VICTORY ENERGY CORP
Form 10-K
April 08, 2016

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 10-K

ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2015

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

For the transition period from ____________ to _____________

Commission file number: 002-76219-NY
VICTORY ENERGY CORPORATION
(Exact name of registrant as specified in its charter)

Nevada	87-0564472
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
3355 Bee Caves Road, Suite 608, Austin, Texas	78746
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: 512-347-7300

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

Securities registered pursuant to Section 12(g) of the Act: Common Stock, $0.001 par value (Title of class)

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

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 ý

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 registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No o

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

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

Large Accelerated Filer	o	Accelerated Filer	o
Non-Accelerated Filer (do not check if Smaller Reporting Company)	o	Smaller Reporting Company	ý

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

The aggregate market value of the voting common equity held by non-affiliates of the registrant, computed by reference to the closing price of such stock on June 30, 2015 was approximately $5,246,281 based on the closing price of such stock and such date of $0.28.

The number of shares outstanding of the Registrant's common stock, $0.001 par value, as of April 8, 2016 was 31,220,326.

VICTORY ENERGY CORPORATION
ANNUAL REPORT ON

FORM 10-K
FOR THE YEAR ENDED December 31, 2015

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Cautionary Notice Regarding Forward Looking Statements

We desire to take advantage of the “safe harbor” provisions of the Private Securities Litigation Reform Act of 1995. This report contains a number of forward-looking statements that reflect management's current views and expectations with respect to business, strategies, future results and events and financial performance. All statements made in this Annual Report on Form 10-K other than statements of historical fact, including statements that address operating performance, events or developments that management expects or anticipates will or may occur in the future, including statements related to revenues, cash flow, profitability, adequacy of funds from operations, statements expressing general optimism about future operating results and non-historical information, are forward looking statements. In particular, the words “believe,” “expect,” “intend,” “anticipate,” “estimate,” “may,” “will,” variations of such wo and similar expressions identify forward-looking statements, but are not the exclusive means of identifying such statements and their absence does not mean that the statement is not forward-looking.

Readers should not place undue reliance on these forward-looking statements, which are based on management’s current expectations and projections about future events, are not guarantees of future performance, are subject to risks, uncertainties and assumptions and apply only as of the date of this report. Our actual results, performance or achievements could differ materially from the results expressed in, or implied by, these forward-looking statements. In particular, our business, including our financial condition and results of operations and our ability to continue as a going concern may be impacted by a number of factors, including, but not limited to, the following:

- continued operating losses;
- our ability to continue as a going concern;
- our dependence on external sources of financing to operate our business and meet our debt service obligations;
- difficulties in raising additional capital;
- our inability to pay our accounts payable or our expenses as they arise;
- our inability to meet the required financial covenants of our lender;
- our inability to pay a preferred return to The Navitus Energy Group for new capital contributions to Aurora Energy Partners;
- challenges in growing our business;
- designation of our common stock as a “penny stock” under Securities and Exchange Commission, which we refer to as the SEC, regulations;
- FINRA requirements that may limit the ability to buy and sell our common stock;
- illiquidity and price volatility of our common stock;
- the highly speculative nature of an investment in our common stock;
- climate change and greenhouse gas regulations;
- global economic conditions;
- the substantial amount of capital required by our operations;
- the volatility of oil and natural gas prices;
- the high level of risk associated with drilling for and producing oil and natural gas;
- assumptions associated with reserve estimates;

- the potential that drilling activities will not yield oil or natural gas in commercial quantities;
- potential exploration, production and acquisitions may not maintain revenue levels in the future;
- our acquisition of additional oil and natural gas assets in the Permian Basin and other future acquisitions may yield revenues or production that differ significantly from our projections;
- we may expend significant resources on potential acquisitions or other projects that fail to consummate;
- difficulties associated with managing a small and growing enterprise;
- strong competition from other oil and natural gas companies;
- the unavailability or high cost of drilling rigs and related equipment;
- our inability to control properties that we do not operate;
- our dependence on third parties for the marketing of our crude oil and natural gas production;
- our dependence on key management personnel and technical experts;
- our inability to keep pace with technological advancements in our industry;
- the potential for write-downs in the carrying values of our oil and natural gas properties;
- our compliance with complex laws governing our business;
- our failure to comply with environmental laws and regulations;
- the demand for oil and natural gas and our ability to transport our production;
- the financial condition of the operators of the properties in which we own an interest;
- the dilutive effect of additional issuances of our common stock, options or warrants;
- any impairments of our oil and natural gas properties;
- the results of pending litigation.

PART I
Item 1. Business

The Company

We are an independent, growth-oriented exploration and production company, headquartered in Austin, Texas, with additional technical and specialized resources located in Midland, Texas.

We were organized under the laws of the State of Nevada on January 7, 1982. We are authorized to issue 47,500,000 shares of common stock par value $0.001 per share. On January 12, 2012 we implemented a 50:1 reverse stock split of our common stock. All information in this Annual Report on Form 10-K reflects the effect of the reverse stock split.

Prior to May 3, 2006 we operated under the name Victory Capital Holdings Corporation among other corporate names.

The terms "Victory", "Company", "we", our", and "us" refer to Victory Energy Corporation and our consolidated subsidiaries unless the context suggests otherwise.

Our Relationship with Aurora Energy Partners

We are the managing partner of Aurora Energy Partners, a Texas general partnership that we refer to as Aurora, and we hold a 50% partnership interest in Aurora. Aurora is our consolidated subsidiary for financial statement purposes. The Second Amended Partnership Agreement of Aurora, which we refer to as the Aurora Partnership Agreement, gives us control over Aurora. Article XI of the Aurora Partnership Agreement cannot be modified without the approval of all (100%) of the partners of Aurora; therefore, we cannot be removed as a managing member of Aurora regardless of the percentage partnership interest held by the other partners of Aurora. Accordingly, consolidation is appropriate for all reporting periods. We currently conduct all of our oil and natural gas operations through, and hold all of our oil and natural gas assets through, Aurora. Aurora is the record title holder to substantially all of the oil and natural gas properties, wells and reserves referred to in this annual report. Through our partnership interest in Aurora, we are the beneficial owner of 50% of the oil and gas properties, wells and reserves held of record by Aurora.

Operational Overview and Strategy

We are independent growth-oriented oil and gas exploration and production company based in Austin, Texas, with additional resources located in Midland, Texas. The company has historically been focused on the acquisition and development of unconventional resource play opportunities in the Permian Basin, the Eagle Ford shale of South Texas and other strategically important areas that offer predictable economic outcomes and long-lived reserve characteristics, however we will also pursue opportunistic acquisition in other areas of the country. The current company asset portfolio includes both vertical and horizontal wells in prominent formations such as the Eagle Ford, Austin Chalk, Woodbine, Spraberry, Wolfcamp, Wolfberry, Mississippian, Cline, Fusselman and Ellenberger. We are focused on creating shareholder value by rapidly growing conventional oil and liquids-rich natural gas reserves and cash-flow via continued low-risk vertical well development on existing properties, as well as through the acquisition of new economically strong producing properties. This focus on returns is achieved by targeting predictable conventional and resources plays that provide favorable operating environments and lifting costs.
We have carefully assembled a management team with more than 130 years of direct and relevant oil and gas experience, who also hold extensive industry relationships to help grow the company. We also utilize a team of third-party professionals on an as-needed basis. This team includes geologists for prospect evaluation and assessment and reservoir engineering resources for the analysis of current and new properties. Reserve reporting is performed by a third-party engineer located in Midland, Texas. Each independent operator utilized by the company also has their own array of experts tailored for the specific formations and well completion techniques of each property the Company

holds an interest in. We strategically utilize both internal capabilities and strategic industry relationships to acquire non-operated, high-grade working interest positions in predictable, low-to-moderate risk oil and gas prospects. To help grow the company and lower field level operating expenses, we also plan to build-out an internal operating team in the near-future.

Our common stock is quoted under the ticker symbol VYEY on the OTCQB, operated by OTC Markets Group.
We are one of two partners in Aurora which was established in January 2008. The second partner in Aurora is the Navitus Energy Group, which we refer to as Navitus. Navitus is also a Texas general partnership. Navitus and our company work together to

increase proved reserves and the valuation of Aurora. We plan to eventually consolidate 100% of the ownership of Aurora under Victory and thereafter move to a national securities exchange such as the NYSE or NASDAQ.
Navitus Partners, LLC, a partner in the Navitus general partnership, is currently seeking to raise up to $15 million of capital for contribution through Navitus to the Aurora partnership . The net proceeds of this offeringwill generally be used to fund Aurora's operations, as well as for the potential acquisition and development of targeted oil and gas opportunities . The investors in this offering will receive a 10% preferred return through their indirect interest in the Navitus partnership for five yearsand one warrant to purchase one share of Victory common stock for every dollar invested and additional benefits. Under the terms of the offering Navitus has the right to contribute up to $15 million into Aurora and Victory is obligated to match the capital contribution amount of Navitus resulting from the offering. Victory is also required to match previous contributions made by Navitus. Under the agreement, separation of the partners is not mandatory and Victory may raise funds from other sources. Substantially all producing oil and natural gas assets are held in the Aurora partnership during the five year term of the Aurora Partnership Agreement which ends in October 2017. As of December 31, 2015, Navitus has contributed $7.3 million into Aurora.
As of December 31, 2015, we had 37 gross wells on production. Our portfolio of producing assets now includes the following properties: the Eagle Ford Property, the Fairway property, the Bootleg Canyon Ellenberger Field, the Adams-Baggett Gas Field, the Morgan property, the Uno-Mas property and the Clear Water Wolfberry resource property. Proved commercial accumulations of hydrocarbons now occur in multiple horizons, at depths ranging from 4,700 to 13,100 feet, with the majority of proved reserves being located on properties in the Permian Basin of Texas and New Mexico.
As we continue to evaluate available locations on our current properties and add properties that are accessible to us through our established deal flow pipeline, we anticipate an accelerated pace toward oil-weighted production and the addition of new reserves. Due to the precipitous downturn in oil prices in the later part of 2014 continuing through 2015, we are concentrating our efforts on attractive acquisitions of proved producing properties.
Our capital and exploration expenditures totaled $1,058,704 for the year ended December 31, 2015. At December 31, 2015, we had $2,384 of cash on hand with $680,000 outstanding under our credit facility with Texas Capital Bank, National Association. Cash on hand is generally kept low because of our ability to acquire capital funding, when needed via our Aurora partner Navitus Energy Group. The credit facility was classified as currently payable due to the failure to meet the current ratio covenant set forth in the credit facility at December 31, 2015. We are currently in default under our credit facility with Texas Capital Bank and have entered into a forbearance agreement with Texas Capital Bank. See Risk Factors - "We have defaulted under our Credit Agreement with Texas Capital Bank, which we refer to as our Lender. Although our Lender has agreed to forbear all existing events of default, if we do not cure our defaults or otherwise satisfy our obligations under the Credit Agreement, the Lender could foreclose resulting in a material adverse effect on our financial condition and ability to operate and our stock could lose significant or all of its value."

Navitus contributed $2,917,000 in cash to Aurora for the year ended December 31, 2015, and $1,140,000 for the year ended December 31, 2014. Distributions to Navitus were deferred for the year ended December 31, 2015, while distributions to Navitus totaled $647,421 for the year ended December 31, 2014.

Terminated Business Combination with Lucas

On February 4, 2015, Victory entered into a letter of intent relating to a proposed business combination with Lucas Energy, Inc., which we refer to as Lucas. Thereafter, Victory, Lucas and certain other parties entered into certain collaboration and loan and funding agreements, which we refer to as the Lucas Transaction Documents, but the parties never entered into a definitive merger agreement. Pursuant to the Lucas Transaction Documents we loaned Lucas a total of $600,000 through May 11, 2015, the date that we terminated the letter of intent and Lucas Transaction Documents.
Merger and merger termination related direct costs total $1,344,812 and are included in general and administrative expenses for the twelve months ended December 31, 2015.

On June 24, 2015, we entered into (1) a Settlement Agreement and Mutual Release with Lucas, which we refer to as the Lucas Settlement Agreement, (2) a Settlement Agreement and Mutual Release with Louise H. Rogers, which we refer to as the Rogers Settlement Agreement, and (3) a Compromise Settlement Agreement and Mutual General Release, effective as of June 25, 2015 with Earthstone Operating, LLC, Earthstone Energy, Inc., Oak Valley Resources, LLC, Oak Valley Operating LLC and Sabine River Energy, LLC, Lucas, AEP, and Aurora, which we refer to as the Earthstone Settlement Agreement.

Lucas Settlement Agreement

Pursuant to the Lucas Settlement Agreement, we agreed with Lucas to terminate any and all obligations between the parties arising under the letter of intent and Lucas Transaction Documents. We further agreed that we would retain ownership and control over five Penn Virginia well-bores previously assigned by Lucas to us, which we refer to as the Penn Virginia Well-Bores, as well as the obligations to pay the expenses associated with such Penn Virginia Well-Bores effective after August 1, 2014. Under the terms of the Lucas Settlement Agreement, Lucas agreed to assign to us all of Lucas' rights in a certain oil and gas property located in the same field as the Penn Virginia Well-Bores, which we refer to as the "Additional Penn Virginia Property", including the rights to all revenues from all wells on some properties. Lucas acknowledged the principal amount of $600,000 previously advanced to Lucas by us and agreed that we have no further obligations to advance any additional funds to Lucas pursuant to the terms of the Loan Agreement. Pursuant to the terms of the Lucas Settlement Agreement, Lucas agreed to issue 1,101,729 shares (44,069 post-split declared by Lucas as of July 15, 2015) of its common stock, which we refer to as the Settlement Shares to us in full consideration of the $600,000 owed to us. The Settlement Shares and an assignment of the Additional Penn Virginia Property were held in escrow pending the payment by us of amounts owed to Rogers under the Rogers Settlement (as described below). We charged the $600,000 to general and administrative expenses as a cost of the merger termination.

