or our independent registered public accounting firm identifies deficiencies in our internal controls over financial reporting that are deemed to be material weaknesses, the market price of our stock could decline, and we could be subject to sanctions or investigations by the SEC or other regulatory authorities, which would require additional financial and management resources.

Certain Factors Related to Our Common Stock

There presently is a limited market for our common stock, and the price of our common stock may be volatile.

Our common stock is currently quoted on The NASDAQ Stock Market LLC. Our shares, however, are very thinly traded, and we have a very limited trading history. There could be volatility in the volume and market price of our common stock moving forward. This volatility may be caused by a variety of factors, including the lack of readily available quotations, the absence of consistent administrative supervision of “bid” and “ask” quotations, and generally lower trading volume. In addition, factors such as quarterly variations in our operating results, changes in financial estimates by securities analysts, or our failure to meet our or their projected financial and operating results, litigation involving us, factors relating to the oil and gas industry, actions by governmental agencies, national economic and stock market considerations, as well as other events and circumstances beyond our control could have a significant impact on the future market price of our common stock and the relative volatility of such market price.

We have received a notice of failure to satisfy a continued listing requirement of NASDAQ

On January 20, 2015, we received a letter from the Listing Qualifications Staff (the “Staff”) of The NASDAQ Stock Market advising us that the Staff has determined that for the last 30 consecutive business days, we no longer meet the requirement of Listing Rule 5550(a)(2) which requires us to maintain a minimum bid price of $1 per share. The Listing Rules provide us with a compliance period of 180 calendar days in which to regain compliance. Accordingly, we will regain compliance if at any time during this 180 day period the closing bid price of our common stock is at least $1 for a minimum of ten consecutive business days.

In the event we do not regain compliance by the end of the 180 day compliance period on July 20, 2015, we may be eligible for additional time. To qualify, we will be required to meet the continued listing requirement for market value of publicly held shares and all other initial listing standards for The Nasdaq Capital Market, with the exception of the bid price requirement, and will need to provide written notice of our intention to cure the deficiency during the second compliance period, by effecting a reverse stock split, if necessary. If we meet these requirements, the Staff will inform us that we have been granted an additional 180 calendar days. However, if it appears to the Staff that we will not be able to cure the deficiency, or if we are otherwise not eligible, the Staff will provide us notice that our common stock will be subject to delisting. At that time, we may appeal the delisting determination to a Hearings Panel.

We are currently reviewing our options to regain compliance with the NASDAQ Listing Rules. If we are unable to regain compliance and are ultimately delisted from NASDAQ, this may have a material adverse impact on our stockholders.

Offers or availability for sale of a substantial number of shares of our common stock may cause the price of our common stock to decline.

Our stockholders could sell substantial amounts of common stock in the public market, including shares sold upon the filing of a registration statement that registers such shares and/or upon the expiration of any statutory holding period under Rule 144 of the Securities Act of 1933 (the “Securities Act”), if available, or upon the expiration of trading limitation periods. Such volume could create a circumstance commonly referred to as a market “overhang” and in anticipation of which the market price of our common stock could fall. Additionally, we have a large number of convertible promissory notes that are presently convertible and warrants that are presently exercisable. The conversion or exercise of a large amount of these securities followed by the subsequent sale of the underlying stock in the market would likely have a negative effect on our common stock’s market price. The existence of an overhang, whether or not sales have occurred or are occurring, also could make it more difficult for us to secure additional financing through the sale of equity or equity-related securities in the future at a time and price that we deem reasonable or appropriate.

Our directors and officers have rights to indemnification.

Our Bylaws provide, as permitted by governing Nevada law, that we will indemnify our directors, officers, and employees, whether or not then in service as such, against all reasonable expenses actually and necessarily incurred by him or her in connection with the defense of any litigation to which the individual may have been made a party because he or she is or was a director, officer, or employee of the company. The inclusion of these provisions in the Bylaws may have the effect of reducing the likelihood of derivative litigation against directors and officers, and may discourage or deter stockholders or management from bringing a lawsuit against directors and officers for breach of their duty of care, even though such an action, if successful, might otherwise have benefited us and our stockholders.

We do not anticipate paying any cash dividends.

We do not anticipate paying cash dividends on our common stock for the foreseeable future. The payment of dividends, if any, would be contingent upon our revenues and earnings, if any, capital requirements, and general financial condition. The payment of any dividends will be within the discretion of our Board of Directors. We presently intend to retain all earnings, if any, to implement our business strategy; accordingly, we do not anticipate the declaration of any dividends in the foreseeable future.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not Applicable.

ITEM 2. PROPERTIES

Our principal executive offices are located at 5700 W. Plano Parkway, Suite 3600, Plano, Texas 75093. We currently lease this office space which totals approximately 3,181 square feet. We believe that the condition and size of our offices are adequate for our current needs.

Investment in oil and gas properties for 2014 is detailed as follows:

	2014	2013
Property acquisition costs	$ 7,222,793	$ 6,274,154
Development costs	11,368,536	3,885,730
Exploratory costs	$ -0-	$ -0-

Oil and Natural Gas Reserves

Reserve Estimates

SEC Case. The following tables sets forth, as of December 31, 2014, our estimated net proved oil and natural gas reserves, the estimated present value (discounted at an annual rate of 10%) of estimated future net revenues before future income taxes (PV-10) and after future income taxes (Standardized Measure) of our proved reserves and our estimated net probable oil and natural gas reserves, each prepared using standard geological and engineering methods generally accepted by the petroleum industry and in accordance with assumptions prescribed by the Securities and Exchange Commission ("SEC"). All of our reserves are located in the United States.

The PV-10 value is a widely used measure of value of oil and natural gas assets and represents a pre-tax present value of estimated cash flows discounted at ten percent. PV-10 is considered a non-GAAP financial measure as defined by the SEC. We believe that our PV-10 presentation is relevant and useful to our investors because it presents the estimated discounted future net cash flows attributable to our proved reserves before taking into account the related future income taxes, as such taxes may differ among various companies. We believe investors and creditors use PV-10 as a basis for comparison of the relative size and value of our proved reserves to the reserve estimates of other companies. PV-10 is not a measure of financial or operating performance under GAAP and neither it nor the Standardized Measure is intended to represent the current market value of our estimated oil and natural gas reserves. PV-10 should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP.

Our PV-10 at December 31, 2014 and 2013 is materially reconciled to our Standardized Measure of discounted cash flows at those dates by reducing the PV-10 by the discounted future income taxes associated with such reserves. The discounted future income taxes at December 31, 2014 and 2013, respectively, were $678,904 and $7,093,985.

The estimates of our proved reserves and the PV-10 set forth herein reflect estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs under existing economic conditions at December 31, 2014. For purposes of determining prices, we used the average of prices received for each month within the 12-month period ended December 31, 2014, adjusted for quality and location differences, which was $91.48 per barrel of oil and $4.35 per MCF of gas. This average historical price is not a prediction of future prices. The amounts shown do not give effect to non-property related expenses, such as corporate general administrative expenses and debt service, future income taxes or to depreciation, depletion and amortization.

Category	December 31, 2014 Reserves Oil (Bbls)	Gas (Mcf)	Total (BOE)	December 31, 2014 Future Net Revenue (M$) Total	Present Value Discounted at 10%
Proved Developed	120,000	687,000	234,500	$ 9,909	$ 7,670
Proved Undeveloped	794,400	3,104,000	1,311,733	$ 32,585	$ 16,026
Total Proved	914,400	3,791,000	1,546,233	42,494	23,696
Standardized Measure of Future Net Cash Flows Related to Proved Oil and Gas Properties					$ 23,019
Probable Undeveloped	912.400	0	912,400	$ 22,779	$ 8,558

Category	December 31, 2013 Reserves Oil (Bbls)	Gas (Mcf)	Total (BOE)	December 31, 2013 Future Net Revenue (M$) Total	Present Value Discounted at 10%
Proved Developed	113,092	313,251	165,301	$ 8,861	$ 6,117
Proved Undeveloped	930,069	2,826,344	1,401,126	$ 44,699	$ 20,408
Total Proved	1,043,161	3,139,595	1,566,427	$ 53,560	$ 26,525
Standardized Measure of Future Net Cash Flows Related to Proved Oil and Gas Properties					$ 19,691
Probable Undeveloped	657,800	0	657,800	$ 33,571	$ 16,253

BOE equivalents are determined by combining barrels of oil with MCF of gas divided by six.

The decrease of 89,393 BOE (89,285 for our Hunton Project and 108 for our Marcelina Project) in proved undeveloped reserves comes from the third party engineering studies of the Cimarron and Chisholm Trail AMI's in Oklahoma which were acquired by the Company in 2013 and engineering studies for our Marcelina Project.

No reserve value for the Ring Project is included in 2014 reserve tables presented above since the company believes this project is still considered to be in the testing phase.

ITEM 2. PROPERTIES - *continued*

Standardized Measure of Oil & Gas Quantities - Volume Rollforward
Years Ended December 31, 2014 and 2013

The following table sets forth the Company's net proved reserves, including the changes therein, and proved developed reserves:

	2014		2013	
	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)
TOTAL PROVED RESERVES:				
Beginning of period	1,043,161	3,139,594	417,549	-
Acquisition	-	-	572,461	3,139,595
Extensions and discoveries	312,579	-	101,180	-
Revisions of previous estimates	(388,485)	821,150	(34,743)	3,539
Production	(52,855)	(170,094)	(13,286)	(3,540)
End of period	914,400	3,790,650	1,043,161	3,139,594
PROVED DEVELOPED RESERVES				
Proved developed producing	102,479	488,410	64,858	108,001
Proved developed nonproducing	17,521	198,710	48,234	205,250
Total	120,000	687,120	113,092	313,251
Total PUD	794,400	3,103,530	930,069	2,826,344

The preceding table shows significant decrease in the Acquisition category for 2014 as compared to 2013. The 2013 Acquisition increase is all related to the working interest acquired in the Cimarron and the Chisholm Trail AMI's with Husky Ventures in Oklahoma during 2013. During 2014 the company focused on expanding its participation in the Chisholm Trail and Cimarron AMI'S in Oklahoma which accounts for the increase in Extensions and Discoveries for 2014.

The 2013 Revisions of Previous Estimates are composed of revisions to the proved producing and proved undeveloped reserves.

The downward revision of 388,485 BO results primarily from eliminating two Eagle Ford wells (which are now considered uneconomic at current prices) from reserve report calculations for the Company's properties in the Marcelina Creek Project in Texas. This reflects a reduction of 366,366 BO offset directly by an increase in reserves of 60,159 BO from the currently producing wells. The Johnson #1 is the largest contributor, with an increase of reserves of 56,783 BO. The Johnson #2 and #4 account for an additional increase of 3,376 BO. The remaining difference comes from reserve adjustments in the well data for the Oklahoma Properties reserve calculations for 2014.

The positive revision of 821,150 MCF of gas is attributable to gas production increase from the development activity in the Chisholm Trail and Cimarron AMI's in Oklahoma where the Company focused on expanding its participation in 2014 drilling and development. Gas reserves can be fully attributable to our Oklahoma joint venture operations. Most of our wells in the program are horizontally drilled wells that produce from the Hunton rock which requires a fracking stimulation to achieve the maximum production rates. Typically these wells have a relatively high initial production rates, but decline rapidly. Three wells in our Oklahoma ventures contribute 244.8 MMcf of the total improvement. As a result of the PDP wells success the offsetting PUD wells are expected to be significant contributors as well. Our other producing wells in Oklahoma are evenly spread.

Standardized Measure of Oil & Gas Quantities
Year Ended December 31, 2014 & 2013

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves is as follows :	2014	2013
Future cash inflows	$ 106,027,440	$ 119,629,906
Future production costs	(30,383,390)	(31,656,853)
Future development costs	(33,148,780)	(34,152,898)
Future income tax expense	(978,776)	(11,264,101)
Future net cash flows	41,516,494	42,556,054
10% annual discount for estimated timing of cash flows	(18,497,528)	(22,865,456)
Standardized measure of discounted future net cash flows related to proved reserves	$ 23,018,966	$ 19,690,598

A summary of the changes in the standardized measure of discounted future net cash flows applicable to proved oil and natural gas reserves is as follows :

Balance, beginning of year	$ 19,690,598	$ 2,909,000
Sales and transfers of oil and gas produced during the period	(4,310,813)	(905,125)
Net change in sales and transfer prices and in production (lifting) costs related to future production	(9,497,301)	(1,647,568)
Net change due to purchases of minerals in place	-	30,474,988
Net change due to extensions and discoveries	14,340,815	22,411,372
Changes in estimated future development costs	(13,990,412)	(17,355,723)
Previously estimated development costs incurred during the period	15,980,816	(3,181,356)
Net change due to revisions in quantity estimates	(12,814,002)	(4,633,853)
Other	2,487,713	(1,468,500)
Accretion of discount	4,715,661	(318,085)
Net change in income taxes	6,415,891	(6,594,552)
Balance, end of year	$ 23,018,966	$ 19,690,598

Due to the inherent uncertainties and the limited nature of reservoir data, both proved and probable reserves are subject to change as additional information becomes available. The estimates of reserves, future cash flows, and present value are based on various assumptions, including those prescribed by the SEC, and are inherently imprecise. Although we believe these estimates are reasonable, actual future production, cash flows, taxes, development expenditures, operating expenses, and quantities of recoverable oil and natural gas reserves may vary substantially from these estimates.

In estimating probable reserves, it should be noted that those reserve estimates inherently involve greater risk and uncertainty than estimates of proved reserves. While analysis of geoscience and engineering data provides reasonable certainty that proved reserves can be economically producible from known formations under existing conditions and within a reasonable time, probable reserves involve less certainty than reserves with a higher classification due to less data to support their ultimate recovery. Probable reserves have not been discounted for the additional risk associated with future recovery. Prospective investors should be aware that as the categories of reserves decrease with certainty, the risk of recovering reserves at the PV-10 calculation increases. The reserves and net present worth discounted at 10% relating to the different categories of proved and probable have not been adjusted for risk due to their uncertainty of recovery and thus are not comparable and should not be summed into total amounts.

Reserve Estimation Process, Controls and Technologies

The reserve estimates, including PV-10 estimates, set forth above were prepared by Netherland, Sewell & Associates, Inc. with respect to the Company's Marcelina Creek Project in Texas, and PeTech Enterprises, Inc. for the Company's properties in Oklahoma. A copy of their full reports with regard to our reserves is attached as Exhibit 99.1 to this annual report on Form 10-K. These calculations were prepared using standard geological and engineering methods generally accepted by the petroleum industry and in accordance with SEC financial accounting and reporting standards.

Our Chairman of our Board of Directors is an experienced and qualified geoscience professional with a degree in geophysical science, but we do not have any employees with specific reservoir engineering qualifications in the company. Our Chairman and Chief Executive Officer worked closely with Netherland, Sewell & Associates, Inc. and PeTech Enterprises Inc. in connection with their preparation of our reserve estimates, including assessing the integrity, accuracy, and timeliness of the methods and assumptions used in this process.

The reserves estimates for the Marcelina Creek Project included herein have been independently evaluated by Netherland, Sewell & Associates, Inc. (NSAI), a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical person primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein is Mr. Neil H. Little. Mr. Little, a Licensed Professional Engineer in the State of Texas (No. 117966), has been practicing consulting petroleum engineering at NSAI since 2011 and has over 9 years of prior industry experience. He graduated from Rice University in 2002 with a Bachelor of Science Degree in Chemical Engineering and from the University of Houston in 2007 with a Master of Business Administration Degree. Mr. Little meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; Mr. Little is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

PeTech Enterprises, Inc. ("PeTech"), who provided reserve estimates for our Oklahoma Properties, is a Texas based profitable, family owned oil and gas production and Investment Company that provides reservoir engineering, economics and valuation support to energy banks, energy companies and law firms as an expert witness. The company has been in business since 1982. Amiel David is the President of PeTech and the primary technical person in charge of the estimates of reserves and associated cash flow and economics on behalf of the company for the results presented in its reserves report to us. He has a PhD in Petroleum Engineering from Stanford University. He is a registered Professional Engineer in the state of Texas (PE #50970), granted in 1982, a member of the Society of Petroleum Engineers and a member of the Society of Petroleum Evaluation Engineers.

Proved Undeveloped Reserves

As of December 31, 2014, our proved undeveloped reserves totaled 1,311,733 barrels of oil equivalents compared to 1,401,126 as of December 31, 2013, a decrease of 89,393. These proved undeveloped reserves at December 31, 2014 were associated with our Marcelina Creek Field property (which decreased by 108) and our Hunton projects (which account for the decrease of 89,285). These numbers are taken from the third party reserves studies by Netherland, Sewell & Associates, Inc. and PeTech.

This decrease of 89,825 BOE in proved undeveloped reserves attributable to our Hunton projects comes from the third party engineering study from PeTech of the Cimarron and Chisholm Trail AMI's in Oklahoma. The net reserves change associated with these properties is a decrease of approximately 28 Mbbl of oil and an increase of approximately 278 MMcf of gas, or 46 MBOE calculated with a gas-oil equivalency factor of six. We acquired an interest in the Boeckman 1-14H well in May 2013, representing our first property in Oklahoma. Over the course of 2013, we acquired interests in five wells that were producing by December 31, 2013 and acquired interests in six other wells that were drilled and completed, but not producing, by December 31, 2013. During 2014 we acquired interest in eleven wells that were producing at December 31, 2014.