Rogers Settlement Agreement

Pursuant to the Rogers Settlement Agreement, we agreed with Rogers, among other things, (i) to terminate the contingent promissory note in the principal amount of $250,000 payable to Rogers that was issued by Victory in connection with the entry by Lucas and Victory into the Lucas Transaction Documents, (ii) that we would pay Rogers, on or before July 15, 2015, $253,750, and (iii) that Rogers' legal counsel will hold the assignment of the Additional Penn Virginia Property and the Settlement Shares in escrow until such time as the payment of $253,750 is made by us to the Rogers.

Amendment to Rogers Settlement Agreement

On July 16, 2015, we entered into an Amendment to the Rogers Settlement Agreement. Pursuant to the amendment, we agreed with Rogers that the amount to be paid by us to Rogers under the Rogers Settlement Agreement is $258,125, instead of $253,750. The Amendment further specified that if we failed to make the payment of $258,125 on or before July 15, 2015, we would be in default under the Rogers Settlement Agreement and default interest on the amount due would begin to accrue at a per diem rate of $129.0625. Additionally, we acknowledged in the Amendment our obligation to pay Rogers' attorney's fees in the amount of $22,500. As of the date of this annual report, we have not made any payments to Rogers pursuant to the Rogers Settlement Agreement.

As described above, Rogers' legal counsel held the assignment to us of Lucas' rights to the Additional Penn Virginia Property and the Settlement Shares in escrow pending our payment of all amounts due under the Rogers Settlement Agreement. The amount due under the amendment totaled $285,546 through August 17, 2015. We failed to make the required payment to Rogers by August 27, 2015, and have still not made all the required payments. As a result, the Additional Penn Virginia Property was returned to Lucas on or about September 3, 2015. The full amount due to Rogers including accrued interest at December 31, 2015 totals $300,432.

Earthstone Settlement Agreement

Pursuant to the terms of the Earthstone Settlement Agreement, we assigned to Earthstone certain oil and gas interests in well site locations which were previously transferred to us by Lucas in February 2015. We agreed with Earthstone to release each other from any and all claims one party may have against the other prior to the effective date of the Earthstone Settlement Agreement, except for claims arising under the Earthstone Settlement Agreement. Lucas and Earthstone similarly agreed to release each other from such claims pursuant to the terms of the Earthstone Settlement Agreement.

We charged the $195,928 payment made to Earthstone in February 2015, to general and administrative expenses as a cost of the merger termination.

Distribution Methods

Each of our fields that produce oil distributes the oil through one purchaser for each field. There is significant demand for oil and there are several companies in our operating areas that purchase oil from small oil producers.

Each of our fields that produce natural gas distributes all of the natural gas that it produces through one purchaser for each field. We have distribution agreements with these natural gas purchasers that provide us a tap into a distribution line of a natural gas distribution company. We are to be paid for our natural gas at either a market price at the beginning of the month or market price at the time of delivery, less any transportation cost charged by the natural gas distribution company.

Competition

We encounter competition from other oil and natural gas companies in all areas of our operations. Many of our competitors are large, well-established companies that have been engaged in the oil and natural gas business for much longer than we have and possess substantially larger operating staffs and greater capital resources than we do. We compete by leveraging our experience and hands on knowledge of the marketplace of available properties for sale and/or development.

Source and Availability of Raw Materials

We have no significant raw materials. However, we make use of numerous oil field service companies in the drilling and work over of wells. We currently operate in areas where there are numerous oil field service and drilling companies that are available to us.

Marketing Arrangements

There is a ready market for the sale of oil and gas. Each of our fields currently sells all of its oil and gas production on the spot market basis.

Federal Regulations

Our business is subject to federal, state and local laws, regulations, and other legal requirements enacted by governmental authorities, including regulations related to the operation of wells, pricing and terms for access to pipeline transportation, and environmental matters. Compliance with these provisions has not had any material adverse effect upon our capital expenditures, net earnings or competitive position. However, the legislative and regulatory burden placed on the industry raises our cost of doing business and therefore could impact profitability. Please refer to Item 1A, Risk Factors.

Regulation of Sale and Transportation of Natural Gas

The transportation and sale for resale of natural gas in interstate commerce are regulated pursuant to the Natural Gas Act of 1938, which we refer to as the NGA, and the Natural Gas Policy Act of 1978. These statutes are administered by the Federal Energy Regulatory Commission, which we refer to as FERC. Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act of 1989 deregulated natural gas prices for all “first sales” of natural gas, which includes all sales by us of our own production. All other sales are subject to a blanket sales certificate under the NGA, which has flexible terms and conditions. Consequently, all of our sales of natural gas currently may be made at market prices, subject to applicable contract provisions. Our jurisdictional sales, however, are subject to the future possibility of greater federal oversight, including the possibility that the FERC might prospectively impose more restrictive conditions on such sales. Conversely, sales of crude oil and condensate and natural gas liquids by us are made at unregulated market prices.

Thus, all of our sales of natural gas may be made at market prices, subject to applicable contract provisions. Sales of natural gas are affected by availability, terms and cost of pipeline transportation. Since 1985, FERC has implemented regulations intended to make natural gas transportation more accessible to gas buyers and sellers on an open access, non-discriminatory basis. We cannot predict what further action FERC will take on these matters. Some of FERC’s more recent proposals may, however, adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any action taken materially differently than other natural gas producers, gatherers and marketers with which we compete.

Our natural gas sales are generally made at the prevailing market price at the time of sale. Therefore, even though we sell significant volumes to major purchasers, we believe that other purchasers would be willing to buy our natural gas at comparable market prices.

Natural gas continues to supply a significant portion of North America's energy needs and we believe the importance of natural gas in meeting this energy need will continue. The impact of the ongoing economic downturn on natural gas supply and demand fundamentals has resulted in extremely volatile natural gas prices, which is expected to continue.

On August 8, 2005, the Energy Policy Act of 2005, which we refer to as the 2005 EPA, was signed into law. This comprehensive act contains many provisions that will encourage oil and natural gas exploration and development in the United States. The 2005 EPA directs FERC and other federal agencies to issue regulations that will further the goals set out in the 2005 EPA. The 2005 EPA amends the NGA to make it unlawful for "any entity," including otherwise non-jurisdictional producers such as us, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by FERC, in contravention of rules prescribed by FERC. On January 20, 2006, FERC issued rules implementing this provision. The rules make it unlawful in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. The new anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of otherwise non-jurisdictional entities to the extent the activities are conducted “in connection with” gas sales, purchases or transportation subject to FERC jurisdiction. It therefore reflects a significant expansion of FERC’s enforcement authority. We do not believe that we are affected any differently than other producers of natural gas.

In 2007, FERC issued a final rule on annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing, which we refer to as Order 704. Under Order 704, wholesale buyers and sellers of more than 2.2 million MBtu of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors and natural gas marketers are now required to report, on May 1 of each year, beginning in 2009, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. The monitoring and reporting required by these rules have increased our general and administrative expenses. We do not anticipate that we will be affected any differently than other producers of natural gas.

Regulation of the Sale and Transportation of Oil

Our sales of crude oil, condensate and NGL are not currently regulated, and are subject only to applicable contract provisions negotiated by us and our counterparties. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to FERC’s jurisdiction under the Interstate Commerce Act, which we refer to as the ICA. In other instances, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to regulation by state regulatory bodies under state statutes.

The regulation of pipelines that transport oil, condensate and NGL is generally less restrictive than FERC’s regulation of natural gas pipelines under the NGA. Regulated pipelines that transport crude oil, condensate and NGL are subject to common carrier obligations that generally ensure non-discriminatory access. With respect to interstate pipeline transportation subject to regulation of FERC under the ICA, rates generally must be cost-based, although market-based rates or negotiated settlement rates are permitted in certain circumstances. Pursuant to FERC Order No. 561, pipeline rates are subject to an indexing methodology. Under this indexing methodology, pipeline rates are subject to changes in the Producer Price Index for Finished Goods, minus 1%. A pipeline can seek to increase its rates above index levels provided that the pipeline can establish that there is a substantial divergence between the actual costs experienced by the pipeline and the rate resulting from application of the index. A pipeline can seek to charge market based rates if it establishes that it lacks significant market power. In addition, a pipeline can establish rates pursuant to settlement if agreed upon by all current shippers. A pipeline can seek to establish initial rates for new services through a cost-of-service proceeding, a market-based rate proceeding, or through an agreement between the pipeline and at least one shipper not affiliated with the pipeline.

Federal, State or American Indian Leases. In the event we conduct operations on federal, state or American Indian onshore oil and natural gas leases, such operations must comply with numerous regulatory restrictions, including various nondiscrimination statutes, certain on-site security regulations and must also obtain permits issued by the

Bureau of Land Management, which we refer to as the BLM, or other appropriate federal, tribal or state agencies.

The Mineral Leasing Act of 1920, which we refer to as the Mineral Act, prohibits direct or indirect ownership of any interest in federal onshore oil and natural gas leases by a foreign citizen of a country that denies “similar or like privileges” to citizens of the United States. Such restrictions on citizens of a “non-reciprocal” country include ownership or holding or controlling stock in a corporation that holds a federal onshore oil and natural gas lease. If this restriction is violated, the corporation’s lease can be canceled in a proceeding instituted by the United States Attorney General. Although the regulations of the BLM (which administers the Mineral Act) provide for agency designations of non-reciprocal countries, there are presently no such designations in effect. We own interests in numerous federal onshore oil and natural gas leases. It is possible that holders of our equity interests may be citizens of foreign countries, which at some time in the future might be determined to be non-reciprocal under the Mineral Act. If any of our equity holders is deemed to be a citizen of a non-reciprocal country, then our interests in federal onshore oil and natural gas leases may be canceled. Any such cancellation could have a material adverse effect on our financial condition, cash flows and results of operations.

State Regulations

Most states regulate the production and sale of oil and natural gas, including:

- requirements for obtaining drilling permits;
- the method of developing new fields;
- the spacing and operation of wells;
- the prevention of waste of oil and gas resources; and
- the plugging and abandonment of wells.

The rate of production may be regulated and the maximum daily production allowable from both oil and natural gas wells may be established on a market demand or conservation basis or both.

We may enter into agreements relating to the construction or operation of a pipeline system for the transportation of natural gas. To the extent that such natural gas is produced, transported and consumed wholly within one state, such operations may, in certain instances, be subject to the jurisdiction of such state's administrative authority charged with the responsibility of regulating intrastate pipelines. In such event, the rates that we could charge for natural gas, the transportation of natural gas, and the construction and operation of such pipeline would be subject to the rules and regulations governing such matters, if any, of such administrative authority.

Environmental, Health and Safety Regulation

General. Our activities are subject to existing federal, state and local laws and regulations governing environmental quality and pollution control. Although no assurances can be made, we believe that, absent the occurrence of an extraordinary event, compliance with existing federal, state and local laws, regulations and rules regulating the release of materials in the environment or otherwise relating to the protection of human health, safety and the environment will not have a material effect upon our capital expenditures, earnings or competitive position with respect to our existing assets and operations. We cannot predict what effect additional regulation or legislation, enforcement policies, and claims for damages to property, employees, other persons and the environment resulting from our operations could have on our activities.

Our activities with respect to exploration and production of oil and natural gas, including the drilling of wells, are subject to stringent environmental regulation by state and federal authorities, including the U.S. Environmental Protection Agency, which we refer to as the US EPA. Such regulations can increase the cost of our activities. Although we believe that compliance with environmental regulations will not have a material adverse effect on us, risks of substantial costs and liabilities are inherent in oil and natural gas production operations, and there can be no assurance that significant costs and liabilities will not be incurred. Moreover it is possible that other developments, such as spills or other unanticipated releases, stricter environmental laws and regulations, and claims for damages to property or persons resulting from oil and natural gas production, would result in substantial costs and liabilities to us.

Solid and Hazardous Waste. We own or lease numerous properties that have been used for production of oil and natural gas for many years. Although we have utilized operating and disposal practices standard in the industry at the time, hydrocarbons or other solid wastes may have been disposed of or released on, under, or from these properties. In addition, many of these properties have been operated by third parties that controlled the treatment of hydrocarbons and solid wastes and the manner in which such substances may have been disposed or released. State and federal laws applicable to oil and natural gas wastes and properties have gradually become stricter over time. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators) or to perform remedial plugging operations to prevent future contamination.

We generate wastes, including hazardous wastes, which are subject to regulation under the federal Resource Conservation and Recovery Act, which we refer to as the RCRA, and state statutes. The USEPA has limited the disposal options for certain hazardous wastes. Furthermore, it is possible that certain wastes generated by our oil and natural gas operations that are currently exempt from regulation as “hazardous wastes” may in the future become regulated as “hazardous wastes” under RCRA or other applicable statutes, and therefore may become subject to more rigorous and costly management and disposal requirements.

Naturally Occurring Radioactive Materials, which we refer to as NORM, are radioactive materials which precipitate on production equipment or area soils during oil and natural gas extraction or processing. NORM wastes are regulated under the RCRA framework, although such wastes may qualify for the oil and gas hazardous waste exclusion. Primary responsibility for NORM regulation has been a state function. Standards have been developed for worker protection; treatment, storage and disposal of NORM waste;

management of waste piles, containers and tanks; and limitations upon the release of NORM-contaminated land for unrestricted use. We believe that our operations are in material compliance with all applicable NORM standards.

Superfund. The Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, which we refer to as CERCLA, also known as the "Superfund" law, imposes joint and several liabilities, without regard to fault or the legality of the original conduct of certain persons with respect to the release or threatened release of a "hazardous substance" into the environment. These persons include the current or former owner or and operator of the site where the release occurred and anyone who and persons that disposed or arranged for the disposal of a hazardous substance to the site where the release occurred. Under CERCLA, such persons may be subject to joint and several liabilities for the costs of cleaning up the hazardous substances that have been released into the environment, damages to natural resources and the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

We own and lease, and may in the future operate, numerous properties that have been used for oil and natural gas exploitation and production for many years. Hazardous substances may have been released on, at or under the properties owned, leased or operated by us, or on, at or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been or are operated by a site. CERCLA also authorizes the USEPA and, in some cases, third parties or by previous owners or operators whose handling, treatment and disposal of hazardous substances were not under our control. These properties and the substances disposed or released on, at or under them may be subject to CERCLA, RCRA and analogous state laws. In certain circumstances, we could be responsible for the removal of previously disposed substances and wastes, remediate contaminated property or perform remedial plugging or pit closure operations to prevent future contamination. In addition, federal and state trustees can also seek substantial compensation for damages to natural resources resulting from spills or releases.