With respect to our Marcelina Project, the decrease in proved undeveloped reserves of 108 BO in Texas is due to a combination of factors. This reduction was based on analysis by Netherland, Sewell & Associates, Inc. of performance for offset Eagle Ford producers adjacent to the Company's lease.

We made various investments and progress during 2014 to convert proved undeveloped reserves to proved developed reserves. The capital expenditures incurred in converting our proved undeveloped reserves to developed were approximately $16,240,288. We believe that nearly all of our proved undeveloped reserves as of December 31, 2014 will be developed within five years. Limitations on our ability to develop proved undeveloped reserves within five years would likely be due to restraints on our capital and/or personnel moving forward. The restraints, however, could be alleviated through increased revenue or additional funding.

Our current drilling plans, subject to sufficient capital resources and the periodic evaluation of interim drilling results and other potential investment opportunities, include drilling substantially all of the Buda wells in our proved undeveloped reserves during 2015 and 2016. We do not currently have plans to drill the Eagle Ford shale wells in the next year. The area of the Marcelina Creek Field is an active area of Eagle Ford shale development, and we intend to actively explore our options with regard to these proved undeveloped locations and other potential Eagle Ford drilling locations on our acreage. Further we will maintain our continuous drilling program in the Hunton projects for the foreseeable future.

Production, Price, and Production Cost History

During the year ended December 31, 2014, we produced and sold 56,915 barrels of oil net to our interest at an average sale price of $90.58 per bbl. We produced and sold 170,094 MCF of gas net to our interest at an average sales price of $5.89 per MCF. Our average production cost including lease operating expenses and direct production taxes was $14.63 per BOE. Our depreciation, depletion, and amortization expense was $30.43 per BOE.

During the year ended December 31, 2013, we produced and sold 13,286 barrels of oil net to our interest at an average sale price of $100.67 per bbl. We produced and sold 3.540 MCF of gas net to our interest at an average sales price of $5.68 per MCF.Our average production cost including lease operating expenses and direct production taxes was $31.29 per bbl. Our depreciation, depletion, and amortization expense was $49.09 per bbl.

Our production is from properties concentrated in central Oklahoma and in southern Texas. Reserves from each of these areas comprise more than 15% of total reserves. For 2014, approximately 14,391 BO was produced at Marcelina Creek and approximately 66,993 BOE in Oklahoma, or 17% from Marcelina Creek and 78% from Oklahoma.

Quarterly Revenue and Production by State for 2013 and 2014 are detailed as follows:

Property	Quarter	Oil Production {BBLS}	Gas Production {MCF}	Oil Revenue ($)	Gas Revenue ($)	Total Revenue ($)
Marcelina	Q1 - 2013	2,255	0	$ 229,204	$ -	$ 229,204
Oklahoma	Q1 - 2013	0	0	$ -	$ -	$ -
Total Q1		2,255	0	$ 229,204	$ -	$ 229,204
Marcelina	Q2 - 2013	1,673	0	$ 160,823	$ -	$ 160,823
Oklahoma	Q2 - 2013	0	0	$ -	$ -	$ -
Total Q2		1,673	0	$ 160,823	$ -	$ 160,823
Marcelina	Q3 - 2013	3,896	0	$ 387,872	$ -	$ 387,872
Oklahoma	Q3 - 2013	316	1,321	$ 7,064	$ -	$ 7,064
Total Q3		4,212	1,321	$ 394,936	$ -	$ 394,936
Marcelina	Q4 - 2013	4,626	0	$ 401,956	$ -	$ 401,956
Oklahoma	Q4 - 2013	519	2,220	$ 47,793	$ 9,286	$ 57,079
Total Q4		5,145	2,220	449,749	9,286	459,035
Year ended 12/31/13		13,286	3,541	1,234,712	9,286	1,243,998

Property	Quarter	Oil Production {BBLS}	Gas Production {MCF}	Oil Revenue	Gas Revenue	Total Revenue
Marcelina	Q1 - 2014	3,888	-	$ 360,074	$ -	$ 360,074
Oklahoma	Q1 - 2014	2,326	7,366	$ 233,686	$ 49,210	$ 282,896
Total Q1-2014		6,214	7,366	$ 593,760	$ 49,210	$ 642,970
Marcelina	Q2 - 2014	4,546	-	$ 368,937	$ -	368,937
Oklahoma	Q2 - 2014	9,660	33,584	$ 899,709	$ 189,073	1,088,782
Kansas	Q2 - 2014	2,059	-	$ 172,316	$ -	172,316
Total Q2-2014		16,265	33,584	$ 1,440,962	$ 189,073	$ 1,630,035
Marcelina	Q3 - 2014	3,189	-	$ 289,230	$ -	$ 289,230
Oklahoma	Q3 - 2014	13,900	35,951	$ 1,346,858	$ 185,830	$ 1,532,688
Kansas	Q3 - 2014	1,257	-	$ 119,797	$ -	$ 119,797
Total Q3-2014		18,346	35,951	$ 1,755,885	$ 185,830	$ 1,941,715
Marcelina	Q4 - 2014	2,768	-	$ 118,132	$ -	$ 118,132
Oklahoma	Q4 - 2014	12,578	93,193	$ 663,053	$ 429,960	$ 1,093,013
Kansas	Q4 - 2014	744	-	$ 29,690	$ -	$ 29,690
Total Q3-2014		16,090	93,193	810,875	429,960	1,240,835
Year Ended 12/31/14		**56,915**	**170,094**	**$ 4,601,482**	**$ 854,073**	**$ 5,455,555**

Drilling Activity and Productive Wells

Marcelina Creek Project - Texas

During the year ended December 31, 2010, the Company participated in drilling operations of one re-entry and horizontal extension to an existing well bore (50% working interest). This well was recompleted in 2012 as a successful producing oil well.

During the year ended December 31, 2011, the Company drilled one well (75% working interest). This well was successfully completed as an oil well.

During the year ended December 31, 2012, the Company participated in another re-entry and horizontal extension to the same well drilled in 2010 (50% working interest). This operation was successful and the well is currently a producing oil well. We also participated in a re-entry and horizontal extension of another well (40% working interest), the Coulter #1. This well is currently testing as described above. For 2012, in Marcelina Creek the Company had a total of three producing wells at year end

During the year ended December 31, 2013, the Company drilled one well in the Marcelina Project (75% working interest). This well was successfully completed as an oil well.

As of December 31, 2014, we had three productive wells in the Marcelina Creek Field (2.00 net wells) and one well which was in the process of being tested in the Coulter Field (.40 net well). Net wells consist of the sum of our fractional working interests in these wells.

Central Oklahoma Projects

During the year ended December 31, 2013, the Company began participating in development wells in the Hunton Play. Two producing wells were acquired and three wells were drilled and completed in 2013. During 2014 the Company increased its participation by expanding its lease positions and drilling in the Cimarron, Chisholm Trail, Prairie Grove, and Viking AMI's. As of December 31, 2014, 10 wells were producing in the Cimarron, 11 wells in the Chisholm Trail, one in Prairie Grove, and one in the Viking. One additional well in the Viking was completing at the end of 2014.

ITEM 2. PROPERTIES - *continued*

Combined Well Status

The following table summarizes drilling activity and Well Status at December 31, 2014:

Drilling Activity/Well Status	Cumulative Well Status at 12/31/2014		2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development Wells:								
Productive -Texas	3.00	2.00	0.00	0.00	1.00	0.75	1.00	0.75
Productive - Okla	19.00	1.85	18.00	1.64	1.00	0.21	0.00	0.00
Productive - Kansas	5.00	2.90	5.00	2.90	0.00	0.00	0.00	0.00
Dry	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Exploration Wells:								
Productive	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Dry	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Drilled Wells:								
Productive -Texas	3.00	2.00	0.00	0.00	1.00	0.75	1.00	0.75
Productive - Okla	19.00	1.85	18.00	1.64	1.00	0.21	0.00	0.00
Productive - Kansas	5.00	2.90	5.00	2.90	0.00	0.00	0.00	0.00
Dry	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Acquired Wells:								
Productive -Texas	1.00	0.40	0.00	0.00	0.00	0.00	1.00	0.40
Productive - Okla	5.00	0.19	2.00	0.18	3.00	0.01	0.00	0.00
Productive - Kansas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Wells:								
Productive -Texas	4.00	2.40	0.00	0.00	1.00	0.75	2.00	1.15
Productive - Okla	24.00	2.04	20.00	1.82	4.00	0.22	0.00	0.00
Productive - Kansas	5.00	2.90	5.00	2.90	0.00	0.00	0.00	0.00
Total	33.00	7.34	25.00	4.72	5.00	0.97	2.00	1.15

ITEM 2. PROPERTIES - *continued*

Our acreage positions at December 31, 2014 are summarized as follows:

	Total Acres		TRCH Interest Developed Acres		TRCH Interest Undeveloped Acres	
Leasehold Interests - 12/31/2014	Gross	Net	Gross	Net	Gross	Net
Texas -						
Marcelina Creek	1,045	714	360	230	685	484
Orogrande	131,846	131,846	0	0	131,846	131,846
Coulter Field	940	376	940	376	0	0
Oklahoma -						
Cimmarron	5,020	753	3,785	410	1,235	343
Chisholm Trail	12,927	2,327	5,332	498	7,595	1,829
Viking	7,735	2,321	240	55	7,495	2,266
R4	11,745	3,524	0	0	11,745	3,523
Prairie Grove	640	64	640	64	0	0
T4	2,325	581	0	0	2,325	581
Kansas -						
Smokey Hill	960	171	960	171	0	0
Ring JV	1,320	1,320	1,320	1,320	0	0
Total	176,503	143,996	13,577	3,125	162,926	140,871

The Marcelina Creek Project consists of 1,045 gross acres all of which are held by production.

The Orogrande Project was acquired in September, 2014 through a Purchase Agreement with Hudspeth Oil Corporation ("Hudspeth"), McCabe Petroleum Corporation ("MPC"), and Greg McCabe. Mr. McCabe is the sole owner of both Hudspeth and MPC. Under the terms and conditions of the Purchase Agreement, at closing, we purchased 100% of the capital stock of Hudspeth which holds certain oil and gas assets, including a 100% working interest in 172,000 mostly contiguous acres in the Orogrande Basin in West Texas. This acreage is in the primary term under five-year leases that carry additional five-year extension provisions

Of the 172,000 acres 40,154 were scheduled for renewal in December, 2014. As of December 31, 2014 the Company had not renewed the leases. The Company is in discussions regarding renewal at the date of this filing.

Prior to March 31, 2015, the Company had the obligation to begin drilling its first well in order to hold the acreage block. The well was permitted and spudded by March 31 and drilling is in progress at date of this filing

The Central Oklahoma Projects acreage is in five AMI's as of December 31, 2014 with a combined total of 40,392 total gross acres. Producing wells (24) comprise 9,997 gross developed acres with the balance subject to a managed drilling program to retain leases for long term development. The leases have two to three year terms. The drilling program being executed will hold the leases by production within those terms

The Smokey Hills acquisition included approximately 16,000 gross acres and a well, the Hoffman 1-H within the greater Lindsborg Field area. Since development did not continue after the analysis of the Hoffman well and the disappointing results from the initial drilling/testing program in 2014, the acreage position declined from approximately 16,000 acres at acquisition to 960 developed acres at December 31, 2014. The property was offered for sale in the first quarter, 2015.

In October 2013, we entered into a Joint Venture agreement with Ring Energy. The agreement called for us to provide for $6.2 million in drilling capital to, in effect, match Ring Energy's expenditures for leasing. In exchange for this commitment, we would receive a 50% interest in each well bore drilled and the acreage unit it held, until we had spent $6.2 million. At such time, we would then receive a 50% Working Interest in the entire lease block consisting of 17,000 +/- acres. We were to provide $3.1 million in advance of the program commencing, which would cover approximately 5 wells to be drilled and completed. Once the initial five wells are completed, we and Ring would evaluate the program and the drilling activity and determine if another five wells are to be drilled. Should we continue with the program, we would then deposit another $3.1 million with Ring for drilling and completion of the next five wells

We made the initial $3.1 million deposit and the first five well drilling program is currently underway. Well locations were selected and drilling operations commenced in March, 2014. As of December 31, 2014 seven wells have been drilled – three are producing, one can be converted to a salt water disposal well, one was not completed, and two were plugged and abandoned. A decision has been made to acquire 3-D seismic data to assist the selection of future drill sites. Daily production at December 31, 2014 was approximately 33 BOPD.

As of December 30, 2014, the Company had invested approximately $4,500,000 in the Ring Joint Venture.

Net total gross acres in all areas are 143,996 at December 31, 2014.

ITEM 3. LEGAL PROCEEDINGS

None

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable.

PART II

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

Our common stock is quoted on The NASDAQ Stock Market LLC under the symbol, "TRCH." Trading in our common stock in the over-the-counter market has historically been limited and occasionally sporadic and the quotations set forth below are not necessarily indicative of actual market conditions. The high and low sales prices for the common stock for each quarter of the fiscal years ended December 31, 2014 and 2013, according to NASDAQ, were as follows:

Quarter Ended	High	Low
December 31, 2014	$ 3.59	$ 0.64
September 30, 2014	$ 4.20	$ 3.25
June 30, 2014	$ 5.41	$ 3.10
March 31, 2014	$ 5.41	$ 4.15
December 31, 2013	$ 6.75	$ 2.65
September 30, 2013	$ 3.50	$ 1.85
June 30, 2013	$ 2.34	$ 1.70
March 31, 2013	$ 2.31	$ 1.75

Record Holders

As of April 7, 2015, there were approximately 206 stockholders of record holding a total of 23,478,441 shares of common stock. Because many of our shares of common stock are held by brokers and other institutions on behalf of stockholders, we are unable to estimate the total number of stockholders represented by these record holders.

The holders of the common stock are entitled to one vote for each share held of record on all matters submitted to a vote of stockholders. Holders of the common stock have no preemptive rights and no right to convert their common stock into any other securities. There are no redemption or sinking fund provisions applicable to the common stock.

Dividends

We have not declared any cash dividends since inception and do not anticipate paying any dividends in the foreseeable future. The payment of dividends is within the discretion of the Board of Directors and will depend on our earnings, capital requirements, financial condition, and other relevant factors. There are no restrictions that currently limit our ability to pay dividends on our common stock other than those generally imposed by applicable state law.

Equity Compensation Plan Information

As of December 31, 2014, we did not have any compensation plans (including individual compensation arrangements) under which our equity securities are authorized for issuance.

Sales of Unregistered Securities

Other than the sale below, all equity securities that we have sold during the period covered by this report that were not registered under the Securities Act have previously been included in a Quarterly Report on Form 10-Q or in a Current Report on Form 8-K.

In November 2014, we issued 75,000 warrants to a consultant as compensation for services. The warrants have a term of three years and an exercise price of $5.00 per share. The securities were issued under the exemption from registration provided by Section 4(a)(2) of the Securities Act of 1933 and the rules and regulations promulgated thereunder. The issuance of securities did not involve a "public offering" based upon the following factors: (i) the issuance of securities was an isolated private transaction; (ii) a limited number of securities were issued to a single purchaser; (iii) there were no public solicitations; (iv) the investment intent of the purchaser; and (v) the restriction on transferability of the securities issued.

In December 2014, we issued 150,000 warrants to a major shareholder in connection with the loaning of funds to the issuer under a promissory note. The warrants have a term of three years and an exercise price of $1.00 per share. The securities were issued under the exemption from registration provided by Section 4(a)(2) of the Securities Act of 1933 and the rules and regulations promulgated thereunder. The issuances of securities did not involve a "public offering" based upon the following factors: (i) the issuances of securities were an isolated private transaction; (ii) a limited number of securities were issued to a single purchaser; (iii) there were no public solicitations; (iv) the purchaser represented that it was an "accredited investor"; (v) the investment intent of the purchaser; and (vi) the restriction on transferability of the securities issued.

In November 2014, an investor exercised warrant agreements to purchase a total of 15,000 shares of common stock at a price of $2.50 per share. The securities were issued under the exemption from registration provided by Section 4(a)(2) of the Securities Act of 1933 and the rules and regulations promulgated thereunder. The issuances of securities did not involve a "public offering" based upon the following factors: (i) each issuance of securities was an isolated private transaction; (ii) a limited number of securities were issued to a limited number of purchasers; (iii) there were no public solicitations; (iv) the purchaser previously represented that it was an "accredited investor"; (v) the investment intent of the purchaser; and (vi) the restriction on transferability of the securities issued.

In November 2014, we issued 32,500 shares of restricted common stock in connection with the settlement of a lawsuit. The securities were issued under the exemption from registration provided by Section 4(a)(2) of the Securities Act of 1933 and the rules and regulations promulgated thereunder. The issuance of securities did not involve a "public offering" based upon the following factors: (i) the issuance of securities was an isolated private transaction; (ii) a limited number of securities were issued to a single purchaser; (iii) there were no public solicitations; (iv) the investment intent of the purchaser; and (v) the restriction on transferability of the securities issued.

In November 2014, we issued 200,000 shares of restricted stock to a consultant as compensation for services. The securities were issued under the exemption from registration provided by Section 4(a)(2) of the Securities Act of 1933 and the rules and regulations promulgated thereunder. The issuance of securities did not involve a "public offering" based upon the following factors: (i) the issuance of securities was an isolated private transaction; (ii) a limited number of securities were issued to a single purchaser; (iii) there were no public solicitations; (iv) the investment intent of the purchaser; and (v) the restriction on transferability of the securities issued.

ITEM 6. SELECTED FINANCIAL DATA

Not Applicable.

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

Information set forth and discussed in this Management's Discussion and Analysis and Results of Operations is derived from our historical financial statements and the related notes thereto which are included in this Form 10-K. The following information and discussion should be read in conjunction with such financial statements and notes. Additionally, this Management's Discussion and Analysis and Plan of Operations contain certain statements that are not strictly historical and are "forward-looking" statements within the meaning of the Private Securities Litigation Reform Act of 1995 and involve a high degree of risk and uncertainty. Actual results may differ materially from those projected in the forward-looking statements due to other risks and uncertainties that exist in our operations, development efforts, and business environment, and due to other risks and uncertainties relating to our ability to obtain additional capital in the future to fund our planned expansion, the demand for oil and natural gas, and other general economic factors.

All forward-looking statements included herein are based on information available to us as of the date hereof, and we assume no obligation to update any such forward-looking statements.

Basis of Presentation of Financial Information

On November 23, 2010, the Share Exchange Agreement (the "Exchange Agreement" or "Transaction") between Pole Perfect Studios, Inc. ("PPS") and Torchlight Energy, Inc. ("TEI") was entered into and closed, through which the former shareholders of TEI became shareholders of PPS. At closing, PPS abandoned its previous business. Consequently, as a result of the Transaction, the business of TEI became our sole business.

Summary of Key Results

Overview

We are engaged in the acquisition, exploration, exploitation, and/or development of oil and natural gas properties in the United States.

The following discussion of our financial condition and results of operations should be read in conjunction with our audited financial statements included herewith for the year ended December 31, 2013. This discussion should not be construed to imply that the results discussed herein will necessarily continue into the future, or that any conclusion reached herein will necessarily be indicative of actual operating results in the future. Such discussion represents only the best present assessment by our management.

We had no active operations prior to the inception of TEI on June 25, 2010 and had limited revenues prior to the year ended December 31, 2012.

Historical Results for the Years Ended December 31, 2014 and 2013

Revenues and Cost of Revenues

For the year ended December 31, 2014, we had production revenue of $5,455,555 compared to $1,243,998 of production revenue for the year ended December 31, 2013 Refer to the table of production and revenue for 2014 included below. Our cost of revenue, consisting of lease operating expenses and production taxes, was $1,253,090, and $434,119 for the years ended December 31, 2014 and 2013, respectively. Production and Revenue are detailed as follows:

Property	Quarter	Oil Production {BBLS}	Gas Production {MCF}	Oil Revenue	Gas Revenue	Total Revenue
Marcelina	Q1 - 2014	3,888	-	$ 360,074	$ -	$ 360,074
Oklahoma	Q1 - 2014	2,326	7,366	$ 233,686	$ 49,210	$ 282,896
Total Q1-2014		6,214	7,366	$ 593,760	$ 49,210	$ 642,970
Marcelina	Q2 - 2014	4,546	-	$ 368,937	$ -	368,937
Oklahoma	Q2 - 2014	9,660	33,584	$ 899,709	$ 189,073	1,088,782
Kansas	Q2 - 2014	2,059	-	$ 172,316	$ -	172,316
Total Q2-2014		16,265	33,584	$ 1,440,962	$ 189,073	$ 1,630,035
Marcelina	Q3 - 2014	3,189	-	$ 289,230	$ -	$ 289,230
Oklahoma	Q3 - 2014	13,900	35,951	$ 1,346,858	$ 185,830	$ 1,532,688
Kansas	Q3 - 2014	1,257	-	$ 119,797	$ -	$ 119,797
Total Q3-2014		18,346	35,951	$ 1,755,885	$ 185,830	$ 1,941,715
Marcelina	Q4 - 2014	2,768	-	$ 118,132	$ -	$ 118,132
Oklahoma	Q4 - 2014	12,578	93,193	$ 663,053	$ 429,960	$ 1,093,013
Kansas	Q4 - 2014	744	-	$ 29,690	$ -	$ 29,690
Total Q3-2014		16,090	93,193	810,875	429,960	1,240,835
Year Ended 12/31/14		**56,915**	**170,094**	**$ 4,601,482**	**$ 854,073**	**$ 5,455,555**

We recorded depreciation, depletion and amortization expense of $2,736,562 for the year ended December 31, 2014.

General and Administrative Expenses

Our general and administrative expenses for the years ended December 31, 2014 and 2013 were $10,156,307 and $6,682,377, respectively, an increase of $3,473,930. Our general and administrative expenses consisted of consulting and compensation expense, substantially all of which was non-cash or deferred, accounting and administrative costs, professional consulting fees, and other general corporate expenses. The increase in general and administrative expenses for the year ended December 31, 2014 compared to 2013 is detailed as follows:

Increase in non cash stock and warrant compensation	$	1,312,885
Increase in accretion expense	$	1,876,661
Increase in capital funding expense	$	431,724
Increase(decrease) in consulting expense	$	(783,497)
Increase(decrease) in investor relations expense	$	(1,101,825)
Increase in legal, auditing, and professional	$	550,736
Increase in salaries and compensation	$	639,989
Increase in general corporate expenses	$	547,257
Total Increase in General and Administrative Expenses	$	3,473,930

Liquidity and Capital Resources

At December 31, 2014, we had working capital of $(11,873,048), current assets of $1,179,577 consisting of cash, accounts receivable, and prepaid expenses, and total assets of $36,150,364 consisting of current assets, investments in oil and gas properties, and other assets. As of December 31, 2014, we had current liabilities of $13,052,625, consisting of accounts payable, payables to related parties, notes payable (including our Series A Convertible Secured Notes), and accrued interest, and stockholders' equity was $19,117,745.

Cash flow provided (used) in operating activities for the years ended December 31, 2014, was $341,557 compared to $(2,262,636) for the year ended December 31, 2013, an increase of $2,604,193. Cash flow used in operating activities during 2014 can be primarily attributed to net losses from operations of $15,809,603, which consists primarily of $10,156,307 in general and administrative expenses ($5,644,028 of which are non-cash stock based compensation), depreciation, depletion, and amortization of $2,736,562, and accretion of convertible note discounts of $5,771,050. Cash flow used in operating activities during 2013 can be primarily attributed to net losses from operations of $10,418,662, which consists primarily of $6,682,377 in general and administrative expenses ($4,331,143 of which are non-cash stock based compensation), depreciation, depletion, and amortization of $652,179, and accretion of convertible note discounts of $3,894,389.

Cash flow used in investing activities for year ended December 31, 2014 was $18,645,289 compared to $8,587,104 for the year ended December 31, 2013. Cash flow used in investing activities consists primarily of oil and gas investment properties acquired during the year ended December 31, 2014.

Cash flow provided by financing activities for the year ended December 31, 2014 was $16,671,806 as compared to $12,598,201 for the year ended December 31, 2013. Cash flow provided by financing activities in 2014 consists of convertible promissory notes issued for cash, net of repayments of debt, and proceeds from common stock issues and warrant exercises. We expect to continue to have cash flow provided by financing activities as we seek new rounds of financing and continue to develop our oil and gas investments.

Our current assets are insufficient to meet our current obligations or to satisfy our cash needs over the next twelve months and as such we will require additional debt or equity financing to meet our plans and needs. We face obstacles in continuing to attract new financing due to our history and current record of net losses and working capital deficits. All outstanding principal of our 12% Series A Secured Convertible Notes payable totaling $8,117,598 plus interest were due in full at their March 31, 2015 maturity. The Company is lacking the liquidity at the date of this filing (April, 2015) to repay the notes in full and is, therefore, in default. Management is actively pursuing and is in negotiations to take steps needed to cure the default as of the date of this filing. Despite our efforts, we can provide no assurance that we will be able to obtain the financing required to meet our stated objectives or even to continue as a going concern.

We do not expect to pay cash dividends in the foreseeable future.

Commitments and Contingencies

We are subject to contingencies as a result of environmental laws and regulations. Present and future environmental laws and regulations applicable to our operations could require substantial capital expenditures or could adversely affect our operations in other ways that cannot be predicted at this time. As of December 31, 2014 and December 31, 2013, no amounts have been recorded because no specific liability has been identified that is reasonably probable of requiring us to fund any future material amounts.

We currently have interests in five oil and gas projects, the Marcelina Creek Field Development in Wilson County, Texas, the Coulter Field in Waller County, Texas, projects in Logan and Kingfisher counties, Oklahoma and projects in McPherson, and Gray and Finney counties in Kansas. See the description under “Current Projects” above under “Item 1. Business” for more information and disclosure regarding commitments and contingencies relating to these projects.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Not Applicable.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

Board of Directors and Stockholders
Torchlight Energy Resources, Inc.
Plano, Texas

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have audited the accompanying consolidated balance sheets of Torchlight Energy Resources, Inc. (the "Company") as of December 31, 2014 and 2013, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the years then ended. These consolidated financial statements are the responsibility of the entity's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2014 and 2013, and the results of its operations and its cash flows for each of 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 entity will continue as a going concern. As discussed in Note 2 to the consolidated financial statements, the entity has suffered recurring losses from operations, has a net working capital deficiency, and is in default relating to certain convertible promissory notes which raises substantial doubt about its ability to continue as a going concern. Management's plans in regard to these matters are also described in Note 2. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

/s/ Calvetti Ferguson

Houston, Texas
April 15, 2015

TORCHLIGHT ENERGY RESOURCES, INC.
CONSOLIDATED CONDENSED BALANCE SHEETS

	December 31, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash	$ 179,787	$ 1,811,713
Accounts receivable	223,371	429,699
Production revenue receivable	210,435	-
Note receivable	515,748	-
Prepayments - development costs	20,602	-
Prepaid expenses	29,634	9,144
Total current assets	1,179,577	2,250,556
Investment in oil and gas properties, net	34,498,681	13,038,751
Office Equipment	55,150	11,604
Debt issuance costs, net	353,733	920,947
Goodwill	-	447,084
Other Assets	63,223	74,379
TOTAL ASSETS	$ 36,150,364	$ 16,743,321
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 4,018,306	$ 985,123
Accrued liabilities	240,000	-
Related party payables	90,000	90,000
Convertible promissory notes, net of discount of $700,178	7,417,420	-
Notes payable within one year	829,719	753,904
Due to working interest owners	73,439	580,484
Interest payable	383,741	309,498
Total current liabilities	13,052,625	2,719,009
Convertible promissory notes, net of discount of $625,457 at December 31, 2014 and $5,500,462 at December 31, 2013	3,944,043	4,802,711
Asset retirement obligation	35,951	24,382
Commitments and contingencies	-	-
Stockholders' equity:		
Preferred stock, par value $.001, 10,000,000 shares authorized, no shares issued or outstanding	-	-
Common stock, par value $0.001 per share; 75,000,000 shares authorized; 23,235,441 issued and outstanding at December 31, 2014 16,141,765 issued and outstanding at December 31, 2013	23,235	16,142
Additional paid-in capital	43,108,752	21,978,616
Warrants outstanding	7,636,320	3,043,420
Accumulated deficit	-31,650,561	-15,840,959
Total stockholders' equity	19,117,745	9,197,219
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 36,150,364	$ 16,743,321

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

TORCHLIGHT ENERGY RESOURCES, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS

	YEAR ENDED December 31, 2014	YEAR ENDED December 31, 2013
Revenue		
Oil and gas sales	$ 5,455,555	$ 1,243,998
SWD and royalties	85,529	51,501
Cost of revenue	(1,253,090)	(434,119)
Gross income	4,287,994	861,380
Operating expenses:		
General and administrative expense	10,156,307	6,682,377
Depreciation, depletion and amortization	2,736,562	652,179
Total operating expenses	12,892,869	7,334,556
Other income (expense)		
Income - Cancellation of Debt	22,748	660,000
Impairment expense	(447,084)	-
Interest income	69	59
Interest and accretion expense	(6,780,461)	(4,605,545)
Total other income (expense)	(7,204,728)	(3,945,486)
Net loss before taxes	(15,809,603)	(10,418,662)
Provision for income taxes	-	-
Net (loss)	$ (15,809,603)	$ (10,418,662)
Loss per share:		
Basic and Diluted	$ (1.01)	$ (0.74)
Weighted average shares outstanding:		
Basic and Diluted	15,728,621	14,016,240

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

TORCHLIGHT ENERGY RESOURCES, INC.
CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

	Common stock shares	Common stock amount	Additional paid-in capital	Accumulated deficit	Warrants Outstanding	Total
Balance, December 31, 2012	13,564,815	$ 13,565	$ 8,380,992	$ (5,422,296)	$ -	$ 2,972,260
Issuance of common stock for cash	212,500	$ 213	$ 849,787	$ -	$ -	$ 850,000
Issuance of common stock for services	735,752	$ 735	$ 1,438,245	$ -	$ -	$ 1,438,980
Issuance of common stock - mineral interests	558,356	$ 558	$ 1,233,409	$ -	$ -	$ 1,233,967
Issuance of common stock in warrant exercise	101,714	$ 102	$ 203,326	$ -	$ -	$ 203,428
Warrants issued with promissory notes	-	$ -	$ 3,332,649	$ -	$ -	$ 3,332,649
Warrants issued in private placement	-	$ -	$ (123,250)	$ -	$ 123,250	$ -
Warrants issued for services	-	$ -	$ -	$ -	$ 2,920,170	$ 2,920,170
Common stock issued in conversion of notes	968,628	$ 969	$ 1,694,123	$ -	$ -	$ 1,695,092
Beneficial conversion feature on conv. notes	-	$ -	$ 4,969,326	$ -	$ -	$ 4,969,326
Warrants issued for services	-	$ -	$ -	$ -	$ -	$ -
Net loss	-	$ -	$ -	$ (10,418,662)	$ -	$ (10,418,662)
Balance, December 31, 2013	16,141,765	$ 16,142	$ 21,978,607	$ (15,840,958)	$ 3,043,420	$ 9,197,210
Issuance of common stock for cash	2,989,655	$ 2,989	$ 10,629,802			$ 10,632,791
Issuance of common stock for services	450,180	$ 451	$ 933,977			$ 934,428
Issuance of common stock - mineral interests	1,781,595	$ 1,782	$ 5,135,097			$ 5,136,879
Issuance of common stock in warrant exercise	617,500	$ 618	$ 1,276,882			$ 1,277,500
Issuance of common stock for note interest	5,869	$ 5	$ 10,265			$ 10,270
Warrants issued with promissory notes			$ 562,354		$ 72,000	$ 634,354
Warrants issued in private placement	0		$ 123,250		$ (116,700)	$ 6,550
Warrants issued for services	0		$ 78,765			$ 78,765
Common stock issued in conversion of notes	1,248,877	$ 1,248	$ 2,184,287			$ 2,185,535
Beneficial conversion feature on conv. notes			$ 195,466			$ 195,466
Warrants issued for services					$ 4,637,600	$ 4,637,600
Net loss				$ (15,809,603)		$ (15,809,603)
Balance, December 31, 2014	23,235,441	$ 23,235	$ 43,108,752	$ (31,650,561)	$ 7,636,320	$ 19,117,745

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

TORCHLIGHT ENERGY RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOW

	YEAR ENDED December 31, 2014	YEAR ENDED December 31, 2013
Cash Flows From Operating Activities		
Net (loss)	$ (15,809,603)	$ (10,418,662)
Adjustments to reconcile net loss to net cash from operations:		
Stock based compensation	5,644,028	4,331,143
Accretion of convertible note discounts	5,771,050	3,894,389
Income - Cancellation of Debt	(22,748)	(660,000)
Impairment expense	447,084	-
Depreciation, depletion and amortization	2,736,562	652,179
Change in:		
Accounts receivable	133,851	(336,803)
Note receivable	(515,748)	-
Production revenue receivable	(210,435)	-
Prepayment of development costs	(20,602)	-
Prepaid expenses	(20,490)	(798)
Debt isssuance costs	(185,875)	(967,020)
Other assets	(3,506)	(74,379)
Accounts payable and accrued liabilities	3,180,467	833,820
Related party payable	-	(18,648)
Due to working interest owners	(507,045)	255,484
Asset retirement obligation	11,170	1,360
Interest payable	84,513	245,299
Capitalized interest	(371,116)	-
Net cash provided by (used) in operating activities	341,557	(2,262,636)
Cash Flows From Investing Activities		
Investment in oil and gas properties	(18,591,329)	(9,663,504)
Acquisition of office equipment	(53,960)	-
Proceeds from Sale of Leases	-	1,076,400
Net cash used in investing activities	(18,645,289)	(8,587,104)
Cash Flows From Financing Activities		
Proceeds from sale of common stock	10,632,791	850,000
Proceeds from issuance of convertible notes	4,569,500	10,855,773
Proceeds from warrant exercise	744,282	203,428
Proceeds from promissory notes	815,491	750,000
Repayment of promissory notes	(90,258)	(61,000)
Net cash provided by financing activities	16,671,806	12,598,201
Net increase (decrease) in cash	(1,631,926)	1,748,461
Cash - beginning of period	1,811,713	63,252
Cash - end of period	$ 179,787	$ 1,811,713
Supplemental disclosure of cash flow information:		
Non cash transactions:		
Common stock issued for services	$ 933,977	$ -
Warrants issued in connection with promissory notes	$ 634,354	$ 2,531,321
Warrants issued for services	$ 4,716,365	$ -
Beneficial conversion feature on promissory notes	$ 195,466	$ 5,770,654
Liabilitities assumed-purchase of properties	$ -	$ 1,809,572
Promissory note issued for debt issuance	$ -	40,000
Sale of properties for note receivable	$ -	$ 990,000
Common stock issued for mineral interests	$ 5,136,879	$ 1,233,967
Capitalized interest cost	$ 371,116	$ 56,347
Common stock issued in connection with promissory notes	$ 2,185,535	$ 1,695,100
Common stock issued in warrant exercises	$ 1,277,500	$ -
Asset retirement obligation	$ 11,170	$ 10,407
Cash paid for interest	$ 1,243,816	$ 468,841

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. NATURE OF BUSINESS

Torchlight Energy Resources, Inc. was incorporated in October 2007 under the laws of the State of Nevada as Pole Perfect Studios, Inc. ("PPS"). From its incorporation to November 2010, the company was primarily engaged in business start-up activities.