Water discharges. The Federal Water Pollution Control Act, which we refer to as the Clean Water Act, and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including oil and other substances generated by our operations, into waters of the United States or state waters. Under these laws, the discharge of pollutants into regulated waters is prohibited except in accordance with the terms of a permit issued by EPA or an analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

The Safe Drinking Water Act, which we refer to as SDWA, and analogous state laws impose requirements relating to underground injection activities. Under these laws, the EPA and state environmental agencies have adopted regulations relating to permitting, testing, monitoring, record keeping and reporting of injection well activities, as well as prohibitions against the migration of injected fluids into underground sources of drinking water.

Air emissions. The Federal Clean Air Act and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, EPA and certain states have developed and continue to develop stringent regulations governing emissions of toxic air pollutants at specified sources. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the Federal Clean Air Act and analogous state laws and regulations.

The Kyoto Protocol to the United Nations Framework Convention on Climate Change became effective in February 2005. Under the Protocol, participating nations are required to implement programs to reduce emissions of certain gases, generally referred to as greenhouse gases that are suspected of contributing to global warming. The United States is not currently a participant in the Protocol, and Congress has not acted upon recent proposed legislation directed at reducing greenhouse gas emissions. However, there has been support in various regions of the country for legislation that requires reductions in greenhouse gas emissions, and some states have already adopted legislation addressing greenhouse gas emissions from various sources, primarily power plants. The oil and natural gas industry is a direct source of certain greenhouse gas emissions, namely carbon dioxide and methane, and future restrictions on such emissions could impact our future operations.

National Environmental Policy Act. Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act, which we refer to as NEPA. NEPA requires federal agencies, including the Department of Interior, to evaluate major agency to take actions that have the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. All exploration and production activities on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of oil and natural gas projects on federal lands in response to threats to the public health or the environment and to seek to recover from the responsible persons the costs of such action. Certain state statutes impose similar liability. Neither we nor, to our knowledge, our predecessors have been designated as a potentially responsible party by the USEPA under CERCLA or by any state under a similar state law.

Health safety and disclosure regulation. Under CERCLA, the term “hazardous substance” does not include “petroleum, including crude oil or any fraction thereof,” unless specifically listed or designated and the term does not include natural gas, NGL, liquefied natural gas, or synthetic gas usable for fuel. While this “petroleum exclusion” lessens the significance of CERCLA to our operations, we may generate waste that may fall within CERCLA's definition of a “hazardous substance” in the course of our ordinary operations. We also currently own or lease properties that for many years have been used for the exploration and production of oil and natural gas. Although we and, to our knowledge, our predecessors have used operating and disposal practices that were standard in the industry at the time, “hazardous substances” may have been disposed or released on, under or from the properties owned or leased by us or on, under or from other locations where these wastes have been taken for disposal. At this time, we do not believe that we have any liability associated with any Superfund site, and we have not been notified of any claim, liability or damages under CERCLA.

Oil Pollution Act. The Oil Pollution Act of 1990, which we refer to as the OPA, and regulations thereunder impose a variety of regulations on “responsible parties” related to the prevention of oil spills and liability for damages resulting from such spills in certain United States waters. A “responsible party” includes the owner or operator of a facility or vessel, or the lessee or permittee of the area in which an offshore facility is located. The OPA assigns liability to each responsible party for oil removal costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if a spill was caused by gross negligence or willful misconduct or resulted from violation of federal safety, construction or operating regulations. If a party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by the OPA.

The OPA currently establishes a liability limit for onshore facilities of $350 million and for offshore facilities of all removal costs plus $75 million, and lesser limits for some vessels depending upon their size. The regulations promulgated under OPA impose proof of financial responsibility requirements that can be satisfied through insurance, guarantee, indemnity, surety bond, letter of credit, qualification as a self-insurer, or a combination thereof. The amount of financial responsibility required depends upon a variety of factors including the type of facility or vessel, its size, storage capacity, oil throughput, proximity to sensitive areas, type of oil handled, history of discharges and other factors. We carry insurance coverage to meet these obligations, which we believe is customary for comparable companies in our industry. A failure to comply with OPA's requirements or inadequate cooperation during a spill response action may subject a responsible party to civil or criminal enforcement actions.

Clean Water Act. The Clean Water Act, which we refer to as the CWA, regulates the discharge of pollutants into waters of the United States and adjoining shorelines, including wetlands, and requires a permit for the discharge of pollutants, including petroleum and dredged or fill materials, into such waters and wetlands. Certain state regulations and the general permits issued under the federal National Pollutant Discharge Elimination System program prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry operations into certain coastal and offshore waters. Further, the USEPA has adopted regulations requiring certain facilities that store or otherwise handle oil to prepare and implement Spill Prevention, Control and Countermeasure Plans and Facility Response Plans relating to the possible discharge of oil to surface waters. We are required to prepare and comply with such plans and to obtain and comply with discharge permits. The CWA also prohibits spills of oil and hazardous substances to waters of the United States in excess of levels set by regulations and imposes liability in the event of a spill. State laws further provide civil and criminal penalties and liabilities for spills to both surface and groundwater and require permits that set limits on discharges to such waters. We believe we are in substantial compliance with these requirements and that any noncompliance would not have a material adverse effect on us.

Safe Drinking Water Act. The underground injection of oil and natural gas wastes is regulated by the Underground Injection Control (“UIC”) Program, authorized by the federal SDWA. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. In Oklahoma, Louisiana, Mississippi and Texas, no underground injection may take place except as authorized by permit or rule. We currently own and operate various underground injection wells. Failure to comply with our permits could subject us to civil and/or criminal enforcement. We believe that we are in compliance in all material respects with the requirements of applicable state underground injection control programs and our permits and authorizations.

Moreover, our exploration and production activities may involve the use of hydraulic fracturing techniques to stimulate wells and maximize natural gas production. Citing concerns over the potential for hydraulic fracturing to impact drinking water, human health and the environment, and in response to a congressional directive, the USEPA has commissioned a study to identify potential risks associated with hydraulic fracturing. The USEPA published a progress report on this study in December 2012 and a final draft report will be delivered in 2014. Additionally, the BLM proposed to regulate the use of hydraulic fracturing on federal and tribal lands, but following extensive public comment on the proposals, announced it would issue an improved proposal before finalizing new rules. The revised proposal is expected to address disclosure of fluids used in the fracturing process, integrity of well construction, and the management and disposal of wastewater that flows back from the drilling process. Some states now regulate utilization of hydraulic fracturing and others are in the process of developing, or are considering development of, such rules. Depending on the results of the USEPA study and other developments related to the impact of hydraulic fracturing, our drilling activities could be subjected to new or enhanced federal, state and/or local regulatory requirements governing hydraulic fracturing.

Air Emissions. Our operations are subject to local, state and federal regulations for the control of emissions from sources of air pollution. The USEPA has promulgated new rules to address air emissions from the oil and natural gas industry which, among other things, would require installation of equipment to capture certain gases released from new or refitted hydraulically fractured natural gas wells by January 1, 2015. Other new rules, many effective in 2012, impose stricter standards on emissions associated with gas production, storage and transport. The proposals would revise New Source Performance Standards for volatile organic compounds and sulfur dioxide, impose controls on toxics emitted at oil and natural gas wells and their associated production facilities, and limit fugitive emissions from the production, storage and transport equipment. In addition, states impose requirements to address emissions from certain production and associated facilities. We have complied and will continue to comply with these regulations as applicable to our operations. Due to the uncertainties surrounding proposed regulations, we are unable to predict the financial impact going forward.

Administrative enforcement actions for failure to comply strictly with air regulations or permits may be resolved by payment of monetary fines and/or correction of any identified deficiencies. Alternatively, civil and criminal liability can be imposed for non-compliance. Any such action could require us to forgo construction or operation of certain air emission sources. We believe that we are in substantial compliance with air pollution control requirements and that, if a particular permit application were denied, we would have enough permitted or permittable capacity to continue our operations without a material adverse effect on any particular producing field.

Climate Change. According to certain scientific studies, emissions of carbon dioxide, methane, nitrous oxide and other gases commonly known as greenhouse gases, which we refer to as GHG, may be contributing to global warming of the earth's atmosphere and to global climate change. In response to the scientific studies, legislative and regulatory initiatives have been underway to limit GHG emissions. The U.S. Supreme Court determined that GHG emissions fall within the federal Clean Air Act, which we refer to as CAA, definition of an “air pollutant”, and in response the USEPA promulgated an endangerment finding paving the way for regulation of GHG emissions under the CAA. The USEPA has also promulgated rules requiring large sources to report their GHG emissions. Sources subject to these reporting requirements include on- and offshore petroleum and natural gas production and onshore natural gas processing and distribution facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year in aggregate emissions from all site sources. We are not subject to GHG reporting requirements. In addition, the USEPA promulgated rules that significantly increase the GHG emission threshold that would identify major stationary sources of GHG subject to CAA permitting programs. As currently written and based on current operations, we are not subject to federal GHG permitting requirements. Regulation of GHG emissions is new and highly controversial, and further regulatory, legislative and judicial developments are likely to occur. Such developments may affect how these GHG initiatives will impact us. Further, apart from these developments, recent judicial decisions that have not precluded certain state tort claims alleging property damage to proceed against GHG emissions sources may increase our litigation risk for such claims. Due to the uncertainties surrounding the regulation of and other risks associated with GHG emissions, we cannot predict the financial impact of related developments on us.

OSHA. We are subject to the requirements of the federal Occupational Safety and Health Act, which we refer to as OSHA, and comparable state statutes. The OSHA hazard communication standard, the Emergency Planning and Community Right to Know standards, the USEPA community right-to-know regulations under Title III of the federal Superfund Amendments and Reauthorization Act and similar state statutes require that we use to organize and/or disclose information about hazardous materials stored, used or produced in our operations. Certain of this information must be provided to employees, state and local governmental authorities and local citizens.

We expect to incur capital and other expenditures related to environmental compliance. Although we believe that our compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations, we cannot assure you that the passage of more stringent laws or regulations in the future will not have a negative impact on our financial position or results of operation.

Employees

We have four full-time employees as of December 31, 2015. We believe that our relationships with our employees are satisfactory. We utilize the services of independent contractors to perform various daily operational and administrative duties.

Available Information

We make available free of charge through our "Investor Center – SEC Filings" section of our webs-site at www.vyey.com our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other filings pursuant to Section 13(a) of the Securities Exchange Act of 1934, as amended, which we refer to as the Exchange Act, and the amendments to such filings, as soon as reasonably practicable after each are electronically filed with, or furnished to the SEC.

Glossary of Certain Industry Terms

The definitions set forth below shall apply to the indicated terms as used throughout this Annual Report on Form 10-K.

Bbl. One barrel (of oil or natural gas liquids).

BOE. One barrel of oil equivalent. A Boe is determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids, which approximates the relative energy content of oil, condensate and natural gas liquids as compared to natural gas. Despite holding this ratio constant at six Mcf to one Bbl, prices have historically often been higher or substantially higher for oil than natural gas on an energy equivalent basis, although there have been periods in which they have been lower or substantially lower.

Completion. Installation of permanent equipment for production of oil or gas, or, in the case of a dry well, to reporting to the appropriate authority that the well has been abandoned.

Developed acreage. The number of acres which are allocated or held by producing wells or wells capable of production.

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.

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

Exploratory well. 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 Regulation S-X.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Liquids. Describes oil, condensate, and natural gas liquids.

MBbls. Thousands of barrels of oil or natural gas liquids.

MBoe. Million barrels of oil equivalent.

Mcf. Thousand cubic feet (of natural gas).

MMcf. Million cubic feet.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or gross wells expressed in whole numbers.

NGL. Natural gas liquids.

Present value or PV10% or “SEC PV10%.” When used with respect to oil and gas reserves, present value or PV10% or SEC PV10% means the estimated future gross revenue to be generated from the production of net proved reserves, net of estimated production and future development and abandonment costs, using prices and costs under the SEC guideline at the balance sheet date, without giving effect to non-property related expenses such as general and administrative expenses, debt service, accretion, and future income tax expense or to depreciation, depletion, and amortization, discounted using monthly end-of-period discounting at a nominal discount rate of 10% per annum.

Productive wells. Producing wells and wells that are capable of production in sufficient quantities to justify completion, including injection wells, salt water disposal wells, service wells, and wells that are shut-in.

Proved developed reserves. Estimated proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved reserves. 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.

Proved undeveloped reserves. Estimated proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required.

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

Working Interest or WI. An operating interest which gives the owner the right to drill, produce, and conduct operating activities on the property and a share of production.

Item 1A. Risk Factors

Our business is subject to a number of risks including, but not limited to, those described below:

Risks Related to Our Business, Industry, and Strategy

Oil and gas prices are volatile and oil prices have been significantly depressed since the end of 2014. Declines in commodity prices have adversely affected, and in the future may adversely affect, our financial condition and results of operations, cash flows, access to the capital markets and ability to grow.

Our revenue reserves, cash flows, profitability and future rate of growth substantially depend upon the market prices of oil and natural gas. Our ability to borrow funds or obtain additional capital, as well as the carrying value of our properties, is substantially dependent on prevailing prices of oil and natural gas. Historically, the markets for oil and natural gas have been volatile, and those markets are likely to continue to be volatile in the future. Starting in the second half of 2014, the NYMEX price for a barrel of oil has fallen sharply. In addition, NYMEX prices for natural gas have been low compared with historical prices. Extended periods of low prices for oil or natural gas will have a material adverse effect on us, including the following possible negative effects:

- our cash flow will be reduced, which will decrease funds available for capital investments employed to replace reserves;
- certain reserves will no longer be economic to produce, resulting in lower proved reserves and cash flow and charges to earnings that impair the value of these assets; and
- access to other sources of capital, such as bank loans and equity or debt markets, could be severely limited or unavailable.