On November 23, 2010, we entered into and closed a Share Exchange Agreement (the "Exchange Agreement") between the major shareholders of PPS and the shareholders of Torchlight Energy, Inc. ("TEI"). As a result of the transactions effected by the Exchange Agreement, at closing TEI became our wholly-owned subsidiary, and the business of TEI became our sole business. TEI was incorporated under the laws of the State of Nevada in June 2010. We are engaged in the acquisition, exploitation and/or development of oil and natural gas properties in the United States. In addition to TEI, we also operate our business through Torchlight Energy Operating, LLC, a Texas limited liability company and wholly-owned subsidiary.

On December 10, 2010, we effected a 4-for-1 forward split of our shares of common stock outstanding. All owners of record at the close of business on December 10, 2010 (record date) received three additional shares for every one share they owned. All share amounts reflected throughout this report take into account the 4-for-1 forward split.

Effective February 8, 2011, we changed our name to "Torchlight Energy Resources, Inc." In connection with the name change, our ticker symbol changed from "PPFT" to "TRCH."

The Company is engaged in the acquisition, exploration, development and production of oil and gas properties within the United States. The Company's success will depend in large part on its ability to obtain and develop profitable oil and gas interests.

2. GOING CONCERN

These consolidated financial statements have been prepared in accordance with generally accepted accounting principles applicable to a going concern, which assumes that the Company will be able to meet its obligations and continue its operations for its next fiscal year.

At December 31, 2014, the Company had not yet achieved profitable operations. We had a net loss of approximately $15.8 million for the year ended December 31, 2014 and had accumulated losses of $31,650,561 since its inception and expects to incur further losses in the development of its business. Working Capital as of December 31, 2014 was negative $11,873,048 including the March 31, 2015 maturity of our Series A Secured Convertible Notes. The Company's ability to continue as a going concern is dependent on its ability to generate future profitable operations and/or to obtain the necessary financing to meet its obligations and repay its liabilities arising from normal business operations when they come due. Management's plan to address the Company's ability to continue as a going concern includes: (1) obtaining debt or equity funding from private placement or institutional sources; (2) obtain loans from financial institutions, where possible, or (3) participating in joint venture transactions with third parties. Although management believes that it will be able to obtain the necessary funding to allow the Company to remain a going concern through the methods discussed above, there can be no assurances that such methods will prove successful. The accompanying consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

On March 31, 2015, the maturity date for our issued and outstanding 12% Series A Secured Convertible Promissory Notes ("Series A Notes") occurred, and we did not make any payment to these note holders of the principal and interest due thereunder. This is an event of default under the terms and conditions of the Series A Notes, and the Agent for the Series A Note holders may exercise on behalf of such holders all rights and remedies available under the terms and conditions of the Series A Notes or applicable laws.

Additionally, our default in payment of the Series A Notes triggered a cross-default provision in our 12% Series B Convertible Unsecured Promissory Notes ("Series B Notes"), and any holder of a Series B Note may declare any an all of the obligations under such note due and payable and/or exercise any other rights and remedies available to such holder under the terms and conditions of the Series B Notes.

Planned Divestiture of Hunton Project

On April 8, 2015, management announced that they are seeking to divest certain of our Hunton assets located in Logan and Kingfisher Counties, Oklahoma. The Company is actively marketing these assets to potential buyers. These assets include lease rights and current production, which are being marketed separately. There has been discussions with interested parties and management expects to have a buyer identified shortly. The proceeds from a sale of all or a portion of the assets will be used to satisfy obligations to our Series A Note holders.

3. SIGNIFICANT ACCOUNTING POLICIES

The Company maintains its accounts on the accrual method of accounting in accordance with accounting principles generally accepted in the United States of America. Accounting principles followed and the methods of applying those principles, which materially affect the determination of financial position, results of operations and cash flows are summarized below:

Use of estimates – The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and certain assumptions that affect the amounts reported in these consolidated financial statements and accompanying notes. Actual results could differ from these estimates.

Basis of presentation—The financial statements are presented on a consolidated basis and include all of the accounts of Torchlight Energy Resources Inc. and its wholly owned subsidiary, Torchlight Energy, Inc. All significant intercompany balances and transactions have been eliminated.

3. SIGNIFICANT ACCOUNTING POLICIES - *continued*

Risks and uncertainties – The Company's operations are subject to significant risks and uncertainties, including financial, operational, technological, and other risks associated with operating an emerging business, including the potential risk of business failure.

Concentration of risks – The Company's cash is placed with a highly rated financial institution, and the Company periodically reviews the credit worthiness of the financial institutions with which it does business. At times the Company's cash balances are in excess of amounts guaranteed by the Federal Deposit Insurance Corporation.

Fair value of financial instruments – Financial instruments consist of cash, accounts receivable, accounts payable, notes payable to related party, and convertible promissory notes. The estimated fair values of cash, accounts receivable, accounts payable, and related party payables approximate the carrying amount due to the relatively short maturity of these instruments. The carrying amounts of the convertible promissory notes approximate their fair value giving affect for the term of the note and the effective interest rates.

For assets and liabilities that require re-measurement to fair value the Company categorizes them in a three-level fair value hierarchy as follows:

- Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities.
- Level 2 inputs are quoted prices for similar assets and liabilities in active markets or inputs that are observable for the asset or liability, either directly or indirectly through market corroboration.
- Level 3 inputs are unobservable inputs based on management's own assumptions used to measure assets and liabilities at fair value.

A financial asset or liability's classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement.

Accounts receivable – Accounts receivable consist of uncollateralized oil and natural gas revenues due under normal trade terms, as well as amounts due from working interest owners of oil and gas properties for their share of expenses paid on their behalf by the Company. Management reviews receivables periodically and reduces the carrying amount by a valuation allowance that reflects management's best estimate of the amount that may not be collectible. As of December 31, 2014 and December 31, 2013 no valuation allowance was considered necessary.

Investment in oil and gas properties – The Company uses the full cost method of accounting for exploration and development activities as defined by the Securities and Exchange Commission ("SEC"). Under this method of accounting, the costs of unsuccessful, as well as successful, exploration and development activities are capitalized as properties and equipment. This includes any internal costs that are directly related to property acquisition, exploration and development activities but does not include any costs related to production, general corporate overhead or similar activities. Gain or loss on the sale or other disposition of oil and gas properties is not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves.

Oil and gas properties include costs that are excluded from costs being depleted or amortized. Oil and natural gas property costs excluded represent investments in unevaluated properties and include non-producing leasehold, geological, and geophysical costs associated with leasehold or drilling interests and exploration drilling costs. The Company allocates a portion of its acquisition costs to unevaluated properties based on relative value. Costs are transferred to the full cost pool as the properties are evaluated over the life of the reservoir.

Capitalized interest – The Company capitalizes interest on unevaluated properties during the periods in which they are excluded from costs being depleted or amortized. During years ended December 31, 2014 and 2013, the Company capitalized $371,116 and $104,821, respectively, of interest on unevaluated properties.

Depreciation, depletion, and amortization – The depreciable base for oil and natural gas properties includes the sum of all capitalized costs net of accumulated depreciation, depletion, and amortization ("DD&A"), estimated future development costs and asset retirement costs not included in oil and natural gas properties, less costs excluded from amortization. The depreciable base of oil and natural gas properties is amortized on a unit-of-production method.

3. SIGNIFICANT ACCOUNTING POLICIES - *continued*

Ceiling test – Future production volumes from oil and gas properties are a significant factor in determining the full cost ceiling limitation of capitalized costs. Under the full cost method of accounting, the Company is required to periodically perform a “ceiling test” that determines a limit on the book value of oil and gas properties. If the net capitalized cost of proved oil and gas properties, net of related deferred income taxes, plus the cost of unproved oil and gas properties, exceeds the present value of estimated future net cash flows discounted at 10 percent, net of related tax affects, plus the cost of unproved oil and gas properties, the excess is charged to expense and reflected as additional accumulated DD&A. The ceiling test calculation uses a commodity price assumption which is based on the un weighted arithmetic average of the price on the first day of each month for each month within the prior 12 month period and excludes future cash outflows related to estimated abandonment costs. The Company did not recognize impairment on its oil and gas properties during the years ended December 31, 2014 and 2013. Due to the volatility of commodity prices, should oil and natural gas prices decline in the future, it is possible that a write-down could occur. Proved reserves are estimated quantities of crude oil, natural gas, and natural gas liquids, which geological and engineering data demonstrate with reasonable certainty to be recoverable from known reservoirs under existing economic and operating conditions. The independent engineering estimates include only those amounts considered to be proved reserves and do not include additional amounts which may result from new discoveries in the future, or from application of secondary and tertiary recovery processes where facilities are not in place or for which transportation and/or marketing contracts are not in place. Estimated reserves to be developed through secondary or tertiary recovery processes are classified as unevaluated properties.

The determination of oil and gas reserves is a subjective process, and the accuracy of any reserve estimate depends on the quality of available data and the application of engineering and geological interpretation and judgment. Estimates of economically recoverable reserves and future net cash flows depend on a number of variable factors and assumptions that are difficult to predict and may vary considerably from actual results. In particular, reserve estimates for wells with limited or no production history are less reliable than those based on actual production. Subsequent re-evaluation of reserves and cost estimates related to future development of proved oil and gas reserves could result in significant revisions to proved reserves. Other issues, such as changes in regulatory requirements, technological advances, and other factors which are difficult to predict could also affect estimates of proved reserves in the future.

Gains and losses on the sale of oil and gas properties are not generally reflected in income. Sales of less than 100% of the Company’s interest in the oil and gas property are treated as a reduction of the capital cost of the field, with no gain or loss recognized, as long as doing so does not significantly affect the unit-of-production depletion rate. Costs of retired equipment, net of salvage value, are usually charged to accumulated depreciation.

Goodwill – Goodwill represents the excess of the purchase price over the fair value of the net identifiable tangible and intangible assets of acquired companies. Goodwill is not amortized; instead, it is tested for impairment annually or more frequently if indicators of impairment exist.

Goodwill was $447,084 as of December 31, 2013 and was acquired on November 23, 2010 in connection with the Company’s reverse acquisition (Note 1). The Goodwill was tested for impairment at December 31, 2014 by comparison of the fair value of the Company measured by its market cap versus its book value and as a result was written off to Impairment expense.

Asset retirement obligations – Accounting principles require that the fair value of a liability for an asset’s retirement obligation (“ARO”) be recorded in the period in which it is incurred if a reasonable estimate of fair value can be made, and that the corresponding cost be capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its then-present value each subsequent period, and the capitalized cost is depleted over the useful life of the related asset. Abandonment cost incurred is recorded as a reduction to the ARO liability.

Inherent in the fair value calculation of an ARO are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental, and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the oil and gas property balance. Settlements greater than or less than amounts accrued as ARO are recorded as a gain or loss upon settlement.

Asset retirement obligation activity is disclosed in Note 10.

Share-based compensation – Compensation cost for equity awards is based on the fair value of the equity instrument on the date of grant and is recognized over the period during which an employee is required to provide service in exchange for the award. Compensation cost for liability awards is based on the fair value of the vested award at the end of each period.

Revenue recognition – The Company recognizes oil and gas revenues when production is sold at a fixed or determinable price, persuasive evidence of an arrangement exists, delivery has occurred and title has transferred, and collectability is reasonably assured.

3. SIGNIFICANT ACCOUNTING POLICIES - *continued*

Basic and diluted earnings (loss) per share – Basic earnings (loss) per common share is computed by dividing net income (loss) available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings (loss) per common share is computed in the same way as basic earnings (loss) per common share except that the denominator is increased to include the number of additional common shares that would be outstanding if all potential common shares had been issued and if the additional common shares were dilutive. The Company has not included potentially dilutive securities in the calculation of loss per share for any periods presented as the effects would be anti-dilutive.

Environmental laws and regulations – The Company is subject to extensive federal, state, and local environmental laws and regulations. Environmental expenditures are expensed or capitalized depending on their future economic benefit. The Company believes that it is in compliance with existing laws and regulations.

Recent accounting pronouncements –

On August 27, 2014, the FASB issued ASU 2014-15, which provides guidance on determining when and how to disclose going-concern uncertainties in the financial statements. The new standard requires management to perform interim and annual assessments of the Company's ability to continue as a going concern within one year of the date the financial statements are issued. An entity must provide certain disclosures if conditions or events raise substantial doubt about the entity's ability to continue as a going concern. The ASU applies to all entities and is effective for annual periods ending after December 15, 2016, and interim periods thereafter, with early adoption permitted.

In May 2014, the FASB issued ASU 2014-09 that introduces a new five-step revenue recognition model in which an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This ASU also requires disclosures sufficient to enable users to understand the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers, including qualitative and quantitative disclosures about contracts with customers, significant judgments and changes in judgments, and assets recognized from the costs to obtain or fulfill a contract. This standard is effective for fiscal years beginning after December 15, 2017, including interim periods within that reporting period. The Company is currently evaluating the new guidance to determine the impact it will have on its consolidated financial statements.

In April 2014, the FASB issued ASU 2014-08, which includes amendments that change the requirements for reporting discontinued operations and require additional disclosures about discontinued operations. Under the new guidance, only disposals representing a strategic shift in operations - that is, a major effect on the organization's operations and financial results should be presented as discontinued operations. Additionally, the ASU requires expanded disclosures about discontinued operations that will provide financial statement users with more information about the assets, liabilities, income, and expenses of discontinued operations. The new standard is effective in the first quarter of 2015 for public organizations with calendar year ends. Early adoption would be permitted for any annual or interim period for which an entity's financial statements have not yet been made available for issuance. The adoption of this guidance is not expected to have an impact on the Company's consolidated financial statements.

Other recently issued or adopted accounting pronouncements are not expected to have, or did not have, a material impact on the Company's financial position or results from operations.

Subsequent events **–** The Company evaluated subsequent events through April 15, 2015, the date of issuance of the financial statements. Subsequent events are disclosed in Note 11.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

4. RELATED PARTY PAYABLES

As of December 31, 2014, related party payables consisted of accrued and unpaid compensation to two of our executive officers totaling $90,000. The related party payables at December 31, 2012 included $660,000 of accrued compensation due to our executive officers and directors. The officers forgave the $660,000 of related party debt during third quarter, 2013.

A Director and a principal shareholder have advanced funds to the Company as short term loans totaling $607,808 as of December 31, 2014.

5. COMMITMENTS AND CONTINGENCIES

The Company is subject to contingencies as a result of environmental laws and regulations. Present and future environmental laws and regulations applicable to the Company's operations could require substantial capital expenditures or could adversely affect its operations in other ways that cannot be predicted at this time. As of December 31, 2014 and 2013, no amounts had been recorded because no specific liability has been identified that is reasonably probable of requiring the Company to fund any future material amounts.

6. STOCKHOLDERS' EQUITY

During the years ended December 31, 2014 and 2013, the Company issued 450,180 and 735,752 shares of common stock, respectively, as compensation for services, with total values of $934,428 and $1,438,977.

During the years ended December 31, 2014 and 2013, the Company issued 1,847,500 and 2,403,174 warrants, respectively, as compensation for services, with a total values of $4,637,600 and $2,920,170.

During the year ended December 31, 2014 and 2013, the Company issued -0- and 1,308,124 warrants, respectively, in connection with financing transactions discussed in Note 9, including -0- and 552,057 warrants issued to the placement agent.

During the year ended December 31, 2014 and 2013, the Company issued 1,781,595 and 558,356 shares of Common Stock, respectively, as acquisition of lease interests valued at $5,136,879 and $1,233,967.

During the year ended December 31, 2014 and 2013 the Company issued 1,248,877 and 968,628 shares of Common Stock, respectively, in conversions of 12% Convertible Notes Payable valued at $2,185,535 and $1,695,100.

During the year ended December 31, 2014 and 2013 the Company issued 623,369 and 101,714 shares of Common Stock, respectively, resulting from Warrant exercises for consideration totaling $1,287,770 and $203,428.

6. STOCKHOLDERS' EQUITY - *continued*

During December 2013 and early January 2014, we sold to investors in a private offering an aggregate of 350,000 shares of restricted common stock and 87,500 warrants to purchase shares of restricted common stock. Each warrant has an exercise price of $6.00 per share and expires on December 31, 2018. We received aggregate consideration of $1,400,000 for the securities, $850,000 in December and $550,000 in January, 2014.

A summary of stock options and warrants outstanding as of December 31, 2014 by exercise price and year of expiration is presented below:

Exercise Price	Expiration Date In 2,015	2,016	2,017	2,018	2,019	Total
$ 1.00	0	0	150,000	0	0	150,000
$ 1.75	855,000	1,135,714	0	0		1,990,714
$ 2.00	0	1,035,271	126,000	1,696,380		2,857,651
$ 2.09				2,800,000		2,800,000
$ 2.50	15,000	100,000	0	0		115,000
$ 2.75		0				0
$ 2.82				38,174		38,174
$ 3.00		100,000				100,000
$ 4.50					700,000	700,000
$ 5.00	0	8,391	95,000			103,391
$ 6.00				577,501	330,341	907,842
$ 7.00					700,000	700,000
	870,000	2,379,376	371,000	5,112,055	1,730,341	10,462,772

As of the date of this filing, 165,000 of the warrants exercisable in 2015 have expired.

At December 31, 2014 the Company had reserved 10,462,772 shares for future exercise of warrants.

Warrants issued in relation to the promissory notes issued (see note 9) were valued using the Black Scholes Option Pricing Model. The assumptions used in calculating the fair value of the warrants issued are as follows:

Risk-free interest rate	0.78%
Expected volatility of common stock	191% - 253%
Dividend yield	0.00%
Discount due to lack of marketability	20-30%
Expected life of warrant	3 years - 5 years

7. CAPITALIZED COSTS

The following table presents the capitalized costs of the Company as of December 31, 2014 and December 31, 2013:

	2014	2013
Evaluated costs subject to amortization	$ 24,276,483	$ 9,484,014
Unevaluated costs	14,152,415	4,758,806
Total capitalized costs	38,428,898	14,242,820
Less accumulated depreciation, depletion and amortization	(3,930,217)	(1,204,069)
Net capitalized costs	$ 34,498,681	$ 13,038,751

Unevaluated costs as of December 31, 2014 consisted of $710,139 associated with the Company's interest in the Coulter #1 well. The Coulter is a non-core, non-producing asset which we will attempt to monetize by sale of the lease. We presently have approximately 940 acres.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

8. INCOME TAXES

Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss carry forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized. The Company has placed a 100% valuation allowance against the net deferred tax asset because future realization of these assets is not assured.

Authoritative guidance for uncertainty in income taxes requires that the Company recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an examination. Management has reviewed the Company's tax positions and determined there were no uncertain tax positions requiring recognition in the consolidated financial statements. The Company's tax returns remain subject to Federal and State tax examinations for all tax years since inception as none of the statutes have expired. Generally, the applicable statutes of limitation are three to four years from their respective filings.

Estimated interest and penalties related to potential underpayment on any unrecognized tax benefits are classified as a component of tax expense in the statement of operation. The Company has not recorded any interest or penalties associated with unrecognized tax benefits for any periods covered by these financial statements.

The following is a reconciliation between the federal income tax benefit computed at the statutory federal income tax rate of 34% and actual income tax provision for the years ended December 31, 2014 and December 31, 2013:

	Year ended Dec. 31, 2014	Year ended Dec. 31, 2013
Federal income tax benefit at statutory rate	$ (5,626,540)	$ (3,542,345)
Permanent Differences	511,184	696,631
Other	894,181	(470,413)
Change in valuation allowance	4,221,175	3,316,127
Provision for income taxes	$ -	$ -

The tax effects of temporary differences that gave rise to significant portions of deferred tax assets and liabilities at December 31, 2014 and December 31, 2013 are as follows:

	Dec. 31, 2014	Dec. 31, 2013
Deferred tax assets:		
Net operating loss carryforward	$ 8,190,580	$ 4,229,034
Accruals	30,600	30,600
Reserves	2,952,364	1,132,778
Deferred tax liabilities:		
Intangible drilling and other costs for oil and gas properties	(1,865,259)	(318,039)
Net deferred tax assets and liabilities	9,308,285	5,074,373
Less valuation allowance	(9,308,285)	(5,074,373)
Total deferred tax assets and liabilities	$ -	$ -

The Company had a net deferred tax asset related to federal net operating loss carry forwards of $8,190,580 and $4,229,034 at December 31, 2014 and December 31, 2013, respectively. The federal net operating loss carry forward will begin to expire in 2030. Realization of the deferred tax asset is dependent, in part, on generating sufficient taxable income prior to expiration of the loss carry forwards. The Company has placed a 100% valuation allowance against the net deferred tax asset because future realization of these assets is not assured.

9. PROMISSORY NOTES

On December 18, 2012, the Company exchanged $412,500 of outstanding convertible promissory notes for new 12% Series A Secured Convertible Promissory Notes ("12% Notes") described below. The 12% Notes were issued as part of a larger offering with senior liens on the Company's oil and gas properties. In order to induce the holders of the previously outstanding convertible promissory notes to exchange such promissory notes and to relinquish their priority liens on the Company's oil and gas properties in favor of all 12% Convertible Promissory Note Holders, the Company agreed to grant the note holders a total of 235,714 four year warrants to purchase common stock at $1.75 per share, valued at $240,428, and 235,714 four year warrants to purchase common stock at $2.00 per share, valued at $233,357. The total of these warrants, $473,785, is reflected as debt issuance costs on the balance sheet as of December 31, 2012, as these costs relate to the larger offering of 12% Convertible Promissory Notes.

On December 18, 2012, the Company issued $690,000 of 12% Notes to new investors. Together with the conversion described above, there was $1,102,500 of principal amount outstanding as of December 31, 2012. The 12% Notes are due and payable on March 31, 2015 and provide for conversion into common stock at a price of $1.75 per share and include the issuance of 8,000 warrants for each $70,000 of principal amount purchase. The warrants carry a five year term and have an exercise price of $2.00 per share. They were valued at $137,340, which is reflected as a discount on the 12% Notes, to be amortized over the life of the debt under the effective interest method. Since the conversion price on the 12% Notes was below the market price of the Company's common stock on the date of issuance, this constitutes a beneficial conversion feature. The amount is calculated as the difference between the market price of the common stock on the date of closing and the effective conversion price as adjusted by the discount for the warrants issued. The amount of the beneficial conversion feature was $390,600, and is also reflected as a discount on the 12% Notes. The fair value of the Convertible Promissory Notes is determined utilizing Level 2 measurements in the fair value hierarchy.

During the year ended December 31, 2013, the Company issued an additional $10,895,773 in principal value of 12% Notes. Such notes carry the same terms as described above. In connection therewith, the Company also issued a total of 1,308,082 five-year warrants to purchase common stock at an exercise price of $2.00 per share. The value of the warrant shares was $1,917,158 and the amount recorded for the beneficial conversion feature was $5,770,654. These amounts were recorded as a discount on the 12% Notes. In addition, the Company engaged a placement agent to source investors for the majority of these additional notes. This placement agent was paid a fee of 10% of the principal amount of the notes plus a non-accountable expense reimbursement of up to 2% of the principal raised by the agent. The placement agent also received 552,057 warrants to purchase common shares at $2.00 per share for a period of three years, valued at $614,163. All the amounts paid to the placement agent have been included in debt issuance costs and will be amortized into interest expense over the life of the 12% Notes.

The 12% Notes have a first priority lien on all of the assets of the Company.

The Series "A" Convertible Notes total outstanding principal balance of $8,117,598 plus interest, was due in full at their maturity date of March 31, 2015. As of the date of this filing, the principal and interest are unpaid resulting in the Company being in default.

During the quarter ended June 30, 2014, the Company issued an additional $3,197,500 in principal value of 12% Series B Convertible Unsecured Promissory Notes. The 12% Notes are due and payable on June 30, 2017 and provide for conversion into common stock at a price of $4.50 per share and included the issuance of one warrant for each $22.50 of principal amount purchased. The Company issued a total of 142,111 of these five-year warrants to purchase common stock at an exercise price of $6.00 per share. The value of the warrant shares was $405,016 and the amount recorded for the beneficial conversion feature was $195,466. These amounts were recorded as a discount on the 12% Notes.

During the quarter ended September 30, 2014, the Company issued an additional $1,372,000 in principal value of 12% Series B Convertible Unsecured Promissory Notes. The 12% Notes are due and payable on June 30, 2017 and provide for conversion into common stock at a price of $4.50 per share and included the issuance of one warrant for each $22.50 of principal amount purchased. The Company issued a total of 60,974 of these five-year warrants to purchase common stock at an exercise price of $6.00 per share. The value of the warrant shares was $157,388 and the amount recorded for the beneficial conversion feature was $-0-. These amounts were recorded as a discount on the 12% Notes.

As of the date of this filing, we have not made the interest payment due to Series B Note holders on March 31, 2015.

The Company is obligated on a short term note payable for $221,910 as of December 31, 2014 which was due December 12, 2014 with 10% interest.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

10. ASSET RETIREMENT OBLIGATIONS

The following is a reconciliation of the asset retirement obligation liability through December 31, 2014:

Asset retirement obligation – December 31, 2012	$	12,614
Estimated liabilities recorded		10,407
Accretion Expense		1,361
Asset retirement obligation – December 31, 2013	$	24,382
Estimated liabilities recorded		7,789
Accretion Expense		3,780
Asset retirement obligation – December 31, 2014	$	35,951

11. SUBSEQUENT EVENTS

Promissory Notes

On March 31, 2015, the maturity date for our issued and outstanding 12% Series A Secured Convertible Promissory Notes ("Series A Notes") occurred, and we did not make any payment to these note holders of the principal and interest due thereunder. This is an event of default under the terms and conditions of the Series A Notes, and the Agent for the Series A Note holders may exercise on behalf of such holders all rights and remedies available under the terms and conditions of the Series A Notes or applicable laws. All obligations under the Series A Notes will bear interest at a default rate of 18% per annum until such time that they are paid in full. The total principal amount outstanding on the Series A Notes is $8,117,598, exclusive of interest. We are having ongoing discussions with the Agent regarding various possible solutions for the payment of this obligation.

Additionally, our default in payment of the Series A Notes triggered a cross-default provision in our 12% Series B Convertible Unsecured Promissory Notes ("Series B Notes"), and any holder of a Series B Note may declare any an all of the obligations under such note due and payable and/or exercise any other rights and remedies available to such holder under the terms and conditions of the Series B Notes. All obligations under the Series B Notes will bear interest at a default rate of 16% per annum. We have not made the interest payment due to Series B Note holders on March 31, 2015. The total principal amount outstanding on the Series B Notes is $4,569,500, exclusive of interest.

Planned Divestiture of Hunton Project

On April 8, 2015, we announced that we are seeking to divest certain of our Hunton assets located in Logan and Kingfisher Counties, Oklahoma. We are actively marketing these assets to potential buyers. These assets include lease rights and current production, which are being marketed separately. We have been in discussions with interested parties and expect to have a buyer identified shortly. The proceeds from a sale of all or a portion of the assets will be used to satisfy obligations to our Series A Note holders.

Restructure of JIB with Husky Ventures

During February, 2015, the Company entered into an agreement with Husky Ventures Inc. to restructure the amounts due under Husky's Joint Interest Billing ("JIB") to the Company. During the fourth quarter, 2014, Husky presented a series of cash calls to the Company for participation in drilling projects in Oklahoma. The Company did not fund the prepayments requested. However, as drilling began, Husky carried the Company's share of development expenses on the JIB account. It was determined in the first quarter, 2015 that the Company would be unable to fund the requested prepayments and an agreement was reached to reverse the development cost charges on the JIB in exchange for Torchlight relinquishing any claims that it might have had for an interest in the fourteen wells covered by the agreement. The adjustments to account for the reversal were made effective December 31, 2014. No development cost, revenue, or operating expenses with respect to those wells have been recorded in the records of the Company as of December 31, 2014 since the Company did not pay for any participation in those wells.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

UNAUDITED SUPPLEMENTARY INFORMATION

December 31, 2014 and 2013

Investment in oil and gas properties for 2014 is detailed as follows:

	2014	2013
Property acquisition costs	$ 7,222,793	$ 6,274,154
Development costs	11,368,536	3,885,730
Exploratory costs	$ -0-	$ -0-

Oil and Natural Gas Reserves

Reserve Estimates

SEC Case. The following tables sets forth, as of December 31, 2014, our estimated net proved oil and natural gas reserves, the estimated present value (discounted at an annual rate of 10%) of estimated future net revenues before future income taxes (PV-10) and after future income taxes (Standardized Measure) of our proved reserves and our estimated net probable oil and natural gas reserves, each prepared using standard geological and engineering methods generally accepted by the petroleum industry and in accordance with assumptions prescribed by the Securities and Exchange Commission ("SEC"). All of our reserves are located in the United States.

The PV-10 value is a widely used measure of value of oil and natural gas assets and represents a pre-tax present value of estimated cash flows discounted at ten percent. PV-10 is considered a non-GAAP financial measure as defined by the SEC. We believe that our PV-10 presentation is relevant and useful to our investors because it presents the estimated discounted future net cash flows attributable to our proved reserves before taking into account the related future income taxes, as such taxes may differ among various companies. We believe investors and creditors use PV-10 as a basis for comparison of the relative size and value of our proved reserves to the reserve estimates of other companies. PV-10 is not a measure of financial or operating performance under GAAP and neither it nor the Standardized Measure is intended to represent the current market value of our estimated oil and natural gas reserves. PV-10 should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP.

Our PV-10 at December 31, 2014 and 2013 is materially reconciled to our Standardized Measure of discounted cash flows at those dates by reducing the PV-10 by the discounted future income taxes associated with such reserves. The discounted future income taxes at December 31, 2014 and 2013, respectively, were $678,904 and $7,093,985.

The estimates of our proved reserves and the PV-10 set forth herein reflect estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs under existing economic conditions at December 31, 2014. For purposes of determining prices, we used the average of prices received for each month within the 12-month period ended December 31, 2014, adjusted for quality and location differences, which was $91.48 per barrel of oil and $4.35 per MCF of gas. This average historical price is not a prediction of future prices. The amounts shown do not give effect to non-property related expenses, such as corporate general administrative expenses and debt service, future income taxes or to depreciation, depletion and amortization.

UNAUDITED SUPPLEMENTARY INFORMATION - *continued*

	December 31, 2014 Reserves			December 31, 2014 Future Net Revenue (M$)	
Category	Oil (Bbls)	Gas (Mcf)	Total (BOE)	Total	Present Value Discounted at 10%
Proved Developed	120,000	687,000	234,500	$ 9,909	$ 7,670
Proved Undeveloped	794,400	3,104,000	1,311,733	$ 32,585	$ 16,026
Total Proved	914,400	3,791,000	1,546,233	42,494	23,696
Standardized Measure of Future Net Cash Flows Related to Proved Oil and Gas Properties					$ 23,019
Probable Undeveloped	912.400	0	912,400	$ 22,779	$ 8,558

	December 31, 2013 Reserves			December 31, 2013 Future Net Revenue (M$)	
Category	Oil (Bbls)	Gas (Mcf)	Total (BOE)	Total	Present Value Discounted at 10%
Proved Developed	113,092	313,251	165,301	$ 8,861	$ 6,117
Proved Undeveloped	930,069	2,826,344	1,401,126	$ 44,699	$ 20,408
Total Proved	1,043,161	3,139,595	1,566,427	$ 53,560	$ 26,525
Standardized Measure of Future Net Cash Flows Related to Proved Oil and Gas Properties					$ 19,691
Probable Undeveloped	657,800	0	657,800	$ 33,571	$ 16,253

BOE equivalents are determined by combining barrels of oil with MCF of gas divided by six.

The decrease of 89,393 BOE (89,285 for our Hunton Project and 108 for our Marcelina Project) in proved undeveloped reserves comes from the third party engineering studies of the Cimarron and Chisholm Trail AMI's in Oklahoma which were acquired by the Company in 2013 and engineering studies for our Marcelina Project.

No reserve value for the Ring Project is included in 2014 reserve tables presented above since the company believes this project is still considered to be in the testing phase.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

UNAUDITED SUPPLEMENTARY INFORMATION - *continued*

Standardized Measure of Oil & Gas Quantities - Volume Rollforward
Years Ended December 31, 2014 and 2013

The following table sets forth the Company's net proved reserves, including the changes therein, and proved developed reserves:

	2014		2013	
	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)
TOTAL PROVED RESERVES:				
Beginning of period	1,043,161	3,139,594	417,549	-
Acquisition	-	-	572,461	3,139,595
Extensions and discoveries	312,579	-	101,180	-
Revisions of previous estimates	(388,485)	821,150	(34,743)	3,539
Production	(52,855)	(170,094)	(13,286)	(3,540)
End of period	914,400	3,790,650	1,043,161	3,139,594
PROVED DEVELOPED RESERVES				
Proved developed producing	102,479	488,410	64,858	108,001
Proved developed nonproducing	17,521	198,710	48,234	205,250
Total	120,000	687,120	113,092	313,251
Total PUD	794,400	3,103,530	930,069	2,826,344

The preceding table shows significant decrease in the Acquisition category for 2014 as compared to 2013. The 2013 Acquisition increase is all related to the working interest acquired in the Cimarron and the Chisholm Trail AMI's with Husky Ventures in Oklahoma during 2013. During 2014 the company focused on expanding its participation in the Chisholm Trail and Cimarron AMI'S in Oklahoma which accounts for the increase in Extensions and Discoveries for 2014.

The 2013 Revisions of Previous Estimates are composed of revisions to the proved producing and proved undeveloped reserves.

The downward revision of 388,485 BO results primarily from eliminating two Eagle Ford wells (which are now considered uneconomic at current prices) from reserve report calculations for the Company's properties in the Marcelina Creek Project in Texas. This reflects a reduction of 366,366 BO offset directly by an increase in reserves of 60,159 BO from the currently producing wells. The Johnson #1 is the largest contributor, with an increase of reserves of 56,783 BO. The Johnson #2 and #4 account for an additional increase of 3,376 BO. The remaining difference comes from reserve adjustments in the well data for the Oklahoma Properties reserve calculations for 2014.