It is impossible to predict future oil and natural gas price movements with certainty.

The prices we receive for our oil and natural gas depend upon factors beyond our control, including, among others:

- changes in the supply of and demand for oil and natural gas;
- market uncertainty;
- level of consumer product demands;
- weather conditions;
- domestic governmental regulations and taxes; price and availability of alternative fuels;
- political and economic conditions in oil producing countries;

- actions by the Organization of Petroleum Exporting Countries;
- price of oil and natural gas imports; and
- overall domestic and foreign economic conditions.

These factors make it very difficult to predict future commodity price movements with any certainty. Substantially all of our oil and natural gas sales are made in the spot market or pursuant to contracts based on spot market prices and are not long-term fixed price contracts. Further, oil prices and gas prices do not necessarily fluctuate in direct relation to each other.

If oil and gas prices remain depressed for extended periods of time, we may be required to take additional write-downs of the carrying values of our oil and natural gas properties, which could negatively impacting the trading value of our securities.

Accounting rules require that we review periodically the carrying value of our oil and natural gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and natural gas properties. In the future because our properties serve as collateral for credit facilities, a write down in the carrying values of our properties could require us to repay debt earlier than would otherwise be required. A write-down would also constitute a non-cash charge to earnings. It is likely that the effect of such a write-down could also negatively impact the trading price of our securities.

We account for our oil and natural gas properties using the successful efforts method of accounting. Under this method, all development costs and acquisition costs of proved properties are capitalized and amortized on a units-of-production basis over the remaining life of proved developed reserves and proved reserves, respectively. Costs of drilling exploratory wells are initially capitalized, but charged to expenses if and when a well is determined to be unsuccessful. We evaluate impairment of our proved oil and natural gas properties whenever events or changes in circumstances indicate an asset’s carrying amount may not be recoverable. The risk that we will be required to write down the carrying value of our oil and natural gas properties increases when oil and natural gas prices are low or volatile. In addition, write-downs would occur if we were to experience sufficient downward adjustments to our estimated proved reserves or the present value of estimated future net revenues.

Potential legislative and regulatory actions addressing climate change could increase our costs, reduce our revenue and cash flow from oil and gas sales or otherwise alter the way we conduct our business.

Future changes in the laws and regulations to which we are subject may make it more difficult or expensive to conduct our operations and may have other adverse effects on us. For example, the USEPA has issued a notice of finding and determination that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, which allows the USEPA to begin regulating emissions of GHGs under existing provisions of the CAA. The USEPA has begun to implement GHG-related reporting and permitting rules. Similarly, the U.S. Congress has considered and may in the future consider “cap and trade” legislation that would establish an economy-wide cap on emissions of GHGs in the United States and would require most sources of GHG emissions to obtain GHG emission “allowances” corresponding to their annual emissions of GHGs. Any laws or regulations that may be adopted to restrict or reduce emissions of GHGs would likely require us to incur increased operating costs and could have an adverse effect on demand for our production.

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

Congress has considered legislation to amend the SDWA to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process and other legislation regulating hydraulic fracturing has been considered, and in some cases adopted, at various levels of government. Hydraulic fracturing is an important and commonly used process in the completion of unconventional gas wells in shale formations as well as tight conventional formations. This process involves the injection of water, sand and chemicals under pressure into rock formations to stimulate gas production. Sponsors of these bills have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies and/or that hydraulic fracturing could pose a variety of other risks. Any additional level of regulation could lead to operational delays, or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing, and increase our costs of compliance and doing business.

Gas drilling and production operations require adequate sources of water to facilitate the fracturing process and the disposal of that water when it flows back to the wellbore. If we are unable to obtain adequate water supplies and dispose of the water we use or remove at a reasonable cost and within applicable environmental rules, our ability to produce gas commercially and in commercial quantities would be impaired.

New environmental regulations governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase operating costs and cause delays, interruptions or termination of operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial performance. Water that is used to fracture gas wells must be removed when it flows back to the wellbore. Our ability to remove and dispose of water will affect our production and the cost of water treatment and disposal may affect our profitability. The imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct hydraulic fracturing or disposal of waste, including produced water, drilling fluids and other wastes associated with the exploration, development and production of gas.

Proposed changes to U.S. tax laws, if adopted, could have an adverse effect on our business, financial condition, results of operations and cash flows.

From time to time legislative proposals are made that would, if enacted, make significant changes to U.S. tax laws. These proposed changes have included, among others, eliminating the immediate deduction for intangible drilling and development costs, eliminating the deduction from income for domestic production activities relating to oil and natural gas exploration and development, repealing the percentage depletion allowance for oil and natural gas properties and extending the amortization period for certain geological and geophysical expenditures. Such proposed changes in the U.S. tax laws, if adopted, or other similar changes that reduce or eliminate deductions currently available with respect to oil and natural gas exploration and development, could adversely affect our business, financial condition, results of operations and cash flows.

The adoption and implementation of new statutory and regulatory requirements for derivative transactions could have an adverse impact on our ability to hedge risks associated with our business and increase the working capital requirements to conduct these activities.

On July 21, 2010, the President signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Reform Act, which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The legislation required the Commodities Futures Trading Commission, or the CFTC, and the SEC to promulgate rules and regulations implementing the new legislation, which they have done since late 2010. The CFTC has introduced dozens of proposed rules coming out of the Dodd-Frank Reform Act, and has promulgated numerous final rules based on those proposals. The effect of the proposed rules and any additional regulations on our business is not yet entirely clear, but it is increasingly clear that the costs of derivatives-based hedging for commodities will likely increase for all market participants. Of particular concern, the Dodd-Frank Reform Act does not explicitly exempt end users from the requirements to post margin in connection with hedging activities. While several senators have indicated that it was not the intent of the Act to require margin from end users, the exemption is not in the Act. While rules proposed by the CFTC and federal banking regulators appear to allow for non-cash collateral and certain exemptions from margin for end users, the rules are not final and uncertainty remains. The full range of new Dodd-Frank requirements to be enacted, to the extent applicable to us or our derivatives counterparties, may result in increased costs and cash collateral requirements for the types of derivative instruments we use to mitigate and otherwise manage our financial and commercial risks related to fluctuations in oil and natural gas prices. In addition, final rules were promulgated by the CFTC imposing federally-mandated position limits covering a wide range of derivatives positions, including non-exchange traded bilateral swaps related to commodities including oil and natural gas. These position limit rules were vacated by a Federal court in September 2012, and the CFTC has appealed that decision and could re-promulgate the rules in a manner that addresses the defects identified by the court. If these position limits rules go into effect in the future, they are likely to increase regulatory monitoring and compliance costs for all market participants, even where a given trading entity is not in danger of breaching position limits. These and other regulatory developments stemming from the Dodd-Frank Reform Act, including stringent new reporting requirements for derivatives positions and detailed criteria that must be satisfied to continue to enter into uncleared swap transactions, could have a material impact on our derivatives trading and hedging activities in the form of increased transaction costs and compliance responsibilities. Any of the foregoing consequences could have a material adverse effect on our financial position, results of operations and cash flows.

The borrowing base under our bank credit facility may be reduced below the amount of borrowings outstanding under such facility.

Under the terms of our bank credit facility, our borrowing base is subject to redeterminations at least semi-annually based in part on prevailing oil and gas prices. A negative adjustment could occur if the estimates of future prices used by the bank in calculating the borrowing base are significantly lower than those used in the last redetermination. The next redetermination of our borrowing base is scheduled to occur soon after by March 31, 2016. The lender has not yet completed the current redetermination. In addition, the portion of our borrowing base made available to us is subject to the terms and covenants of the bank credit facility including, without limitation, compliance with the ratios and other financial covenants of such facility. In the event the amount outstanding under our bank credit facility exceeds the redetermined borrowing base, we could be forced to repay a portion of our borrowings.

We may not have sufficient funds to make any required repayment. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell a portion of our assets.

Restrictive debt covenants could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.

Our bank credit facility contains a number of significant covenants that, among other things, restrict or limit our ability to:

- pay dividends or distributions on our capital stock or issue stock;
- repurchase, redeem or retire our capital stock;
- make certain loans and investments;
- sell assets;
- enter into certain transactions with affiliates;
- create or assume certain liens on our assets;
- enter into sale and leaseback transactions; or
- merge or to enter into other business combination transactions.

Also, our bank credit facility requires us to maintain compliance with specified financial ratios and satisfy certain financial condition tests. Our ability to comply with these ratios and financial condition tests may be affected by events beyond our control, and we cannot assure you that we will meet these ratios and financial condition tests. These financial ratio restrictions and financial condition tests could limit our ability to obtain future financings, make needed capital expenditures, withstand a future downturn in our business or the economy in general or otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under our bank credit facility impose on us.

A breach of any of these covenants or our inability to comply with the required financial ratios or financial condition tests could result in a default under our bank credit facility. A default, if not cured or waived, could result in all indebtedness outstanding under our bank credit facility to become immediately due and payable. If that should occur, we may not be able to pay all such debt or borrow sufficient funds to refinance it. Even if new financing were then available, it may not be on terms that are acceptable to us. If we were unable to repay those amounts, the lenders could accelerate the maturity of the debt or proceed against any collateral granted to them to secure such defaulted debt.

We have defaulted under our Credit Agreement with Texas Capital Bank, which we refer to as our Lender. Although our Lender has continued to forbear all existing events of default, as long as we do not cure our defaults or otherwise satisfy our obligations under the Credit Agreement, the Lender could foreclose resulting in a material adverse effect on our financial condition and ability to operate and our stock could lose significant or all of its value.

On February 20, 2014, Aurora, as borrower, entered into the Credit Agreement with the Lender. Victory and Navitus guaranteed Aurora's obligations under the Credit Agreement. The initial borrowing base under the Credit Agreement on February 20, 2014 was set at $1,450,000. The borrowing base is determined by the Lender, in its sole discretion, based on customary lending practices, review of the oil and natural gas properties included in the borrowing base, financial review of Aurora, Victory and Navitus and such other factors as may be deemed relevant by the Lender. The borrowing base is re-determined (i) on or about June 30 of each year based on the previous December 31 reserve report prepared by an independent reserve engineer, and (ii) on or about August 31 of each year based on the previous June 30 reserve report prepared by Aurora’s internal reserve engineers or an independent reserve engineer and certified by an officer of Aurora. The Credit Agreement will mature on February 20, 2017. Loans made under the Credit Agreement are secured by (i) a first priority lien in the oil and gas properties of Aurora, Victory and Navitus, and (ii) a first priority security interest in substantially all of the assets of Aurora and its subsidiaries, if any, as well as in 100% of the partnership interests in Aurora held by Victory and Navitus.

The Credit Agreement contains various affirmative and negative covenants. These covenants, among other things, limit additional indebtedness, additional liens and transactions with affiliates. Among the covenants contained in the Credit Agreement are financial covenants that Aurora will maintain a minimum EBITDAX to Cash Interest Ratio of 3.5 to 1.0 and a minimum Current Ratio of not less than 1.0 to 1.0. The Current Ratio is defined under the covenants to include, as a current asset, the revolving credit availability. At December 31, 2015, Aurora's Current Ratio was 0.10 to 1 and it was therefore not in compliance with the aforementioned Current Ratio covenant requiring a ratio of current assets to current liabilities of not less than 1 to 1.

On April 13, 2015, we received the annual Borrowing Base Adjustment called for under the terms of the Credit Agreement, which called for a decrease in the borrowing base of $300,000 payable by May 13, 2015, and an increase in the monthly reduction amount to $10,000 commencing as of June 1, 2015. Additionally, the Lender notified Aurora that, based on the Lender’s redetermination of Aurora’s borrowing base, the monthly reduction amount under the Credit Agreement was increased, commencing on June 1, 2015, from $0 to $10,000. Pursuant to this increase in the monthly reduction amount, Aurora’s borrowing base will be automatically reduced by $10,000 on the first day of each calendar month beginning on June 2015 until the Lender’s next periodic borrowing base redetermination.

As of June 30, 2015, Aurora was out of compliance with the Current Ratio, and out of compliance with the EBITDAX to Cash Interest Ratio due to its reduced revenue streams from price and production declines and continued high general and administrative expenses for the quarter ended June 30, 2015. We made one payment in the amount of $10,000 in June 2015.

On August 21, 2015, we executed a Forbearance Agreement whereby the Lender would forbear all existing events of default which includes all payments under the previously mentioned Borrowing Base Deficiency payments not yet paid under the April 13, 2015 Redetermination Date notification, as well as the late interest payments for June, July and August 2015, violations of Aurora financial covenants for the three months ended March 31, 2015, and June 30, 2015, and default notice for the late filing of March 31, 2015 financial reports. On August 26, 2015, we paid the Lender $76,081, including $60,000 in the outstanding principle balance andto cover a portion of the deficiency payment, as well as a Forbearance document fee and Lender's legal expenses, as required by the Forbearance Agreement, and the aforementioned Forbearance Agreement went into effect for the $260,000 remaining borrowing base deficiency payment. On August 31, 2015, the Forbearance Agreement terminated pursuant to its terms. We did not make the above payment and have been in continuous contact with its lender regarding our plan of payment of the $260,000 as well as the remaining credit facility balance. We made an additional $50,000 principle payment to the Lender on October 14, 2015 as part of that plan. Total payments to the Lender for principle reduction therefore totaled $120,000 in 2015.

As a result of the foregoing, we are in default of the Credit Agreement and related agreements. The Lender could accelerate our obligations under the Credit Agreement at any time. If the Lender accelerates our obligations under the Credit Agreement, we will not have sufficient funds to pay down all of the obligations and may be forced to liquidate, wind down our operations or resort to bankruptcy protection. If so, our common stock could become worthless.