The positive revision of 821,150 MCF of gas is attributable to gas production increase from the development activity in the Chisholm Trail and Cimarron AMI's in Oklahoma where the Company focused on expanding its participation in 2014 drilling and development. Gas reserves can be fully attributable to our Oklahoma joint venture operations. Most of our wells in the program are horizontally drilled wells that produce from the Hunton rock which requires a fracking stimulation to achieve the maximum production rates. Typically these wells have a relatively high initial production rates, but decline rapidly. Three wells in our Oklahoma ventures contribute 244.8 MMcf of the total improvement. As a result of the PDP wells success the offsetting PUD wells are expected to be significant contributors as well. Our other producing wells in Oklahoma are evenly spread.

UNAUDITED SUPPLEMENTARY INFORMATION - *continued*

Standardized Measure of Oil & Gas Quantities
Year Ended December 31, 2014 & 2013

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves is as follows :	2014	2013
Future cash inflows	$ 106,027,440	$ 119,629,906
Future production costs	(30,383,390)	(31,656,853)
Future development costs	(33,148,780)	(34,152,898)
Future income tax expense	(978,776)	(11,264,101)
Future net cash flows	41,516,494	42,556,054
10% annual discount for estimated timing of cash flows	(18,497,528)	(22,865,456)
Standardized measure of discounted future net cash flows related to proved reserves	$ 23,018,966	$ 19,690,598

A summary of the changes in the standardized measure of discounted future net cash flows applicable to proved oil and natural gas reserves is as follows :

	2014	2013
Balance, beginning of year	$ 19,690,598	$ 2,909,000
Sales and transfers of oil and gas produced during the period	(4,310,813)	(905,125)
Net change in sales and transfer prices and in production (lifting) costs related to future production	(9,497,301)	(1,647,568)
Net change due to purchases of minerals in place	-	30,474,988
Net change due to extensions and discoveries	14,340,815	22,411,372
Changes in estimated future development costs	(13,990,412)	(17,355,723)
Previously estimated development costs incurred during the period	15,980,816	(3,181,356)
Net change due to revisions in quantity estimates	(12,814,002)	(4,633,853)
Other	2,487,713	(1,468,500)
Accretion of discount	4,715,661	(318,085)
Net change in income taxes	6,415,891	(6,594,552)
Balance, end of year	$ 23,018,966	$ 19,690,598

Due to the inherent uncertainties and the limited nature of reservoir data, both proved and probable reserves are subject to change as additional information becomes available. The estimates of reserves, future cash flows, and present value are based on various assumptions, including those prescribed by the SEC, and are inherently imprecise. Although we believe these estimates are reasonable, actual future production, cash flows, taxes, development expenditures, operating expenses, and quantities of recoverable oil and natural gas reserves may vary substantially from these estimates.

In estimating probable reserves, it should be noted that those reserve estimates inherently involve greater risk and uncertainty than estimates of proved reserves. While analysis of geoscience and engineering data provides reasonable certainty that proved reserves can be economically producible from known formations under existing conditions and within a reasonable time, probable reserves involve less certainty than reserves with a higher classification due to less data to support their ultimate recovery. Probable reserves have not been discounted for the additional risk associated with future recovery. Prospective investors should be aware that as the categories of reserves decrease with certainty, the risk of recovering reserves at the PV-10 calculation increases. The reserves and net present worth discounted at 10% relating to the different categories of proved and probable have not been adjusted for risk due to their uncertainty of recovery and thus are not comparable and should not be summed into total amounts.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

UNAUDITED SUPPLEMENTARY INFORMATION - *continued*

Reserve Estimation Process, Controls and Technologies

The reserve estimates, including PV-10 estimates, set forth above were prepared by Netherland, Sewell & Associates, Inc. with respect to the Company's Marcelina Creek Project in Texas, and PeTech Enterprises, Inc. for the Company's properties in Oklahoma. A copy of their full reports with regard to our reserves is attached as Exhibit 99.1 to this annual report on Form 10-K. These calculations were prepared using standard geological and engineering methods generally accepted by the petroleum industry and in accordance with SEC financial accounting and reporting standards.

Our Chairman of our Board of Directors is an experienced and qualified geoscience professional with a degree in geophysical science, but we do not have any employees with specific reservoir engineering qualifications in the company. Our Chairman and Chief Executive Officer worked closely with Netherland, Sewell & Associates, Inc. and PeTech Enterprises Inc. in connection with their preparation of our reserve estimates, including assessing the integrity, accuracy, and timeliness of the methods and assumptions used in this process.

The reserves estimates for the Marcelina Creek Project included herein have been independently evaluated by Netherland, Sewell & Associates, Inc. (NSAI), a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical person primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein is Mr. Neil H. Little. Mr. Little, a Licensed Professional Engineer in the State of Texas (No. 117966), has been practicing consulting petroleum engineering at NSAI since 2011 and has over 9 years of prior industry experience. He graduated from Rice University in 2002 with a Bachelor of Science Degree in Chemical Engineering and from the University of Houston in 2007 with a Master of Business Administration Degree. Mr. Little meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; Mr. Little is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

PeTech Enterprises, Inc. ("PeTech"), who provided reserve estimates for our Oklahoma Properties, is a Texas based profitable, family owned oil and gas production and Investment Company that provides reservoir engineering, economics and valuation support to energy banks, energy companies and law firms as an expert witness. The company has been in business since 1982. Amiel David is the President of PeTech and the primary technical person in charge of the estimates of reserves and associated cash flow and economics on behalf of the company for the results presented in its reserves report to us. He has a PhD in Petroleum Engineering from Stanford University. He is a registered Professional Engineer in the state of Texas (PE #50970), granted in 1982, a member of the Society of Petroleum Engineers and a member of the Society of Petroleum Evaluation Engineers.

Results of Operations for Oil and Gas Producing Activities For the Year Ended December 31, 2014	Total	Texas	Oklahoma	Kansas
Oil and Gas revenue	$ 5,455,555	$ 1,136,373	$ 3,997,379	$ 321,803
Production costs	1,253,090	516,451	634,739	101,900
Depreciation, depletion, and amortization	2,736,562	709,533	1,995,531	31,498
Exploration expenses	-	-	-	-
	3,989,652	1,225,984	2,630,270	133,398
Income tax expense	-	-	-	-
Results of Operations (excluding corporate overhead and interest costs)	$ 1,465,903	$ (89,611)	$ 1,367,109	$ 188,405

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

Not Applicable.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we evaluated the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act, as of December 31, 2014. Based on this evaluation, our principal executive officer and principal financial officer concluded that, as of the end of the period covered by this report, our disclosure controls and procedures were effective to ensure that the information required to be disclosed by us in the reports we submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the applicable rules and forms and that such information was accumulated and communicated to our principal executive officer and principal financial officer, in a manner that allowed for timely decisions regarding disclosure,

Changes in internal control over financial reporting

During the three months ended December 31, 2014, there have been no changes in our internal control over financial reporting that have materially affected or are reasonably likely to materially affect internal control over financial reporting.

Management's Annual Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) of the Exchange Act). Our management conducted an evaluation of the effectiveness of our internal control over financial reporting based on the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework and Internal Control over Financial Reporting – Guidance for Smaller Public Companies. Based on this evaluation, management concluded that, our internal control over financial reporting is effective.

Limitations on Effectiveness of Controls and Procedures

Our management, including our principal executive officer and principal financial officer, does not expect that disclosure controls or internal controls will prevent all error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. In addition, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within a company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake.

Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people or by management's override of the control. The design of any systems of controls is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Over time, control may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of these inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. Individual persons may perform multiple tasks which normally would be allocated to separate persons and therefore extra diligence must be exercised during the period these tasks are combined.

ITEM 9B. OTHER INFORMATION

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Our executive officers and directors are as follows:

Name	Age	Position(s) and Office(s)
John A. Brda	50	President, Chief Executive Officer, Secretary and Director
Willard G. McAndrew III	60	Chief Operating Officer and Director
Roger N. Wurtele	68	Chief Financial Officer
Thomas Lapinski	70	Chairman of the Board
Wayne Turner	66	Director
Jerry D. Barney	68	Director
Edward J. Devereaux	72	Director
Eunis L. Shockey	78	Director

Below is certain biographical information of our executive officers and directors:

John A. Brda – Mr. Brda has been our Chief Executive Officer since December 2014 and our President and Secretary and a member of the Board of Director since January 2012. He has been the Managing Member of Brda & Company, LLC since 2002, which provided consulting services to public companies—with a focus in the oil and gas sector—on investor relations, equity and debt financings, strategic business development and securities regulation matters, prior to him becoming President of the company.

We believe Mr. Brda is an excellent fit to our Board of Directors and management team based on his extensive experience in transaction negotiation and business development, particularly in the oil and gas sector as well as other non-related industries. He has consulted with many public companies in the last ten years, and we believe that his extensive network of industry professionals and finance firms will contribute to our success.

Willard G. McAndrew III – Mr. McAndrew has served as our Chief Operating Officer since September 2013 and as a member of the Board since October 2013. He has forty three years of experience in the energy industry, from field operations to refining. From December 2006 to September 2013, Mr. McAndrew served as the Chairman of the Board, CEO and President of Xtreme Oil & Gas, Inc., a company engaged in the acquisition, operation and development of oil and natural gas properties located in Texas and the southeast region of the United States. He began his career in 1969, gaining experience working for Hercules Drilling Company as a roustabout in South Louisiana. Mr. McAndrew attended Louisiana State University and then spent two years in the United States Marine Corps. Later, he joined Exxon Corporation Refinery's Distillation and Specialties division in Baton Rouge, Louisiana, becoming the fourth generation in his family to work for Exxon. Mr. McAndrew has served as President and owner of several small companies that were involved in all phases of the oil and gas business from drilling, reworking, completion, leases, etc. He has also been a consultant since 1990 to companies and is responsible for the structure, formation and marketing of partnerships and energy financing.

We believe that Mr. McAndrew's many years in the oil and gas industry and his vast network of contacts in the investment banking and broker-dealer communities compliments the Board of Directors.

Involvement in certain legal proceedings. From 2001 through May 2006, Mr. McAndrew served as the CEO, President and Director of Energy & Engine Technology, Inc. After he left the company, it filed for bankruptcy protection in December 2006.

Roger N. Wurtele – Mr. Wurtele has served as our Chief Financial Officer since September 2013. He is a versatile, experienced finance executive that has served as Chief Financial Officer for several public and private companies. He has a broad range of experience in public accounting, corporate finance and executive management. Mr. Wurtele previously served as CFO of Xtreme Oil & Gas, Inc. from February 2010 to September 2013. From May 2013 to September 2013 he worked as a financial consultant for us. From November 2007 to January 2010, Mr. Wurtele served as CFO of Lang and Company LLC, a developer of commercial real estate projects. He graduated from the University of Nebraska and has been a Certified Public Accountant for 40 years.

Involvement in certain legal proceedings. From 2001 through May 2006, Mr. Wurtele served as the CFO of Energy & Engine Technology, Inc. After he left the company, it filed for bankruptcy protection in December 2006.

Thomas Lapinski – Mr. Lapinski has served as our Chairman of the Board since December 2014. Prior to that, he served as our Chief Executive Officer and director from November 2010 to December 2014. He also previously served as our President from November 2010 to January 2012 and as Interim Principal Financial Officer from November 2010 to September 2013. He is the founder of Torchlight Energy, Inc., our wholly owned subsidiary, and has served as its Chief Executive Officer, President and director since its incorporation in June 2010. From 2002 to the present, he has engaged in consulting work on evaluating exploration, acquisition and re-development opportunities in the Rocky Mountain Region, Texas Gulf Coast, Mid-Continent, the Middle East, and South America. From September 1996 to June 2002, Mr. Lapinski served as President of Stephens Energy International of The Stephens Group, LLC. While there, he was involved in oil and gas exploration and production project development. Prior to that, he spent over 30 years in senior positions with Amoco Corporation before retiring. His expertise is in project evaluations, operations management and strategic planning with experience throughout the Rocky Mountain region, Alaska, U.S. mid-continent, the U.S. Gulf Coast and international arenas. With Amoco, he has held numerous positions, including Division Geophysicist for Rocky Mountain Area, Regional Geophysicist for Africa and the Middle East, Exploration Manager for North and West Africa, President-Amoco Morocco, President-Amoco Turkey, General Manager-Amoco Kenya, Exploration Manager Gulf Coast, Regional Exploration Manager for Southern and Eastern U.S. and Manager for Resource and Business Development in Southern Rocky Mountain Area. He also spent time on a special project for the Chairman of Amoco on key strategic planning issues where he was responsible for long-term monetization of Amoco's North American asset base. Mr. Lapinski received a degree in Geophysical Engineering from the Colorado School of Mines in 1966.

We appointed Mr. Lapinski as Chairman of the Board of Directors based on his knowledge and experience in the oil and gas industry. His ability to identify and evaluate opportunities is an important part of our continued success.

Wayne Turner – Mr. Turner has served as one of our directors since March 2011. He is presently the Managing Partner of JEBCO Seismic, LP, a position he has held since 1989, and is the Managing Partner of Big Thicket Oil & Gas, L.P., a position he has held since 2001. Mr. Turner took over management of JEBCO in 1989, when he acquired an ownership interest in the company. JEBCO is an independent international geophysical data acquisition contractor. Jebco's non-exclusive surveys and third party datasets represent a unique and readily available source of information for both mature and frontier regions. JEBCO has operated both offshore and onshore in Canada and the U.S. JEBCO has also conducted surveys in the North Sea, Africa, Asia, and South America. One of JEBCO's most significant accomplishments was signing an agreement with the Ministry of Geology in the USSR in 1989. The company was active in Russia, Kazakhstan, Uzbekistan, and Azerbaijan before and after the break-up of the USSR. The company has provided oil and gas exploration information to the industry, assisted in license rounds, and assisted in direct negotiations for oil and gas properties in these countries. Mr. Turner spent significant time in these countries and personally negotiated the major contract agreements involved.

Mr. Turner started Big Thicket Oil & Gas, L.P. in 2001. This company is active in oil and gas exploration in Texas, Louisiana, Oklahoma, and New Mexico. Most of the activity is through partnerships, which allows the company to remain small in staff, but have access to expertise in different areas. Big Thicket does not operate wells, but is involved in generating and evaluating prospects. Mr. Turner graduated in 1971 from the University of Houston with a degree in Electrical Engineering. He is active in various charitable organizations including the Houston Livestock Show and Rodeo and Houston Children's Charities.

Wayne Turner's expertise in the oil and gas industry makes him an excellent fit to the Board of Directors. In particular, we believe his experience in geophysical data acquisition is a valuable asset to the company.

Jerry Barney – Dr. Barney has served as member of the Board of Directors since October 2013. He has over 30 years of experience in various management and consulting positions with technology, oil services and government entities. Dr. Barney was a director of Barney Family Companies, a successful investment firm with holdings in oil and gas properties, office buildings and financial assets. Dr. Barney has a Bachelor of Science from the University of Kansas; a MA and EdD in Education from Columbia University; and a MBA from Rensselaer University.

We believe that Dr. Barney's broad range of business experience and skills, punctuated by noteworthy higher education credentials, compliments the Board of Directors.

Edward Devereaux – Mr. Devereaux has served as member of the Board of Directors since October 2013. He is a seasoned investment executive with over three decades of experience in investment management, investment banking and securities sales and marketing. From 2010 to the present, he has served as a consultant to companies wishing to raise capital within the independent broker dealer and registered investment advisors communities. From 2006 to 2010, he served as President and CEO of Advanced Marketing Services, a marketing consulting and investment banking firm. Mr. Devereaux has participated in raising more than $10 billion of investment capital in his career. He has worked for various investment firms, including Prudential Securities and Lightstone Securities. Mr. Devereaux has a B.A. from Hofstra University.

Edward Devereaux expertise in the securities industry makes him an excellent fit to the Board of Directors. In particular, we believe his oversight of our capital raising strategies is a valuable asset to the company.

Eunis L. Shockey – Mr. Shockey has served as member of the Board of Directors since October 2013. He is a successful and experienced entrepreneur and executive. Mr. Shockey retired in 2000, but since then he has acted as a mentor for many of the companies in his investment portfolio. After completing his service in the U.S. Navy, Mr. Shockey entered the software industry and gained broad knowledge of military software and telephony applications while at GE, RCA, Raytheon, and Northern Telecom. He founded Computerware in 1978 and successfully developed and marketed a telephone company management system for shared tenant services. Computerware was bought by a venture capital fund in 1986. Mr. Shockey then founded Telecommunications Support Systems (TSS) to dispatch substitute teachers for schools. Its customers included 600 of the largest school districts in the U.S. and Canada. TSS was sold in 2000 and currently operates as eSchools Solutions, Inc.

We believe Mr. Shockey is an excellent fit to our Board of Directors based on his extensive experience in successfully owning and operating multiple successful companies over the years.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires our directors and executive officers, and persons who own beneficially more than ten percent of our common stock, to file reports of ownership and changes of ownership with the Securities and Exchange Commission. Based solely upon a review of Forms 3, 4 and 5 furnished to us during the fiscal year ended December 31, 2014, we believe that the directors, executive officers, and greater than ten percent beneficial owners have complied with all applicable filing requirements during the fiscal year ended December 31, 2014, with the exception of (i) a Form 3/A and two Form 4's that Jerry Barney, a member of the Board, filed late, and (ii) a Form 4 that Robert Kenneth Dulin, a significant beneficial shareholder, filed late.