We are exposed to the credit risk of our customers and other counterparties, and a general increase in the nonperformance by counterparties could have an adverse impact on our cash flows, results of operations and financial condition.

We are subject to risks of loss resulting from nonperformance by our counterparties. Any deterioration in the financial health of our counterparties or any factors causing reduced access to capital for them may result in the reduction in their ability to pay or otherwise perform on their obligations to us. Any increase in the nonperformance any of our counterparties, either as a result of recent changes in financial and economic conditions or otherwise, could have an adverse impact on our operating results and could adversely affect our liquidity.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our success largely depends on the success of our exploitation, exploration, development and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control;

including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyzes, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Our costs of drilling, completing and operating wells are often uncertain before drilling commences. Overruns in budgeted expenditures are a common risk that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel drilling operations, including the following:

- delays imposed by or resulting from compliance with regulatory requirements;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;

- equipment failures or accidents;
- adverse weather conditions;
- reductions in oil and gas prices; and
- oil and gas property title problems.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of our reported reserves. In order to prepare our estimates, we must project production rates and the timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires that economic assumptions be made about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Therefore, estimates of oil and natural gas reserves are inherently imprecise.

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

Our results of operations could be adversely affected as a result of impairments of oil and natural gas properties.

While we provide that our assets will be depleted over the estimated productive reserves of the oil and natural gas wells, these assets must also be tested at least annually for impairment. Management makes certain estimates and assumptions when determining the fair value of net assets and liabilities, including, among other things, an assessment of market conditions, projected cash flows, investment rates, cost of capital and growth rates, which could significantly impact the reported value of drilling costs and other intangible assets. Fair value is determined using a combination of the discounted cash flow, market multiple and market capitalization valuation approaches. Absent any impairment indicators, we perform our impairment tests annually during the fourth quarter. Any future impairment, including impairments of the carrying values of drilling costs and other intangible assets, could negatively impact our results of operations for the period in which the impairment is recognized.

If we are not successful in continuing to grow our business, then we may have to scale back or even cease our ongoing business operations.

Our success is significantly dependent on a successful acquisition, drilling, completion and production program. We may be unable to locate recoverable reserves or operate on a profitable basis. If our business plan is not successful, and we are not able to operate profitably, investors may lose some or all of their investment in us.

We depend on successful exploration, development and acquisitions to maintain revenue in the future.

In general, the volume of production from oil and natural gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Except to the extent that successful exploration and development activities are conducted on properties we own or we acquire properties containing proved reserves, or both, our proved reserves will decline as reserves are produced. Our future oil and natural gas production is, therefore, highly dependent on our level of success in finding or acquiring additional reserves. Additionally, the business of exploring for, developing, or acquiring reserves is capital intensive. Recovery of our reserves, particularly undeveloped reserves, will require significant additional capital expenditures and successful drilling operations. To the extent cash flow from operations is reduced and external sources of capital become limited or unavailable, our ability to make the necessary capital investment to maintain or expand our asset base of oil and natural gas reserves would be impaired. In addition, we may be required to find partners for any future exploratory activity. To the extent that others in the industry do not have the financial resources or choose not to participate in our exploration activities, we will be adversely affected.

We are not the operator of our oil and gas properties and therefore are not in a position to control the timing of development efforts, the associated costs or the rate of production of the reserves on such properties.

We are a non-operator with respect to our natural gas and oil properties. Consequently, we have limited ability to exercise influence over, and control the risks associated with, the operation of these properties. The success and timing of leasehold acquisition, drilling and development activities therefore will depend upon a number of factors outside of our control, including:

- the timing and amount of capital expenditures;
- the availability of suitable drilling equipment, production and transportation infrastructure and qualified operating personnel;
- the operator’s expertise and financial resources;
- approval of other participants in drilling wells;
- selection of technology; and
- the rate of production of the reserves.

In addition, when we are not the majority owner or operator of a particular oil or natural gas project, if we are not willing or able to fund our capital expenditures relating to such projects when required by the majority owner or operator, our interests in these projects may be reduced or forfeited.

As a result of any of the above or other failure of the operator to act in ways that are in our best interest, our results of operations could be adversely affected.

Our future acquisitions may yield revenues and/or production that vary significantly from our projections.

In acquiring producing properties, we assess the recoverable reserves, future oil and natural gas prices, operating costs, potential liabilities and other factors relating to such properties. Our assessments are necessarily inexact and their accuracy is inherently uncertain. Our review of a subject property in connection with our acquisition assessment will not reveal all existing or potential problems or permit us to become sufficiently familiar with the property to assess fully its deficiencies and capabilities.

We may not inspect every well, and we may not be able to identify structural and environmental problems even when we do inspect a well. If problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of those problems. Any acquisition of property interests may not be economically successful, and unsuccessful acquisitions may have a material adverse effect on our financial condition and future results of operations.

We cannot assure you that:

- we will be able to identify desirable oil and gas prospects and acquire leasehold or other ownership interests in such prospects at a desirable price;
- any completed, currently planned, or future acquisitions of ownership interests in oil and gas prospects will include prospects that contain proved oil and gas reserves;
- we will have the ability to develop prospects which contain proven natural gas or oil reserves;
- we will have the financial ability to consummate additional acquisitions of ownership interests in oil and gas prospects or to develop the prospects which we acquire to the point of production; or
- we will be able to consummate such additional acquisitions on terms favorable to us.

We face strong competition from other oil and gas companies.

We encounter competition from other oil and gas companies in all areas of our operations, including the acquisition of exploratory prospects and proved properties. Our competitors include major integrated oil and gas companies and numerous independent oil and gas companies, individuals, and drilling and income programs. Many of our competitors are large, well-established companies that have been engaged in the oil and gas business much longer than we have and possess substantially larger operating staffs and greater capital resources than we do. These companies may be able to pay more for productive oil and gas properties and may be able to define, evaluate, bid for, and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may be able to expend greater resources on the existing and changing technologies that we believe are and will be increasingly important to attaining success in the industry. We may not be able to conduct our operations, evaluate, and select suitable properties and consummate transactions successfully in this highly competitive environment.

The unavailability or high cost of drilling rigs, equipment, supplies or personnel could affect adversely our ability to execute on a timely basis our exploration and development plans within budget, which could have a material adverse effect on our financial condition and results of operations.

Shortages or the high cost of drilling rigs, equipment, supplies or personnel could delay or affect adversely our exploration and development operations, which could have a material adverse effect on our financial condition and results of operations. Demand for drilling rigs, equipment, supplies, and personnel are currently very high in the areas in which we operate. An increase in drilling activity in the areas in which we own properties could further increase the cost and decrease the availability of necessary drilling rigs, equipment, supplies and personnel.

We depend on key management personnel and technical experts. The loss of key employees or access to third party technical expertise could impact our ability to execute our business.

If we lose the services of the senior management, or access to independent land men, geologists and reservoir engineers with whom we have strategic relationships, our ability to function and grow could suffer, in turn, negatively affecting our business, financial condition and results of operations.

The marketability of our natural gas production depends on facilities that we typically do not own or control, which could result in a curtailment of production and revenues.

The marketability of our gas production depends in part upon the availability, proximity and capacity of gas gathering systems, pipelines and processing facilities. We generally deliver gas through gas gathering systems and gas pipelines that we may not own under interruptible or short-term transportation agreements. Under the interruptible transportation agreements, the transportation of our gas may be interrupted due to capacity constraints on the applicable system, due to maintenance or repair of the system, or for other reasons as dictated by the particular agreements. Our ability to produce and market natural gas on a commercial basis could be harmed by any significant change in the cost or availability of such markets, systems or pipelines.

We are subject to complex laws that can affect the cost, manner or feasibility of doing business.

The exploration, development, production and sale of oil and natural gas are subject to extensive federal, state, local and international regulation. We may be required to make large expenditures to comply with such governmental regulations. Matters subject to regulation include:

- natural disasters;
- permits for drilling operations;
- drilling and plugging bonds;
- reports concerning operations;
- the spacing and density of wells;
- unitization and pooling of properties;
- environmental maintenance and cleanup of drill sites and surface facilities; and
- protection of human health.

From time to time, regulatory agencies have also imposed price controls and limitations on production by restricting the rate of flow of oil and gas wells below actual production capacity in order to conserve supplies of oil and gas.

Under these laws, we could be liable for personal injuries, property damage and other damages. Failure to comply with these laws also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws could change in ways that substantially increase our costs. Any such liabilities, penalties, suspensions, terminations or regulatory changes could materially adversely affect our financial condition and results of operations.

The financial condition of our operators could negatively impact our ability to collect revenues from operations.

We currently do not and in the future we may not operate all of the properties in the future in which we have working interests. In the event that an operator of our properties experiences financial difficulties, this may negatively impact our ability to receive payments for our share of net production that we are entitled to under our contractual arrangements with such operator. While we seek to minimize such risk by structuring our contractual arrangements to provide for production payments to be made directly to us by first purchasers of the hydrocarbons, there can be no assurances that we can do so in all situations covering our non-operated properties.

Risks Related to Our Common Stock

We continue to incur operating losses and additional losses in the future which may adversely affect our business, financial condition and cash flows.

While we have taken steps to add further oil and natural gas reserves through additional investment, there is no guarantee we will become profitable, or have continued and sustained profitability over the longer term. Our profitability is affected by, among other factors, our ability to have continued access to high-potential reserves, our success in drilling operations, the economic life of any reserves developed, and the market price of crude oil or natural gas. Future losses may adversely affect our business, financial condition and cash flows.

A decline in the price of our common stock could affect our ability to raise further working capital and adversely impact our operations.

A prolonged decline in the price of our common stock could result in a reduction in the liquidity of our common stock and a reduction in our ability to raise capital. Because our operations may be financed through the sale of equity securities, a decline in the price of our common stock could be especially detrimental to our liquidity and our continued operations. Any reduction in our ability to raise equity capital in the future would force us to reallocate funds from other planned uses and would have a significant negative effect on our business plans and operations, including our ability to develop new projects and continue our current operations. If our stock price declines, we may not be able to raise additional capital or generate funds from operations sufficient to meet our obligations.

Trading of our stock may be restricted by the SEC's "Penny Stock" regulations which may limit a stockholder's ability to buy and sell our stock.

The SEC defines and applies “penny stock” regulations to any equity security that has a market price of less $5.00 per share or an exercise price of less than $5.00 per share, subject to certain exceptions. Our securities are covered by the penny stock rules, which impose additional sales practice requirements on broker-dealers who sell to persons other than established customers or "accredited investors." The term "accredited investor" refers generally to institutions with assets in excess of $5,000,000 or individuals with a net worth in excess of $1,000,000 (excluding the value of their primary residence and mortgage debt on their primary residence) or annual income exceeding $200,000 or $300,000 jointly with his or her spouse. The penny stock rules require a broker-dealer, prior to a transaction in a penny stock not otherwise exempt from the rules, to deliver a standardized risk disclosure document in a form prepared by the SEC that provides information about penny stocks and the nature and level of risks in the penny stock market. The broker-dealer also must provide the customer with current bid and offer quotations for the penny stock, the compensation of the broker-dealer and its salesperson in the transaction and monthly account statements showing the market value of each penny stock held in the customer's account. The bid and offer quotations, and the broker-dealer and salesperson compensation information, must be given to the customer orally or in writing prior to effecting the transaction and must be given to the customer in writing before or with the customer's confirmation. In addition, the penny stock rules require that prior to a transaction in a penny stock not otherwise exempt from these rules; the broker-dealer must make a special written determination that the penny stock is a suitable investment for the purchaser and receive the purchaser's written agreement to the transaction. These disclosure requirements may have the effect of reducing the level of trading activity in the secondary market for the stock that is subject to these penny stock rules. Consequently, these penny stock rules may affect the ability of broker-dealers to trade our securities. We believe that the penny stock rules discourage investor interest in and limit the marketability of, our common stock.

FINRA sales practice requirements may also limit a stockholder’s ability to buy and sell our stock.

In addition to the “penny stock” rules described above, the Financial Industry Regulatory Authority (“FINRA”) has adopted rules that require that in recommending an investment to a customer, a broker-dealer must have reasonable grounds for believing that the investment is suitable for that customer. Prior to recommending speculative low priced securities to their non-institutional customers, broker-dealers must make reasonable efforts to obtain information about the customer’s financial status, tax status, investment objectives and other information. Under interpretations of these rules, FINRA believes that there is a high probability that speculative low priced securities will not be suitable for at least some customers. The FINRA requirements make it more difficult for broker-dealers to recommend that their customers buy our common stock, which may limit your ability to buy and sell our stock and have an adverse effect on the market for our shares.

Trading in our common shares has been volatile and with low trading volumes, making it more difficult for our stockholders to sell their shares or liquidate their investments with predictability.

Our common shares are currently quoted on the OTC Markets. The trading price of our common shares has been subject to wide fluctuations and low trading volumes. Trading prices of our common shares may fluctuate in response to a number of factors, many of which will be beyond our control. The stock market has generally experienced extreme price and volume fluctuations that have often been unrelated or disproportionate to the operating performance of companies with no current business operation. There can be no assurance that trading prices and price earnings ratios previously experienced by our common shares will be matched or maintained. These broad market and industry factors may adversely affect the market price of our common shares, regardless of our operating performance. In the past, following periods of volatility in the market price of a company's securities, securities class-action litigation has often been instituted. Such litigation, if instituted, could result in substantial costs for us and a diversion of management's attention and resources.

Our securities are considered highly speculative.

Our securities are considered highly speculative, generally because of the nature of our business and the early stage we are in of building a long life asset base. While operating revenues are planned to increase over time, through our capital and exploration program, there are risks associated with drilling success, oil and natural gas prices, and our ability to raise additional monies through share offerings or debt. Access to capital is vital and unless the revenue base grows over time that could prove difficult to accomplish.

We may issue additional shares of capital stock that could affect the value of existing holders of our stock, stock options, or warrants.

Our board of directors is authorized to issue additional classes or series of shares of our capital stock without any action on the part of our stockholders. Our board of directors also has the power, without stockholder approval, to set the terms of any such classes or series of shares of our capital stock that may be issued, including voting rights, dividend rights, conversion features, preferences over shares of our existing class of common stock with respect to dividends or if we liquidate, dissolve or wind up our business and other terms. If we issue shares of our capital stock in the future that have preference over shares of our existing class of common stock with respect to the payment of dividends or upon our liquidation, dissolution or winding up, or if we issue shares of capital stock with voting rights that dilute the voting power of shares of our existing class of common stock, the rights of holders of shares of our common stock or the trading price of shares of our common stock and, as a result, the market value of the options and warrants into shares of common stock could be adversely affected.

Pending litigation may place a financial burden on our resources and the outcome of the litigation may not be favorable to us.

We are or may become party to legal proceedings that are considered to be either ordinary or routine litigation incidental to our business or not material to our financial position or results of operations. We also are or may become party to legal proceedings with the potential to be material to our financial position or results of operations.

Item 1B. Unresolved Staff Comments

We are a “smaller reporting company” as defined by Rule 12b-2 under the Securities Exchange Act, and as such, are not required to provide the information required under this item.

Item 2. Properties

Office Space Leases.

Our executive office space lease is month to month and is for approximately 1,200 square feet at 3355 Bee Caves Road, Suite 608, Austin, Texas 78746. The monthly lease cost is $2,500.

Portfolio.

As of December 31, 2015, we had 37 gross and 9 net wells, in production. Our portfolio of producing assets now includes the Eagle Ford property, the Fairway property, the Bootleg Canyon Ellenberger Field, the Adams-Baggett Gas Field, the Chapman Ranch, the Morgan Property, and the Clear Water Wolfberry Resource Play. All of the Company's assets are located in the United States.

Proved commercial accumulations of hydrocarbons now occur in multiple target zones at depths ranging from 4,700 to 13,100 feet, with the majority of proved reserves being located on properties in the Eagleford and Permian Basin of Texas and New Mexico. As we continue to drill available locations on its current properties and add properties that are accessible to us through our established deal flow pipeline, we anticipate an accelerated pace toward oil-weighted production and the addition of new reserves.

The Eagle Ford Property, Lavaca and Gonzales County, Texas

In February 2015, as a result of the dissolution of the proposed business combination with Lucas, Victory received wellbore assignments for non-operated working interest in five (5) gross wells, which we refer to as the Penn Virginia Wells, located in the Eagle Ford Field in Gonzales and Lavaca County, Texas. During the quarter ended March 31, 2015, Victory participated in the successful development of these five wells, as operated by Penn Virginia Oil & Gas LP. The properties include the Dingo #1, #2 and #3, in which we received a 3.276% working interest and a 2.457% net revenue interest, and the Platypus Hunter #2 and #3, in which we retain a 1.481% working interest and a 1.114% net revenue interest, respectively. As of December 31, 2015, the Penn Virginia wells were producing approximately 23 net BOEPD, comprised of 53% oil.

As of December 31, 2015, the Eagle Ford Property has 29.9 MBOE of recoverable reserves, or 47% of the Company's total proved producing reserves.

The Lightnin' Property, Glascock County, Texas

On June 5, 2014, Victory, through its controlling interest and as managing partner in Aurora, sold certain leasehold properties and all of Aurora’s related interests in approximately 640 gross and 128 net mineral acres located in Glascock County, Texas, which we refer to as the Lightnin Assets, to an unrelated third party, which we refer to as the Lightnin Buyer, for approximately $4 million in cash gross to Aurora. The sale was made pursuant to a Purchase and Sale Agreement dated as of April 30, 2014 by and among the working interest owner/sellers, including Aurora, and the Lightnin' Buyer. The effective date for the transaction was April 1, 2014. Aurora held a 20% working and 15% net revenue interest in the Lightnin' Assets which were operated by a third party. Estimated daily net production to Aurora's interest was approximately 36 BOEPD (barrels of oil equivalent per day) at the time of the sale from the 3 producing wells. We recognized a gain on the sale of the Lightnin' Assets of $2,160,099 in our consolidated statement of operations as of December 31, 2014.

The Bootleg Canyon Property, Pecos County, Texas

Acquired in 2011, this 4,000+ acre lease is located in Pecos County, Texas. There are now two producing Ellenberger oil wells and one producing Connell gas well on this 3D seismic-controlled property.

During the year ended December 31, 2015, gross production for the two oil wells (University 6 #1 and #2) was just over 48 MBO.

The gas well (University 7 #1) spud on December 23, 2012 and went into completion on March 6, 2013. During the year ended December 31, 2015, gross production was 2,431 Mcf, or 7 Mcf per day.

The operator of the Bootleg Canyon Property wells currently believes the University 6 #1 and 6 #2 are subject to water drive, and as a result, has restricted the flow of hydrocarbons to avoid excess water production. In addition, unstable line pressure in the University 7 #1 well has caused a significant decrease in year over year production.

The acreage held currently provides 160-acre spacing between wells and thus an opportunity to drill additional wells on the prospect acreage. It is estimated there may be ten total well locations on the property. Our company, through its interest in Aurora, holds a 5 % working interest and a 3.75 % net revenue interest.

The Bootleg Canyon Property is estimated to hold 7.7 MBOE of reserves, or 12% of the Company's total proved producing reserves.

Development capital required for the remaining ten well locations is estimated to be $870,650.

The Adams-Baggett Property, Crockett County, Texas

Our company, via its partnership interest in Aurora, received its first production revenue from this field in March of 2008 and continues to receive income today. Canyon sandstones are the primary hydrocarbon target within this prospect and they form a prolific low-permeability gas play located in the Val Verde Basin of Southwest Texas. Natural gas from the Canyon Sandstone generally receives a premium in price above the standard market price for natural gas due to its higher BTU content per cubic foot. In addition, each of the Adams-Baggett wells have historically displayed an established, well behaved decline trend of 4.5% per year.

The Canyon Sandstone gas play is part of the large Adams-Baggett Canyon Sandstone gas field. The Canyon Sandstone formation is found at a depth of 4,300 feet to 4,900 feet. The average life span of a Canyon Sandstone gas well is approximately 30 years.

Aurora Energy Partners holds a working interest and an overriding royalty interest in nine wells; 100% WI, 74% NRI, and a 1.563% ORRI in seven wells, and a 50% WI with 38% NRI in two wells in the Adams-Baggett property.

Reserve estimates completed for the year ended December 31, 2015 indicate the Adams-Baggett Property holds 23.1 MBOE of reserves, or 36% of the Company's total proved producing reserves.

Fairway, Howard County, Texas
On June 30, 2014, Aurora completed the initial closing, which we refer to as the First Closing, of a purchase of a 10% working and 7.5% net revenue interest in the proved and unproved Permian Basin Fairway Operations from Target Energy Limited, which we refer to as TELA, for an initial payment of $2,491,888 in cash, subject to customary purchase price adjustments. We refer to this acquisition as the Fairway Acquisition, which was undertaken pursuant to the terms and conditions of the Purchase and Sale Agreement dated June 30, 2014 between Aurora and TELA, which we refer to as the Fairway PSA. On the First Closing, TELA assigned certain assets in its Permian Basin Fairway Operation, which we refer to as the First Closing Assets, to Aurora. The second closing of the Fairway Acquisition, which we refer to as the Second Closing, was planned to follow the completion of curative title work and was expected in August 2014. At the Second Closing, TELA was to assign the remainder of its assets in its Permian Basin Fairway Operations to Aurora. The Effective Date for the transfer of all assets was May 1, 2014. The acquisition of the First Closing Assets included 7 producing wells and 4 wells completed and awaiting production start-up.
The acquisition of the First Closing Assets included seven producing wells and four wells completed and awaiting production start-up. On September 23, 2014, we mutually agreed to the termination of the Fairway PSA. Pursuant to the termination of the Fairway PSA, the Second Closing did not occur as the result of certain title impairment issues that were uncovered during the due diligence process and that were not remedied to the satisfaction of our company and TELA. No penalties or payments were due as a result of the termination of the Fairway PSA.
As of December 31, 2015, the Fairway Property has 2.5 MBOE of recoverable reserves, or 4% of the Company's total proved producing reserves.

Clearwater Wolfberry Resource Play, Howard County, Texas

In April 2011, our company, through its ownership in Aurora acquired a 1.5% working interest and a 1.125% net revenue interest in 3,186 gross acres known as the Clearwater Property. At the time of the acquisition this property contained two producing wells and a third exploration well was in progress. At year-end 2011, there were three producing oil wells on this property. During February 1, 2012 we assigned approximately 944 gross acres of mineral rights related to the Hamlin 26 and Hamlin 24 tracts to another operator in exchange for an overriding royalty interest proportional to the working interest held by us. In exchange for the assignment, we retained a 0.375% overriding royalty interest in the 944 gross acres. We still own a 1.5% working interest and a 1.125% net revenue interest in the remaining 2,242 acres.

The Clearwater Wolfberry Play is estimated to hold 0.7 MBOE of reserves, or 1% of the Company's total proved producing reserves.

The Chapman Ranch Property, Nueces County, Texas

Our company through its interest in Aurora acquired this prospect in April 2012. The prospect is located in south central Nueces County, Texas. The prospect wells are a conventional drilling play targeting the Frio Sands formation.

The first well was drilled and completed in July 2012. Multiple pay zones were present in the well-logs; however, oil and gas production from the target formation was not of a commercial quantity. A second well location is up-dip of the first well site and is in a different fault block.

This second well, the Chapman 4501, spud on December 22, 2013 and reached total depth of 7,800 feet on January 7, 2014. The well was perforated in several sections and was successfully flow tested from the Frio Sands on January 21, 2014 at 67 barrels of oil and 10 Mcf of dry gas per day.

On February 10, 2015, we received a recommendation from the operator to plug and abandon the Chapman 4501, citing high recompletion costs and poor reservoir behavior. We concurred with the operator's proposal and agreed to bear the prorata share of the plugging and surface reclamation expenses. In May of 2015, the operator commenced with the plug and abandonment activities.

Our company through its interest in Aurora holds a 5 % working interest and a 3.75 % net revenue interest.

Developed and Undeveloped Lease Acreage

The following table sets forth certain information regarding developed and undeveloped leasehold acreage held by Aurora as of December 31, 2015. “Developed Acreage” refers to acreage on which wells have been drilled or completed to a point that would permit production of oil and natural gas in commercial quantities. “Undeveloped Acreage” refers to acreage on which wells have not been drilled or completed to a point that would permit production of oil and natural gas in commercial quantities whether or not the acreage contains proved reserves. As detailed below, Victory Energy Corporation only holds wellbore interests in the Eagleford properties, and thus does not hold an acreage position.

			Developed Acreage		Undeveloped Acreage		Total Acreage	
	WI %		Gross	Net	Gross	Net	Gross	Net
Adams-Baggett Ranch	100.00	%	140.0	140.0	0.0	0.0	140.0	140.0
Adams-Baggett Ranch	50.00	%	20.0	10.0	0.0	0.0	20.0	10.0
The Fairway Prospect	10.00	%	240.0	24.0	560.0	56.0	800.0	80.0
Bootleg Prospect	5.00	%	480.0	24.0	4164.7	198.2	4644.7	222.2
Saddle Butte Prospect	3.00	%	0.0	0.0	2560.0	76.8	2560.0	76.8
The Uno-Mas Property	10.00	%	160.0	16.0	160.0	2.0	320.0	18.0
The Morgan Property	3.00	%	40.0	1.2	40.0	1.2	80.0	2.4
The Chapman Ranch Property	5.00	%	80.0	4.0	240.0	12.0	320.0	16.0
The Pinetop Property	4.00	%	80.0	3.2	1120.0	48.0	1200.0	51.2
The Eagleford Property (1)	3.28	%	0.0	0.0	0.0	0.0	0.0	0.0
The Eagleford Property (1)	1.48	%	0.0	0.0	0.0	0.0	0.0	0.0
Clearwater Wolfberry	1.50	%	160.0	2.4	2082.0	29.1	2242.0	31.5
Royalty Interest Acreage	—	%	0.0	0.0	944.0	3.5	944.0	3.5
Total Acreage			1,400	224.8	11,870.7	426.8	13,270.7	651.6

(1) Only wellbore working interests were conveyed to us in connection with our prior agreements with Lucas.

Internal Controls over Reserve Estimates, Technical Qualifications and Technologies Used

Our policies regarding internal controls over reserve estimates requires reserves to be in compliance with the SEC definitions and guidance, and for reserves to be prepared by an independent third party reserve engineering firm and reviewed by certain members of senior management, specifically our CEO.

Estimates of our reserves were outsourced to Cambrian Management and prepared by their independent reserve engineer, Mr. James Nicholson, who specializes in preparing reservoir studies, reserve estimates, and property evaluations. Mr. Nicholson, a Registered Professional Engineer, is a member of the Society of Petroleum Engineers, and a former chairman of the Permian Basin Oil & Gas Recovery Conference.

The objective of this study, provided on March 1, 2016, was to estimate reserves and value for properties owned by the Company as of December 31, 2015. The reserve study for the year ended December 31, 2015 represents 100% of the Company's year-end 2015 proved reserves, and 100% of the Company's pre-tax present value of proved reserves discounted at 10%.

Data furnished for this analysis included well drilling reports, logs, test data, operating costs and revenue statements. Production data were obtained from the Texas Railroad Commission records and was supplemented as needed by data from the Operators.

All estimated reserves contained in the report are expressed as gross and net reserves on all properties. Net reserves represent those reserves attributable to the Company. Values for reserves are expressed in terms of future net revenue and the present worth of future net revenue. Future net revenue is defined as the revenue accruing to the Company’s interests from production and the sale of the estimated net reserves after deducting production taxes and operating expenses.

No plugging costs or salvage values were considered in the evaluation, nor was any consideration given to Federal Income tax.

The properties evaluated for the analysis have proved developed producing (PDP) reserves and proved undeveloped reserves (PUD) as defined by the Society of Petroleum Engineers (SPE). The reserve guidelines as published by the SPE in March 2007 in the Petroleum Management System (SPE-PRMS) were used for this analysis. Production forecasts were made using methods appropriate for the individual property with the majority of forecasts being made with decline curve analysis.