Code of Ethics

We have adopted a code of ethics that applies to our principal executive officer, principal financial officer, principal accounting officer or controller, or persons performing similar functions. The Code of Ethics is available at our website at torchlightenergy.com. Further, we undertake to provide by mail to any person without charge, upon request, a copy of such code of ethics if we receive the request in writing by mail to: Torchlight Energy Resources, Inc., 5700 W. Plano Parkway, Suite 3600, Plano, Texas 75093.

Procedures for Stockholders to Recommend Nominees to the Board

There have been no material changes to the procedures by which stockholders may recommend nominees to our Board of Directors since we last provided disclosure regarding this process.

Audit Committee

We maintain a separately-designated standing audit committee. The Audit Committee currently consists of three our four independent directors, including Wayne Turner, Jerry D. Barney and Edward J. Devereaux. Mr. Devereaux is the Chairman of the Audit Committee, and the Board of Directors has determined that he is an audit committee financial expert as defined in Item 5(d)(5) of Regulation S-K. The primary purpose of the Audit Committee is to oversee our accounting and financial reporting processes and audits of our financial statements on behalf of the Board of Directors. The Audit Committee meets privately with our management and with our independent registered public accounting firm and evaluates the responses by our management both to the facts presented and to the judgments made by our outside independent registered public accounting firm.

ITEM 11. EXECUTIVE COMPENSATION

The following table provides summary information for the years 2014 and 2013 concerning cash and non-cash compensation paid or accrued to or on behalf of certain executive officers.

Summary Executive Compensation Table

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards ($)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation ($)	All Other Compensation ($)	Total ($)
Thomas Lapinski	2014	-0-	-	-		-	-	180,000	180,000
Former	2013	180,000	-	-	355,250 (1)	-	-		535,250
CEO/Director		(2)							
John A. Brda	2014	300,000,	-	-		-	-	-	300,000
President/Director	2013	205,000	-	-	355,250 (3)	-	-	-	560,250
		(4)							
Willard G.	2014	300,000	-	-		-	-		300,000
McAndrew III	2013	60,000	-	-	2,225,000	-	-	75,000 (6)	2,360,000
COO/Director					(5)				
Roger Wurtele	2014	180,000	-	-		-	-		180,000
CFO	2012	40,000	-	-	180,000 (7)	-	-	52,500 (6)	272,500

(1) On September 4, 2013, we granted Mr. Lapinski a fully vested option to purchase 245,000 shares of stock at an exercise price of $2.00 per share. The value of these options was determined using the Black Scholes Method.
(2) In September 2013, Mr. Lapinski forgave a total of $489,000 in outstanding indebtedness in connection with his then accrued and unpaid compensation, which included this unpaid salary for 2012.
(3) On September 4, 2013, we granted Mr. Brda a fully vested option to purchase 245,000 shares of stock at an exercise price of $2.00 per share. The value of these options was determined using the Black Scholes Method.
(4) In September 2013, Mr. Brda forgave a total of $240,000 in outstanding indebtedness in connection with his then accrued and unpaid compensation, which included this unpaid salary for 2012.
(5) Prior to Mr. McAndrew's appointment as COO in September 2013, during 2013 we granted him a fully vested warrant to purchase 1,000,000 shares of stock at an exercise price of $2.09 per share as consideration for consulting services, valued at $890,000. In September 2013, we granted Mr. McAndrew an option to purchase 1,500,000 shares of stock at an exercise price of $2.09 per share, which vested in January, 2014 and was valued at $1,335,000. The value of the options was determined using the Black Scholes Method.
(6) This amount represents consulting fees paid prior to the effective date of employment with the Company.
(7) In October 2013, we granted Mr. Wurtele an option to purchase 300,000 shares of stock at an exercise price of $2.09 per share. 100,000 of the options vested immediately, with the remaining options vesting in January, 2014. The value of these options was determined using the Black Scholes Method.

Setting Executive Compensation

We fix executive base compensation at a level we believe enables us to hire and retain individuals in a competitive environment and to reward satisfactory individual performance and a satisfactory level of contribution to our overall business goals. We also take into account the compensation that is paid by companies that we believe to be our competitors and by other companies with which we believe we generally compete for executives.

In establishing compensation packages for executive officers, numerous factors are considered, including the particular executive's experience, expertise, and performance, our company's overall performance, and compensation packages available in the marketplace for similar positions. In arriving at amounts for each component of compensation, our Compensation Committee strives to strike an appropriate balance between base compensation and incentive compensation. The Compensation Committee also endeavors to properly allocate between cash and non-cash compensation (including without limitation stock and stock option awards) and between annual and long-term compensation.

Employment Agreements

We entered into an employment agreement with John A. Brda, our president, in January 2012. The agreement, as amended in October 2013, has a term that expires in December 2016 and provided for a base salary of $15,000 per month. The agreement was amended in January 2014 so that effective the first of that month, his annual base salary increased to $300,000. He is also eligible for a discretionary annual bonus based on factors to be considered by the Board of Directors. The employment agreement includes a confidentiality provision and a non-compete provision.

We entered into an employment agreement with Willard G. McAndrew III, our Chief Operating Officer, in September 2013. The agreement has a term of three years and provided for a base salary of $15,000 per month. Additionally, the agreement granted Mr. McAndrew 1,500,000 stock options in September 2013 that were to vest upon certain production thresholds being met by the company. The agreement was amended in January 2014 so that effective the first of that month, his annual base salary increased to $300,000 and all of the 1,500,000 options became fully vested. These options are currently held by WMDM Family, Ltd. Mr. McAndrew is also eligible for a discretionary annual bonus based on factors to be considered by the Board of Directors. The employment agreement includes a confidentiality provision and a non-compete provision.

We entered into an employment agreement with Roger Wurtele, our Chief Financial Officer, in October 2013 that has a term that ends in September 2016 and provides for a base salary of $10,000 per month. Additionally, the agreement granted Mr. Wurtele 300,000 stock options in October 2013, with 100,000 options vesting immediately and the remaining 200,000 options to vest upon the second and third anniversaries of his employment. The agreement was amended in January 2014 so that effective the first of that month, his annual base salary increased to $180,000 and the remaining 200,000 options became fully vested. These options are currently held by Birch Glen Investments Ltd. Mr. Wurtele is also eligible for a discretionary annual bonus based on factors to be considered by the Board of Directors. The employment agreement includes a confidentiality provision and a non-compete provision.

Outstanding Equity Awards at Fiscal Year End

The following table details all outstanding equity awards held by our named executive officers at December 31, 2014:

	Option Awards				
Name	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexercised Options (#) Unexercisable	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)	Option Exercise Price ($)	Option Expiration Date
Thomas Lapinski	245,000	-	-	2.00	09/04/2018
John A. Brda	245,000	-	-	2.00	09/04/2018
Willard G. McAndrew III	900,000 (1)	-	-	2.09	04/15/2018
	1,500,000 (1) (2)	-	-	2.09	09/09/2018
Roger Wurtele	300,000 (3) (4)	-	-	2.09	10/10/2018

(1) Mr. McAndrew gifted these options to WMDM Family, Ltd. The general partner and 1% owner of WMDM Family, Ltd. is a limited liability company which is owned by a trust of which Mr. McAndrew is a beneficiary.
(2) These options were awarded to Mr. McAndrew in September 2013, and vested on January 2, 2014.
(3) Mr. Wurtele gifted these options to Birch Glen Investments Ltd. Mr. Wurtele and his wife together hold a 98% interest in the general partner of Birch Glen Investments Ltd.
(4) These options were awarded to Mr. Wurtele in October 2013. 100,000 options vested in October 2013 and the remaining 200,000 options vested on January 2, 2014.

Compensation of Directors

At present, we do not pay our directors for attending meetings of the Board of Directors, although we may adopt a director compensation policy in the future. We have no standard arrangement pursuant to which directors are compensated for any services they provide or for committee participation or special assignments. We did, however, provide compensation to certain directors in the form of restricted common stock during the year ended December 31, 2013. No Director compensation was paid in 2014.

Summary Director Compensation Table

Name	Fees Earned of Paid in Cash ($)	Stock Awards ($) (A)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)	Total ($)
Wayne Turner	-	-0-	-	-	-	-	-0-
Jerry Barney	-	-0-	-	-	-	-	-0-
Edward Devereaux	-	-0-	-	-	-	-	-0-
Eunis L. Shockey	-	-0-	-	-	-	-	-0-

(A) Stock Value as applicable is determined using the Black Scholes Method.

Compensation Policies and Practices as they Relate to Risk Management

We attempt to make our compensation programs discretionary, balanced and focused on the long term. We believe goals and objectives of our compensation programs reflect a balanced mix of quantitative and qualitative performance measures to avoid excessive weight on a single performance measure. Our approach to compensation practices and policies applicable to employees and consultants is consistent with that followed for its executives. Based on these factors, we believe that our compensation policies and practices do not create risks that are reasonably likely to have a material adverse effect on us.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth information, as of April 7, 2015, concerning, except as indicated by the footnotes below, (i) each person whom we know beneficially owns more than 5% of our common stock, (ii) each of our directors, (iii) each of our named executive officers, and (iv) all of our directors and executive officers as a group. Unless otherwise noted below, the address of each beneficial owner listed in the table is c/o Torchlight Energy Resources, Inc., 5700 W. Plano Parkway, Suite 3600, Plano, Texas 75093. We have determined beneficial ownership in accordance with the rules of the SEC. Except as indicated by the footnotes below, we believe, based on the information furnished to us, that the persons and entities named in the table below have sole voting and investment power with respect to all shares of common stock that they beneficially own, subject to applicable community property laws. Applicable percentage ownership is based on 23,478,441 shares of common stock outstanding at April 7, 2015. In computing the number of shares of common stock beneficially owned by a person and the percentage ownership of that person, we deemed outstanding shares of common stock subject to stock options or warrants held by that person that are currently exercisable or exercisable within 60 days of April 7, 2015 and shares of common stock issuable upon conversion of other securities held by that person that are currently convertible or convertible within 60 days of April 7, 2015. We did not deem these shares outstanding, however, for the purpose of computing the percentage ownership of any other person. Unless otherwise noted, stock options and warrants referenced in the footnotes below are currently fully vested and exercisable. Beneficial ownership representing less than 1% is denoted with an asterisk (*).

Name and address of beneficial owner	Amount of beneficial ownership	Percent of class
Thomas Lapinski Chairman of the Board	3,250,000 shares (1)	13.70%
John A. Brda President, CEO, Secretary and Director	2,762,000 shares (2)	11.64%
Willard G. McAndrew III COO and Director	2,400,000 shares (3)	9.27%
Roger N. Wurtele Chief Financial Officer	300,000 shares (4)	1.26%
Jerry D. Barney Director	198,255 shares (5)	*
Edward J. Devereaux Director	37,000 shares	*
Eunis L. Shockey Director	134,000 shares (6)	*
Wayne Turner Director	75,000 shares	*
All directors and executive officers as a group (eight persons)	9,156,255 shares	34.18%
Robert Kenneth Dulin (7)	2,636,718 shares (8)	10.52%
Sawtooth Properties, LLLP (7)	1,131,216 shares (9)	4.70%
Castleton Investment Management L.P. (10)	2,260,000 shares (11)	9.08%
Zenith Petroleum Corporation (12)	1,908,356 shares	8.06%

(1) Includes 3,005,000 shares of common stock and stock options that are exercisable into 245,000 shares of common stock.

(2) Includes 187,000 shares of common stock and stock options that are exercisable into 245,000 shares of common stock, both held individually by John A. Brda. Also includes 2,330,000 shares of common stock held by Brda & Company LLC. Mr. Brda is the sole owner and Managing Director of this entity and has voting and investment authority over the shares held by it.

(3) Includes securities held by WMDM Family, Ltd., including warrants that are exercisable into 900,000 shares of common stock and stock options that are exercisable into 1,500,000 shares of common stock. The general partner and 1% owner of WMDM Family, Ltd. is a limited liability company of which Mr. McAndrew is the manager. He has voting and investment authority over the shares held by WMDM Family, Ltd.

(4) Includes stock options held by Birch Glen Investments Ltd. that are exercisable into 300,000 shares of common stock. Mr. Wurtele and his wife together hold a 98% interest in the general partner of Birch Glen Investments Ltd., and Mr. Wurtele shares voting and investment authority over the shares held by Birch Glen Investments Ltd. Additionally, the general partner and 1% owner of WMDM Family, Ltd. (see footnote "(3)" above) is a limited liability company which is owned by a trust of which Mr. Wurtele is the trustee. Securities held by WMDM Family, Ltd. are not included, however, because Mr. Wurtele is not deemed to have voting or investment authority over the shares held by WMDM Family, Ltd.

(5) Includes (a) 25,000 shares of common stock held individually by Dr. Barney; and (b) securities held by an entity that is wholly-owned by the Barney 2012 Children's Trust, including 153,255 shares of common stock and a Series A Warrant that is exercisable into 20,000 shares of common stock. Dr. Barney is a beneficiary of the Barney 2012 Children's Trust and historically has had influence over decisions made by the trustee who has voting and investment authority over the shares held by the trust.

(6) Includes 34,000 shares of common stock and warrants that are exercisable into 100,000 shares of common stock.

(7) Address: 8449 Greenwood Drive, Niwot, Colorado, 80503.

(8) Includes (a) securities held individually by Robert Kenneth Dulin, including 66,860 shares of common stock and warrants that are exercisable into 150,000 shares of common stock; (b) 209,500 shares of common stock held in trust for the benefit of immediate family members of Mr. Dulin; (c) securities held by Sawtooth Properties, LLLP ("Sawtooth"), including (i) 535,074 shares of common stock, (ii) warrants that are exercisable into 433,285 shares of common stock and (iii) promissory notes that are convertible into up to 162,857 shares of common stock; (d) securities held by another limited liability limited partnership ("LLLP2"), including (i) 125,000 shares of common stock, (ii) warrants that are exercisable into 133,000 shares of common stock and (iii) promissory notes that are convertible into up to 90,000 shares of common stock; and (e) securities held by a limited liability company ("LLC1"), including (i) 120,000 shares of common stock, (ii) warrants that are exercisable into 448,285 shares of common stock and (iii) promissory notes that are convertible into up to 162,857 shares of common stock. Mr. Dulin is trustee/custodian of each of the trusts and/or accounts referenced in "(b)" above and has voting and investment authority over the shares held by them. Mr. Dulin is the Managing Partner of Sawtooth Properties, LLLP, the Managing Partner of LLLP2 and the Managing Member of LLC1, and he has voting and investment authority over the shares held by each entity.

(9) Includes (i) 535,074 shares of common stock, (ii) warrants that are exercisable into 433,285 shares of common stock and (iii) a promissory note that, as of June 18, 2013, is convertible into up to 162,857 shares of common stock. Robert Kenneth Dulin is the Managing Partner of Sawtooth Properties, LLLP.

(10) Castleton Investment Management L.P. ("Shareholder") beneficially owns these securities. Castleton Investment Management GP Ltd. ("Castleton GP") is the general partner of the Shareholder. Castleton Investment Management LLC is the investment advisor to the Shareholder with respect to the securities. The address for each of these entities is 2200 Atlantic Street, Suite 800, Stamford, CT 06902-6834.

(11) Includes (a) 860,000 shares of common stock, and (b) warrants to purchase 1,400,000 shares of common stock. Under the Warrant Agreement, the Shareholder's ability to purchase the additional 1,400,000 shares of common stock is subject to a contractual restriction that limits the Shareholder's ability to exercise the warrant to the extent that after giving effect to any such exercise it would beneficially own more than 9.99% of the outstanding common stock.

(12) Address: 7790 E. Arapahoe Rd., #190, Centennial, Colorado 80112.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

On November 4, 2014, Eunis L. Shockey loaned us $500,000 under a 30 day promissory note. The promissory note accrues interest at an annual rate of 10%. We did not make payment on the note on the December 4, 2014 maturity date, and are having ongoing discussions with Mr. Shockey on how to satisfy this obligation.

In December 2014, Robert Kenneth Dulin, a major shareholder, loaned us $100,000 under a promissory note. The promissory note accrues interest at an annual rate of 12% and is due on April 30, 2015. We also issued him 150,000 warrants in connection with the transaction.

In April 2015, Mr. Dulin advanced us $150,000 in connection with a proposed acquisition of net production in the Oregrande project. We are still in the process of negotiating the terms of the acquisition with Mr. Dulin.

Director Independence

We currently have four independent directors on our Board, Wayne Turner, Jerry Barney, Edward Devereaux, and Eunis L. Shockey. The definition of "independent" used herein is based on the independence standards of The NASDAQ Stock Market LLC. The Board performed a review to determine the independence of Wayne Turner, Jerry Barney, Edward Devereaux, and Eunis L. Shockey and made a subjective determination as to each of these directors that no transactions, relationships, or arrangements exist that, in the opinion of the Board, would interfere with the exercise of independent judgment in carrying out the responsibilities of a director of Torchlight Energy Resources, Inc. In making these determinations, the Board reviewed information provided by these directors with regard to each Director's business and personal activities as they may relate to us and our management.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The following table sets forth the fees paid or accrued by us for the audit and other services provided or to be provided by Calvetti Ferguson, our independent registered public accountants, during the years ended December 31, 2014 and 2013.