Cash flow for the individual well cases were calculated until the monthly cash flow becomes negative; i.e., costs exceed revenue and the well is not economic. The individual cases were summed to produce the total value.

Using SEC guidelines in place for 2015, the gas and oil prices for the analysis were set at the average priced received on the “first-day-of-the-month” for the last 12 months, adjusted for appropriate differentials. The “benchmark” prices are $50.28 per barrel and $2.58 per MMBTU, as estimated by Ryder Scott. For each well, or case, the actual monthly prices received during the last 12 months were compared to NYMEX averages prices for the month. For each well a differential to the average was estimated. These differentials were applied to the “benchmark” prices and the resulting values were used for the future cash flow estimates. All prices were held constant per SEC guidelines.

Actual 2015 lease operating costs (LOE) for the properties were furnished for this review. The monthly costs were averaged for each well to determine a $/month per well operating cost. Non-recurring costs were omitted. Per SEC guidelines the operating costs are held constant for the life of the wells.

Drill and complete costs for the PUD well were based on estimates provided by the Operator.

The value estimated in this report is based on the assumption that the properties are not adversely affected by the existence of any hazardous substances, detrimental environmental conditions, or changes to regulations.

The study was completed using industry-accepted principles of engineering and evaluation that are predicated on established scientific concepts. However, the application of such principles involves extensive judgment and assumptions and is subject to changes in performance data, technical knowledge, economic conditions and statutory provisions. Consequently, reserve estimates and future value are furnished with the understanding that actual performance of the wells could vary from that as predicted.

Our independent consultants, including a geologist and an oil and gas operations professional have reviewed and approved the reserve report which is filed as an exhibit to this Annual Report on Form 10-K.

At December 31, 2015, our proved developed reserves accounted for 90% of total reserves. 58% of the total reserves are attributable to oil, while 42% are attributable to natural gas and other liquids. The following table sets forth our estimated proved oil and natural gas reserves for the 37 wells and the PV-10 of such reserves as of December 31, 2015 and 2014.

Total Estimated Proved Reserves	2015	2014
Proved Developed Reserves		
Oil (Mbbl)	34.40	13.64
Gas (Mmcf)	176.96	598.14
Total proved developed reserves (Mboe)	63.89	113.33
Proved Undeveloped Reserves		
Oil (Mbbl)	7.02	7.02
Gas (Mmcf)	1.79	1.79
Total proved undeveloped reserves (Mboe)	7.32	7.32
Total Proved Reserves (Mboe)	71.21	120.65
% Oil	58.17 %	17.12 %
% Proved Developed	89.72 %	93.93 %
PV- 10% (in thousands)	$872.13	$1,464.57

Reconciliation of PV-10 to Standardized Measure

PV-10 is derived from the Standardized Measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the Standardized Measure of discounted future net cash flows on a pre-tax basis. PV-10 is equal to the Standardized Measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10 %. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the Standardized Measure of discounted future net cash flows. Our PV-10 measure and the Standardized Measure of discounted future net cash flows do not purport to represent the fair value of our oil and natural gas reserves.

The following table provides a reconciliation of PV-10 to the Standardized Measure of discounted future net cash flows at December 31, 2015 and 2014 for our company:

	December 31,	
	2015	2014
	(In Thousands)	
PV-10	$872.1	$1,464.6
Present value of future income taxes discounted at 10%	287.4	500.6
Standardized Measure of discounted future net cash flows	$584.7	$964.0

Estimated Future Net Revenues

The following table sets forth the estimated future net revenues, excluding derivative contracts, from proved reserves, the present value of those net revenues (PV-10) and the standardized measure values at December 31, 2015 and 2014 for our company:

	December 31,	
	2015	2014
	(In Thousands)	
Undiscounted future net revenues	$2,345.9	$4,920.2
Present value of net revenues:		

Before income tax (PV-10)	872.1	1,464.6
After income tax (Standardized Measure)	$584.7	$964.0

Productive Wells

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Productive wells are producing wells or wells capable of production. This does not include water source wells, water injection wells or water disposal wells. Productive wells do not include any wells in the process of being drilled and completed that are not yet capable of production, but does include old productive wells that are currently shut-in, because they are still capable of production. The following table sets forth the number of productive oil and natural gas wells in which we owned an interest as of December 31, 2015 and 2014 for our company.

A gross total of eleven producing wells were added to our portfolio during the year ended December 31, 2015. The change in producing wells reflects the assignment received by us for Eagle Ford properties in the first quarter of 2015, as well as overriding royalty interests in six gross wells completed during 2015.

	December 31,			
	2015		2014	
	Gross	Net	Gross	Net
Natural Gas	11.0	7.8	11.0	8.1
Oil	26.0	1.3	15.0	0.9
Totals	37.0	9.1	26.0	9.0

Technologies Used in Establishing Proved Reserves in 2015 and 2014

Our proved reserves in 2015 and 2014 were based on estimates generated through the integration of available and appropriate data, utilizing well established technologies that have been demonstrated in the field to yield repeatable and consistent results.

Data used in these integrated assessments included information obtained directly from the subsurface via wellbores, such as well logs, reservoir core samples, fluid samples, static and dynamic pressure information, production test data, and surveillance and performance information. The data utilized also included subsurface information obtained through indirect measurements, including high-quality 2-D and 3-D seismic data, calibrated with available well control. Surface geological information was also utilized in the preparation of the data where applicable. The tools used to interpret the data included proprietary seismic processing software, proprietary reservoir modeling and simulation software, and commercially available data analysis packages.

Proved Undeveloped Reserves

At December 31, 2015 and 2014, our proved undeveloped reserves included 1 prospect (University 6 #3) and 2 prospects (the Cotter 6 #2 and the University 6 #3), respectively. As we are not the operator of these properties, we cannot predict the timing of the development of the properties. The total quantity of proved undeveloped reserves for the year ended December 31, 2015 and 2014 were 7.32 MBOE and 7.32 MBOE, respectively.

The Company did not realize any material changes to its proved undeveloped reserves, nor did the Company convert any proved undeveloped reserves to prove producing reserves through investments or development. No material amounts of proved undeveloped reserves have remained undeveloped for five years or more.

Oil and Natural Gas Production, Production Prices and Production Costs

The following table sets forth certain information regarding our production volume, and average sales and production costs for the periods indicated for our Company. The Company is subject to any delivery commitments or contracts as related to the production, marketing and sale of oil and gas.

	Years Ended December 31,		
	2015	2014	2013
Production:			
Oil (Bbls)	12,152	6,509	5,810
Natural gas (Mcf)	37,419	45,577	44,833
BOE	18,389	14,106	13,282
Average sales prices:			
Oil (per Bbl)	$45.72	$71.16	$84.81
Natural gas (per Mcf)	$2.51	$5.09	$5.35
BOE	$35.38	$49.29	$55.17
Average production costs			
Lease operating expense	$159,800	$190,207	$203,132
Production tax	$32,704	$34,867	$44,218
BOE	$10.47	$15.96	$18.61

Drilling and Other Exploratory and Development Activities

The following table sets forth our drilling activity for the periods indicated.

	Years Ended December 31,					
	2015		2014		2013	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive	—	—	—	—	4.0	0.5
Dry	—	—	—	—	1.0	0.1
Developmental Wells						
Productive	5.0	0.1	—	—	2.0	0.3
Dry	—	—	—	—	—	—

As of December 31, 2015, the Company was not involved in any oil and gas development activities, including the drilling and completion of wells, waterflood installation, pressure maintenance operations, or any other related activity of material importance.

Title to Properties

We believe that we have satisfactory title to substantially all of our active properties in accordance with standards generally accepted in the oil and natural gas industry. Our properties are subject to customary royalty interests, liens for current taxes and other burdens, which we believe do not materially interfere with the use of or affect the value of such properties. Prior to acquiring undeveloped properties, we perform a title investigation that is thorough but less vigorous than that conducted prior to drilling, which is consistent with standard practice in the oil and natural gas industry. Before we commence drilling operations, we conduct a thorough title examination and perform curative work with respect to significant defects before proceeding with operations. We have performed a thorough title examination with respect to substantially all of our active properties.

Item 3. LEGAL PROCEEDINGS

Cause No. 08-04-07047-CV; Oz Gas Corporation v. Remuda Operating Company, et al. v. Victory Energy Corporation.; In the 112th District Court of Crockett County, Texas.

Plaintiff Oz Gas Corporation (“Oz”) filed a lawsuit in April 2008 against various parties for bad faith trespass, among other claims, regarding the drilling of two wells on lands that Oz claims title to. On November 18, 2009, Victory Energy Corporation intervened in the lawsuit to protect its 50% interest in one of the named wells in the lawsuit (that being the 155-2 well located on the Adams Baggett Ranch in Crockett County, Texas).

This case was mediated, with no settlement reached. It went to trial February 8-9, 2012. The Court found in favor of Oz and rendered verdict against Victory and the other Defendants, jointly and severally. Victory appealed this case to the 8th Court of Appeals in El Paso, Texas where the Court of Appeals affirmed the verdict of the District Court and Victory filed a Motion for Rehearing, which was denied. Victory filed a Petition for Review in the Supreme Court of Texas on December 15, 2014 which was denied. Victory filed a Motion for Rehearing with the Supreme Court which was denied.Oz filed Interrogatories and Request for Production in Aid of Judgment which have been answered by Victory.

A Settlement and Forbearance Agreement was entered into on March 22, 2016, between the parties wherein no further post-judgment discovery or collection efforts will be made by Oz, for $140,000 net of a $14,000 payment received by the Oz receiver (see next following Cause No. C-1-CV-16-001610), with monthly payments of $7,500 commencing April, 15, 2016. This amount is included in Accrued Liabilities as of December 31, 2015.

Cause No. C-1-CV-16-001610; Oz Gas Corporation v. Victory Energy Corporation; In the County Court at Law No. 1 of Travis County, Texas.

Plaintiff Oz Gas Corporation (“Oz”) filed an Application for Turnover Relief in Travis County, Texas on February 19, 2016. This order was granted and Thomas L. Kolker was appointed as Receiver to assist in the collection of non-exempt assets. Victory itself has not been placed into Receivership. Victory filed its Motion to Vacate the Turnover that was heard and denied by the trial court. Oz has since filed an Amended Application for Turnover Relief and Appointment of a Receiver to be heard March 10, 2016. Victory filed its Notice of Appeal March 4, 2016. Victory and Oz are now in the process of attempting to resolve the case outside of the judicial process.

A Settlement and Forbearance Agreement was entered into on March 22, 2016, between the parties wherein no further post-judgment discovery or collection efforts will be made by Oz, for $140,000 net of a $14,000 payment received by the Oz receiver, with monthly payments of $7,500 commencing April 15, 2016, and an Agreed Motion Vacating Turnover Order with a Proposed Order Vacating Appointment of Receiver has been filed with the court.

Cause No. CV-47,230; James Capital Energy, LLC and Victory Energy Corporation v. Jim Dial, et al.; In the 142nd District Court of Midland County, Texas.

This is a lawsuit filed on or about January 19, 2010, by James Capital Energy, LLC and Victory Energy Corporation against numerous parties for fraud, fraudulent inducement, negligent misrepresentation, breach of contract, breach of fiduciary duty, trespass, conversion and a few other related causes of action. This lawsuit stems from an investment Victory entered into for the purchase of six wells on the Adams Baggett Ranch with the right of first refusal on option acreage.

On December 9, 2010, Victory was granted an interlocutory Default Judgment against Defendants Jim Dial, 1st Texas Natural Gas Company, Inc., Universal Energy Resources, Inc., Grifco International, Inc., and Precision Drilling & Exploration, Inc. The total judgment amounted to approximately $17,183,987.

Victory has added a few more parties to this lawsuit. Discovery is ongoing in this case and no trial date has been set at this time.

Victory believes they will be victorious against all the remaining Defendants in this case.

On October 20, 2011 Defendant Remuda filed a Motion to Consolidate and a Counterclaim against Victory. Remuda is seeking to consolidate this case with two other cases wherein Remuda is the named Defendant. An objection to this motion was filed and the cases have not been consolidated. Additionally, we do not believe that the counterclaim made by Remuda has any legal merit.

Cause No. 10-09-07213; Perry Howell, et al. v. Charles Gary Garlitz, et al.; In the 112th District Court of Crockett County, Texas.

The above referenced lawsuit was filed on or about September 6, 2010. This lawsuit alleges that Cambrian Management, Ltd. and Victory were trespassers on their land, and that they, along with other Defendants, drilled a well (115 #8) on land belonging to Plaintiffs. Plaintiffs claim trespass and unjust enrichment by certain Defendants because of the drilling of the 115 #8 well.

Discovery is ongoing in this case and no trial date has been set. Victory believes that the claims made by Plaintiffs have no merit and that they will prevail at trial. Mediation began on August 8, 2013 and was adjourned to a later date which has not been set yet.