	2014	2013
Audit Fees(1)	$ 123,655	$ 73,830
Audit Related Fees(2)	0	0
Tax Fees(3)	13,825	3,298
All Other Fees	17,704	7560
Total Fees	$ 155,184	$ 84,688

(1) Audit Fees: This category represents the aggregate fees billed for professional services rendered by the principal independent accountant for the audit of our annual financial statements and review of financial statements included in our Form 10-K and services that are normally provided by the accountant in connection with statutory and regulatory filings or engagements for the fiscal years.
(2) Audit Related Fees: This category consists of the aggregate fees billed for assurance and related services by the principal independent accountant that are reasonably related to the performance of the audit or review of our financial statements and are not reported under "Audit Fees."
(3) Tax Fees: This category consists of the aggregate fees billed for professional services rendered by the principal independent accountant for tax compliance, tax advice, and tax planning.

Pre-Approval of Audit and Non-Audit Services

We did not have a standing audit committee of the board of directors until November, 2013. Therefore, for the fiscal years ended December 31, 2014 and 2013, all audit services, audit-related services, as described above, were provided to us by Calvetti Ferguson based upon prior approval of the Board of Directors. Whitley Penn has been engaged for tax services for the year 2014 including preparation of 2013 tax returns.

PART IV

ITEM 15. EXHIBITS

Exhibit No.	Description
2.1	Share Exchange Agreement dated November 23, 2010. (Incorporated by reference from Form 8-K filed with the SEC on November 24, 2010.) *
3.1	Articles of Incorporation. (Incorporated by reference from Form S-1 filed with the SEC on May 2, 2008.) *
3.2	Amended and Restated Bylaws (Incorporated by reference from Form 8-K filed with the SEC on January 12, 2011.) *
10.1	Agreement to Participate in Oil and Gas Development Joint Venture between Bayshore Operating Corporation, LLC and Torchlight Energy, Inc. (Incorporated by reference from Form 8-K filed with the SEC on November 24, 2010) *
10.2	Purchase and Sale Agreement between Torchlight Energy Inc. and Xtreme Oil and Gas Inc..effective April 1, 2013. (Incorporated by reference from Form 10-Q filed with the SEC on May 15, 2013)*
10.3	Employment Agreement with John A. Brda (Incorporated by reference from Form 8-K filed with the SEC on October 15, 2013.) *
10.4	Amendment to Employment Agreement with John A. Brda (Incorporated by reference from Form 10-K filed with the SEC on March 31, 2014.) *
10.5	Employment Agreement with Roger Wurtele (Incorporated by reference from Form 8-K filed with the SEC on October 15, 2013.) *
10.6	Amendment to Employment Agreement with Roger Wurtele (Incorporated by reference from Form 10-K filed with the SEC on March 31, 2014.) *
10.7	Employment Agreement with Willard McAndrew III (Incorporated by reference from Form 8-K filed with the SEC on October 15, 2013.) *
10.8	Amendment to Employment Agreement with Willard McAndrew III (Incorporated by reference from Form 8-K filed with the SEC on October 15, 2013.) *
10.9	Second Amendment to Employment Agreement with Willard McAndrew III (Incorporated by reference from Form 10-K filed with the SEC on March 31, 2014.) *
10.10	Development Agreement between Ring Energy, Inc. and Torchlight Energy Resources, Inc. (Incorporated by reference from Form 8-K filed with the SEC on October 22, 2013.) *
10.11	Coulter Limited Partnership Agreement dated January 10, 2012 (Incorporated by reference from Form 10-Q filed with the SEC on August 14, 2014.) *
10.12	Promissory Note with Boeckman Well LLC dated May 1, 2013 and amendments thereto (Incorporated by reference from Form 10-Q filed with the SEC on August 14, 2014.) *
10.13	12% Series A Secured Convertible Promissory Note (form of) (Incorporated by reference from Form 10-Q filed with the SEC on August 14, 2014.) *
10.14	Securities Purchase Agreement (form of), January 2014 (Incorporated by reference from Form 10-Q filed with the SEC on August 14, 2014.) *
10.15	Registration Rights Agreement (form of), January 2014 (Incorporated by reference from Form 10-Q filed with the SEC on August 14, 2014.) *
14.1	Code of Ethics (Incorporated by reference from Form S-1 filed with the SEC on May 2, 2008.) *

ITEM 15. EXHIBITS - *continued*

21.1	Subsidiaries
31.1	Certification of principal executive officer required by Rule 13a – 14(1) or Rule 15d – 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of principal financial officer required by Rule 13a – 14(1) or Rule 15d – 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of principal executive officer and principal financial officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and Section 1350 of 18 U.S.C. 63.
99.1	Report of Netherland, Sewell & Associates, Inc. and Wright & Company, Inc.
99.2	Report of PeTech Enterprises, Inc.
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation Linkbase
101.DEF	XBRL Taxonomy Extension Definitions Linkbase
101.LAB	XBRL Taxonomy Extension Label Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase

* Incorporated by reference from our previous filings with the SEC

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Torchlight Energy Resources, Inc.

/s/ *John A. Brda*
By: John A. Brda
Chief Executive Officer

Date: April 15, 2015

Pursuant to the requirements of the Securities Exchange Act of 1934, 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/ Thomas Lapinski Thomas Lapinski	Director and Chairman of the Board	April 15, 2015
/s/ John A. Brda John A. Brda	Director, Chief Executive Officer and Secretary	April 15, 2015
/s/ Willard G. McAndrew III Willard G. McAndrew III	Director and Chief Operating Officer	April 15, 2015
/s/ Roger N. Wurtele Roger N. Wurtele	Chief Financial Officer	April 15, 2015
/s/ Wayne Turner Wayne Turner	Director	April 15, 2015
/s/ Jerry D. Barney Jerry D. Barney	Director	April 15, 2015
/s/ Edward J. Devereaux Edward J. Devereaux	Director	April 15, 2015
/s/ Eunis L. Shockey Eunis L. Shockey	Director	April 15, 2015

Exhibit 21.1

Subsidiaries of the Registrant

Name	State of Organization
Torchlight Energy, Inc.	Nevada
Torchlight Energy Operating, LLC	Texas
Hudspeth Oil Corporation	Texas

Exhibit 31.1

CERTIFICATION PURSUANT TO SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, John A. Brda, certify that:

1. I have reviewed this annual report on Form 10-K of Torchlight Energy Resources, Inc. for the year ended December 31, 2014;

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

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

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

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the small business issuer, including its consolidated subsidiary, 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 fourth quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over the financial reporting; and

5. 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.

/s/ John A. Brda

By: John A. Brda
Chief Executive Officer
(Principal Executive Officer)
Date: April, 15, 2015

Exhibit 31.2

CERTIFICATION PURSUANT TO SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Roger Wurtele, certify that:

1. I have reviewed this annual report on Form 10-K of Torchlight Energy Resources, Inc. for the year ended December 31, 2014;

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

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

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

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the small business issuer, including its consolidated subsidiary, 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 fourth quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over the financial reporting; and

5. 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.

/s/ Roger Wurtele

By: Roger Wurtele,
Chief Financial Officer
(Principal Financial Officer)
Date: April 15, 2015

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

I, John A. Brda, certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the annual report on Form 10-K of Torchlight Energy Resources, Inc. for the year ended December 31, 2014, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that information contained in such annual report on Form 10-K fairly presents, in all material respects, the financial condition and results of operations of Torchlight Energy Resources, Inc.

/s/ John A. Brda
John A. Brda,
Chief Executive Officer (Principal Executive Officer)

Date: April 15, 2015

I, Roger Wurtele, certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the annual report on Form 10-K of Torchlight Energy Resources, Inc. for the year ended December 31, 2014, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that information contained in such annual report on Form 10-K fairly presents, in all material respects, the financial condition and results of operations of Torchlight Energy Resources, Inc.

/s/ Roger Wurtele
Roger Wurtele,
Chief Financial Officer (Principal Financial Officer)

Date: April 15, 2015

The foregoing certification is not deemed filed with the Securities and Exchange Commission for purposes of Section 18 of the Securities Exchange Act of 1934, as amended ("Exchange Act"), and is not to be incorporated by reference into any filing of Torchlight Energy Resources, Inc. under the Securities Act of 1933, as amended, or the Exchange Act, whether made before or after the date hereof, regardless of any general incorporation language in such filing.

Exhibit 99.1

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

April 15, 2015

Mr. Thomas Lapinski
Torchlight Energy Resources, Inc.
5700 West Plano Parkway, Suite 3600
Plano, Texas 75093

Dear Mr. Lapinski:

In accordance with your request, we have estimated the proved and probable reserves and future revenue, as of December 31, 2014, to the Torchlight Energy Resources, Inc. (Torchlight) interest in certain oil properties located in Marcelina Creek Field, Wilson County, Texas. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute approximately 30 percent of all proved reserves owned by Torchlight. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Torchlight's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the oil reserves and future net revenue to the Torchlight interest in these properties, as of December 31, 2014, to be:

	Oil Reserves (MBBL)		Future Net Revenue (M$)	
Category	Gross (100%)	Net	Total	Present Worth at 10%
Proved Developed Producing	86.0	35.0	1,408.4	1,147.6
Proved Undeveloped	636.0	313.4	7,095.5	3,509.2
Total Proved	722.0	348.5	8,503.9	4,656.8
Probable Undeveloped	1,818.6	912.4	22,778.5	8,558.1

Totals may not add because of rounding.

The oil volumes shown include crude oil only. Oil volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Produced gas is flared or consumed in field operations.

The estimates shown in this report are for proved developed producing, proved undeveloped, and probable reserves. Our study indicates that there are no proved developed non-producing reserves for these properties at this time. As requested, possible reserves that exist for these properties have not been included. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Gross revenue is Torchlight's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Torchlight's share of production taxes, ad valorem taxes, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

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Oil prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2014. The average West Texas Intermediate posted price of $91.48 per barrel is adjusted by lease for quality, transportation fees, and market differentials. Oil prices are held constant throughout the lives of the properties. The average adjusted oil price weighted by production over the remaining lives of the properties is $88.86 per barrel.

Operating costs used in this report for properties in the Austin Chalk and Buda Reservoirs are based on operating expense records of Torchlight. Based on our knowledge of similar wells in the area, we have estimated operating costs at $12,000 per completion per month for properties in the Eagle Ford Shale Reservoir. All operating costs are intended to include the per-well overhead expenses allowed under joint operating agreements along with costs to be incurred at and below the district and field levels. Since all properties are nonoperated, our estimated operating costs do not include the headquarters general and administrative overhead expenses of Torchlight. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Torchlight and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for new development wells and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Torchlight's estimates of the costs to abandon the wells and production facilities, net of any salvage value. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Torchlight interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Torchlight receiving its net revenue interest share of estimated future gross production.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Torchlight, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

NETHERLAND, SEWELL & ASSOCIATES, INC.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for undeveloped locations; such reserves are based on analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Torchlight, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical person primarily responsible for preparing the estimates presented herein meets the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Neil H. Little, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2011 and has over 9 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

/s/ C.H. (Scott) Rees III
By:
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

/s/ Neil H. Little
By:
Neil H. Little, P.E. 117966
Vice President

Date Signed: April 15, 2015

NHL:AST

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir.* Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project.* A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well.* A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR).* Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs.* Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well.* An extension well is a well drilled to extend the limits of a known reservoir.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. *Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)*
b. *Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).*

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. *Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*
b. *Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*
c. *Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*
d. *Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*
e. *Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*
f. *Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

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

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category 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.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.

Exhibit 99.2

PETECH ENTERPRISES, INC

PeTech Enterprises, Inc.
5707 Spanish Oak, Houston, Texas 77066

APPRAISAL REPORT

ON CERTAIN PROPERTIES

owned by

TORCHLIGHT ENERGY RESOURCES, INC.

(HUNTON)

As of

December 31, 2014

April 9, 2015

Mr. John Brda

Chief Executive Officer

Torchlight Energy Resources, Inc.

5700 W. Plano Parkway #3600

Plano, TX 75093

Dear Mr. Brda,

At your request PeTech Enterprises, Inc. ("PEI") has prepared an estimate of certain hydrocarbon reserves owned by Torchlight Energy Resources, Inc. ("TER") in the State of Texas as of December 31, 2014. This evaluation was completed by April 8, 2015.

These estimates include only proved reserves and were prepared in accordance with the United States Securities and Exchange Commission ("SEC") guidelines rule 4-10 Regulation S-X for evaluating and reporting oil and gas reserves. Rule 4-10 defines reserves as **"…those quantities of oil and gas, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible-from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations-prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for estimation. ……..Reserves which can be produced through the application of improved recovery technique…..Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-months period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for completion. A more complete description of the rule is attached as an Appendix.**

Acceptable evaluation geological, engineering and accounting (cost, taxes, etc.) practice principles were utilized to reach the results of this evaluation. Results were based on historical oil, gas and water production information, geological maps, logs and offsetting lease analogies. The evaluation is based on information provided by the company. Data such as production rates, lease operating costs, ownership interests and projections for future activities were relied on to be true. In all cases PEI has reviewed the data to ensure reasonable values, consistency and dependability.

OPERATIONS

This evaluation covers the company operation in Kingfisher, Logan Johnston and Garfield Counties, OK. The three projects within these counties are known as Chisholm, Cimarron and Viking. TER participated in the projects as a non-operator, with the operation conducted by Husky Ventures.

Production is from the Paleozoic age Hunton Group. The Hunton is a well-known oil and gas producing formation, and recently has been developed by drilling horizontal wells. The vertical depth to the target is approximately 8,000 feet and the horizontal section may reach 4,000 feet for a total well length of 12,000 feet. Spacing of 160 acres per well are anticipated in the future. The typical initial rate of production is between 4,000 and 9,000 barrels of oil per month followed by a steep decline which gradually levels off. As a result of the natural fracing initial water production is high but quickly drops off. There was minor value attributable to the Bromide formation producing wells.

Twenty three wells were producing and one well was non-producing as of the end of 2014. The number of additional drilling locations is estimated to exceed seventy two, but only fifty eight wells were considered as economical proved undeveloped for this evaluation. In addition, the area contains other potential producing horizons, but due to the lack of information no value was attributed to these zones.

PRODUCTS PRICE The twelve months unweighted average of first day of the month NYMEX prices for oil and gas were used in calculating the 2014 average price resulting in $4.35/MMBtu and $91.48/Bbl.

Oil and gas price differentials were provided by TER and utilized in this evaluation. The average oil and gas prices were held constant throughout the economic life of the leases. It should be noted that gas production from the Hunton formation contains high heating value (BTU) and contains natural gas liquids. The gas is processed in plants which remove the liquids. The liquids are sold separately under sales agreements that contains sharing of revenue. The net result of the revenue generated from liquids sales were added to the residual gas sales and the combined value is reflected as an increase in the heating value and price fees. Each lease was evaluated separately. However, the products prices for the proved undeveloped leases were based on the average value of the producing wells. Individual monthly run sheets were made available by TER.

OPERATING EXPENSES and CAPITAL COSTS reccurring lease operating expenses were provided by the company and accepted when seemed reasonable for the type of operation and area. Lease operating expenses were held constant throughout the life of the reserve. The operating costs were split between operating expenses and water disposal costs and were calculated on a lease by lease basis. Future capital costs were held constant at the 2014 year expenditures level. Abandonment cost was included for each well. Drilling and completion costs were based on Authorization For Expenditure ("AFE") data provided by the company. The company provided assurances that all capital requirements will be met. Fifteen of the PUD locations reported in the 2013 year-end report were drilled in 2014 and were producing.

TAXES

Production and ad valorem taxes were based on the Oklahoma rates, including a tax reduction to 1.2% of revenue for the first 48 months.

Hedge values were not considered in this evaluation.

Note that oil and gas reserves as well as gross and net revenues are ESTIMATES that may change as additional production data becomes available or prices change. All estimates are subject to change due to the inherent uncertainty in the application of judgmental factors as well as regulatory environment.

PEI did not physically visit any of the fields, PEI accepted as true all ownership interests. PEI has not evaluated any potential environmental liability. PEI does not own economic interest in any of the company's assets.

AS OF DECEMBER 31, 2014

	PROVED DEVELOPED				PROVED UNDEVELOPED	
	PRODUCING		NON PRODUCING			
	OIL, MB	GAS, MMCF	OIL, MB	GAS, MMCF	OIL, MB	GAS, MMCF
GROSS RESERVES	1,596	12,379	78	851	7,579	44,849
NET RESERVES	67	488	18	199	481	3,104

Values of proved reserves in this report are expressed in terms of ESTIMATED future gross revenue, future net revenue, and present worth using a discount factor of 10%. Future gross revenue is the revenue which will accrue to the appraised interests from production and sale of the estimated net reserves. Net revenue is the gross revenue less production and ad valorem taxes, operating expenses and capital costs. Operating expenses include direct field expenses but exclude general administration costs. Federal income tax was not included in this analysis.

AS OF DECEMBER 31, 2014

	PROVED DEVELOPED		PROVED
	PRODUCING	NON PRODUCING	UNDEVELOPED
FUTURE GROSS INCOME, M$	9,000	2,880	63,184
PRODUCTION & ADVALOREM TAX, M$	319	93	2,674
OPERATING EXPENSE, M$	2,381	586	12,552
CAPITAL COST, M$	-	-	22,469
FUTURE NET REVENUE, M$	6,300	2,201	25,489
PRESENT VALUE DISC AT 10%, M$	4,741	1,781	12,517

Submitted,

STATE OF TEXAS
AMIEL DAVID
50970
REGISTERED
PROFESSIONAL ENGINEER

Amiel David, P.E. #50970

For PeTech Enterprises, Inc. Registrat