Cause No. D-1-GN-13-000044; Aurora Energy Partners and Victory Energy Corporation v. Crooked Oaks, LLC; In the 261st District Court of Travis County, Texas.
Victory Energy Corporation sued Crooked Oaks, LLC a/k/a Crooked Oak, LLC for breach of a purchase and sale agreement dated May 7, 2012 in which Victory sold certain assets to Crooked Oaks, LLC for $400,000 of which only $200,000 has been paid as of December 31, 2014. The lawsuit seeks to recover the remaining balance owed of $200,000.00 from Crooked Oaks, LLC in addition to attorney's fees and all costs of court. Crooked Oaks, LLC has asserted a counterclaim for rescission of the underlying contract.
Victory and Crooked Oaks attended a mediation on February 10, 2016 where it was determined that Crooked Oaks was insolvent and since that date the case has been dismissed with prejudice.
Cause No. 50198; Trilogy Operating, Inc. v. Aurora Energy Partners; In the 118th Judicial District Court of Howard County, Texas.
This lawsuit was filed on January 9, 2015. This lawsuit alleges causes of action for declaratory judgment, breach of contract, and suit to quiet title regarding the drilling and completion of four wells. On or about February 12, 2015, the parties met at an informal settlement conference. At the adjournment of the meeting, Trilogy was to provide Aurora with a detailed accounting before proceeding forward. The accounting provided by Trilogy was not helpful and Aurora has asked for an audit under the terms set out in the Joint Operating Agreement. Discovery is ongoing in this case and no trial date has been set at this time. Victory does not believe that all of Plaintiff's claims have merit, and thus an audit is needed before proceeding any further.
The parties entered into a Settlement Agreement and Release on November 20, 2015 and an Agreed Order to Dismiss with Prejudice was granted on November 24, 2015.
Cause No. 50,916; Trilogy Operating Inc. v. Aurora Energy Partners; In the 118th Judicial District Court of Howard County, Texas.
This lawsuit was filed on January 6, 2016. This lawsuit alleges causes of action for a suit on a sworn account, breach of contract and a suit to foreclose on liens regarding the drilling and completion of seven wells. Aurora filed an answer on January 29, 2016. Trilogy filed a Motion for Partial Summary Judgment on March 23, 2016 to which Aurora will respond. Discovery is ongoing in this case and no trial date has been set at this time.
The potential liability of Aurora is the $123,354 (the costs associated with the wells) and attorney's fees.
Cause No. 2015-05280; TELA Garwood Limited, LP. v. Aurora Energy Partners, Victory Energy Corporation, Kenneth Hill, David McCall, Robert Miranda, Robert Grenley, Ronald Zamber, and Patrick Barry; In the 164th District Court of Harris County, Texas.
This lawsuit was filed on January 30, 2015 and supplemented on March 4, 2015. This lawsuit alleges breach of contract regarding a Purchase and Sale Agreement that TELA Garwood Limited, LP and Aurora Energy Partners entered into on June 30, 2014. A first closing was held on June 30, 2014 and a purchase price adjustment payment was made on July 31, 2014. Between these two dates Aurora paid TELA approximately $3,050,133. A second closing was to take place in September, however several title defect were found to exist. The title defects could not be cured and a purchase price reduction could not be agreed upon by the parties in relation to the title defects, therefore, the second closing was terminated by TELA. Aurora and Victory have filed an answer in this case. Both parties have filed opposing motions for summary judgment and are awaiting a hearing date from the court. If this case is not resolved by summary judgment or by settlement, then a trial date has been set for August 2016.

Item 4. MINE SAFETY DISCLOSURE

Not applicable.

PART II

Item 5. Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common stock is currently quoted on the OTC Markets under the symbol "VYEY." The following table sets forth the high and low bid information for each quarter for the years ended December 31, 2015 and 2014. The information reflects prices between dealers, and does not include retail markup, markdown, or commission, and may not represent actual transactions.

		Bid Prices	
Fiscal Year Ended December 31,	Period	High	Low
2015	First Quarter	$0.40	$0.13
	Second Quarter	$0.32	$0.14
	Third Quarter	$0.37	$0.07
	Fourth Quarter	$0.30	$0.11
2014	First Quarter	$0.51	$0.10
	Second Quarter	$0.39	$0.24
	Third Quarter	$0.49	$0.22
	Fourth Quarter	$0.43	$0.05

Holders

As of December 31, 2015, the low and high bid prices for our common stock on the OTC Market was $0.13 and $.40, respectively. As of December 31, 2015, there were approximately, 1,417 holders of record of our common stock.

The transfer agent for our common stock is Transfer Online, Inc., 512 SE Salmon Street, Portland, Oregon 97214.

Dividend and Distributions Policy

We have not paid any cash dividends on our common stock and do not expect to do so in the foreseeable future. We intend to apply our earnings, if any, in expanding our operations and related activities. The payment of cash dividends in the future will be at the discretion of the board of directors and will depend upon such factors as earnings levels, capital requirements, our financial condition and other factors deemed relevant by the board of directors.

Under the terms of the Second Amended Partnership Agreement of Aurora, Navitus earns a net profits interest and proceeds from asset sales with respect to its 50% partnership interest in Aurora. Any distributions of the net profits interest and proceeds from asset sales to the partners must be approved by Victory, as managing partners and Victory and Navitus as the owners of 100% of the partnership interests. The accumulated net deficits of Navitus, along with historical contributions, net of distributions, are reported as non-controlling interests in the equity section of the consolidated financial statements.

Under the terms of Aurora's Seconded Amended Partnership Agreement, Navitus Partners, LLC, a partner of Navitus Energy Group earns a preferred return distribution of 10% based upon capital contributions to Aurora used by Victory to acquire or develop oil and gas prospects or related enterprises on behalf of Aurora. The preferred return distribution is in addition to and does not reduce any net profits or asset sale proceeds interests.

The table below summarizes the net profit distributions, proceeds of asset sales and preferred return distributions paid to Navitus Energy Group during the years ended December 31, 2015 and 2014, respectively.

Payments Made to Navitus Energy Group	The Year Ended December 31,	
	2015	2014
Distributions of Aurora Net Profits	$—	$86,516
Proceeds from the Sale of Aurora Assets	—	219,030
Preferred Distributions Due to Navitus Partners, LLC	—	341,876
Total Distributions Earned By Navitus Energy Group	$—	647,422

Securities Authorized for Issuance Under Equity Compensation Plans

See Item 12, “Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.”

Recent Sales of Unregistered Securities

During the twelve months ended December 31, 2015, we issued warrants to purchase shares of common stock at exercise prices ranging from $.18 to $.34 to Navitus in consideration of capital contributions by Aurora as follows:

Period	Investment	Warrants
First quarter ended March 31, 2015	$1,925,000	1,925,000
Second quarter ended June 30, 2015	$250,000	250,000
Third quarter ended September 30, 2015	$436,000	436,000
Fourth quarter ended December 31, 2015	$306,000	306,000
Totals	$2,917,000	2,917,000

We relied on the exemption from registration relating to offerings that do not involve any public offering pursuant to Section 4(a) (2) under the Securities Act and/or Rule 506 of Regulation D of the Securities Act. We believe that each investor had adequate access to information about us through the investor’s relationship with us.

Purchases of Equity Securities

We did not purchase any of our own common stock during the year ended December 31, 2015.

Item 6. SELECTED FINANCIAL DATA

We are a “smaller reporting company” as defined by Rule 12b-2 under the Securities Exchange Act, and as such, are not required to provide the information required under this Item.

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

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. This section should be read in conjunction with our consolidated financial statements and the accompanying notes included elsewhere in this report. Statements in our discussion may be forward-looking statements. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause future production, revenues and expenses to differ materially from our expectations.

The following is management’s discussion and analysis of certain significant factors that have affected certain aspects of our financial position and results of operations during the periods included in the accompanying audited consolidated financial statements.

General Overview

We are independent growth-oriented oil and gas exploration and production company based in Austin, Texas, with additional resources located in Midland, Texas. The company has historically been focused on the acquisition and development of unconventional resource play opportunities in the Permian Basin, the Eagle Ford shale of South Texas and other strategically important areas that offer predictable economic outcomes and long-lived reserve characteristics, however we will also pursue opportunistic acquisition in other areas of the country. The current company asset portfolio includes both vertical and horizontal wells in prominent formations such as the Eagle Ford, Austin Chalk, Woodbine, Spraberry, Wolfcamp, Wolfberry, Mississippian, Cline, Fusselman and Ellenberger. We are focused on creating shareholder value by rapidly growing conventional oil and liquids-rich natural gas reserves and cash-flow via continued low-risk vertical well development on existing properties, as well as through the acquisition of new economically strong producing properties. This focus on returns is achieved by targeting predictable conventional and resources plays that provide favorable operating environments and lifting costs.

We have carefully assembled a management team with more than 130 years of direct and relevant oil and gas experience, who also hold extensive industry relationships to help grow the company. We also utilize a team of third-party professionals on an as-needed basis. This team includes geologists for prospect evaluation and assessment and reservoir engineering resources for the analysis of current and new properties. Reserve reporting is performed by a third-party engineer located in Midland, Texas. Each independent operator utilized by the company also has their own array of experts tailored for the specific formations and well completion techniques of each property the company holds an interest in. We strategically utilize both internal capabilities and strategic industry relationships to acquire non-operated, high-grade working interest positions in predictable, low-to-moderate risk oil and gas prospects. To help grow the company and lower field level operating expenses, we also plan to build-out an internal operating team in the near-future.

At the end of 2015, we held a working interest in 37 completed wells located in Texas and New Mexico, predominantly in the Permian Basin of West Texas and the Eagle Ford area of south Texas.

Moving forward, we plan to utilize all available capital sources to complete acquisition targets that hold proved producing assets and future proven undeveloped drilling locations, with competitive economics in today's market. Although we are currently a non-operator, we do anticipate building-out internal operating capabilities in 2016. As has been previously disclosed, we are actively reviewing prospects for acquisition.

We have a focus on oil and liquids rich gas.

Going Concern

As presented in the consolidated financial statements, Company has incurred a net loss attributable to Victory Energy Corporation of $4,905,518 during the twelve months ended December 31, 2015, and losses are expected to continue in the near term. The accumulated deficit at December 31, 2015 was $44,289,126. We have been funding its operations from contributions made by Aurora, and the Aurora bank credit facility, and the sale of the Lightnin' properties and advances from affiliated parties. Management anticipates that significant additional capital expenditures will be necessary to develop our oil and natural gas properties, which consist of proved and unproved reserves, some of which may be non-producing, before significant positive operating cash flows will be achieved.

Management is pursuing business partnering arrangements for the acquisition and development of its properties as well as debt and equity funding through private placements and other sources. Without outside investment from the sale of equity securities, debt financing or partnering with other oil and natural gas companies, operating activities and overhead expenses will be reduced to a pace that will match available operating cash flows.

The accompanying consolidated financial statements are prepared as if we will continue as a going concern. The consolidated financial statements do not contain adjustments, including adjustments to recorded assets and liabilities, which might be necessary if we were unable to continue as a going concern.

Results of Operations

Comparison of Year Ended December 31, 2015 to Year Ended December 31, 2014

Revenues: All of our revenue was derived from the sale of oil and natural gas. Revenues consist of the proceeds of sales, net of royalty, and gas transportation deductions. Our net revenue decreased $44,670, or 6.4%, for the twelve months ended December 31, 2015, from $695,318 for the twelve months ended December 31, 2014. The decrease is primarily the result of the change in prices we receive for the sale of oil and natural gas. The average price per barrel of oil decreased from $71.16 for the twelve months ended December 31, 2014 to $45.72 for the twelve months ended December 31, 2015. Similarly, the average price per Mcf decreased from $5.09 for the twelve months ended December 31, 2014 to $2.51 for the twelve months ended December 31, 2015 . The decreases in sales price for revenues were partially offset by oil production increases from 6,509 to 12,152 barrels for the twelve months ended December 31, 2015.

Lease Operating Expenses: Lease operating expenses, which include the operating expenses of obtaining the oil and natural gas, decreased $30,407 or 16.0% to $159,800 for the twelve months ended December 31, 2015 from $190,207 for the twelve months ended December 31, 2014. The decrease in lease operating expenses reflects the change in the aggregate net working interests held by Aurora in oil and gas producing properties, as well as the lower operating costs of the Eagle Ford area wells.

Production Taxes: Production taxes are charged at the well head for the production of gas and oil. Production taxes decreased $2,163 or 6.2% to $32,704 for the twelve months ended December 31, 2015. The decrease is reflective of the change in oil and gas prices year to year.

Exploration and Dry Hole Costs: Dry Hole costs decreased $53,838 or 95.5% to $2,513 for the twelve months ended December 31, 2015 from $56,351 for the twelve months ended December 31, 2014. The decrease in Exploration and Dry Hole Costs is reflective of costs associated with wells in which we hold proportionally lower net working interests, as well as a decrease in exploration drilling in 2015.

General and Administrative Expense: General and administrative expenses increased $1,702,383 or 63.3% to approximately $4,389,788 for the year ended December 31, 2015 from approximately $2,687,405 for the year ending December 31, 2014. The increase is due to continued efforts to expand our operations, become timely with all SEC filings and asset related transactions, as well as share based compensation costs and professional fees associated with the Lucas business combination transaction.

Depletion, Depreciation, and Amortization: Depletion, depreciation, and amortization expenses increased $206,209 or 47.9% to $637,121 for the twelve months ended December 31, 2015 from $430,912 for the twelve months ended December 31, 2014. The increase reflects the increase in the volume of oil and natural gas production during the respective periods coupled with downward reserve adjustments.

Impairment of Oil and Natural Gas Properties: Impairment of oil and natural gas properties decreased $2,853,994 or 76.7% to $867,048 from $3,721,042 for the twelve months ended December 31, 2015. Impairment changes during the year ended December 31, 2015 are reflective of the overall continued decline in commodity prices and the subsequent decline in the fair market value of the Company's assets.

Gain on Sale of Oil and Natural Gas Properties: Gain on sale of oil and natural gas properties decreased $2,170,725 or 100.0% for the twelve months ended December 31, 2015. We did not sell any assets during the twelve months ended December 31, 2015. We sold our Lightnin' properties in June 2014 for approximately $4 million.

Management Fee Income: Management fee income decreased $82,757 or 91.2% for the twelve months ended December 31, 2015 compared to the twelve months ended December 31, 2014. This decline resulted from lower management fee billings to the Navitus Energy Group.

Interest Expense: Interest expense increased $47,287 to $112,468 for the twelve months ended December 31, 2015 from $65,181 for the twelve months ended December 31, 2014. The increase resulted from our entrance into the credit facility in place for all of 2015 versus only eight months in 2014.

Gain from Settlement Agreement: The Company recorded a gain from settlement agreement related to the settlement agreement on certain wells in the Fairway field which the Company had been initially billed for that it elected not to participate in by the operator. Based upon the terms of the settlement entered in November 2015, no payment was required to the operator. The associated joint interest billing amounts were removed from the Company's books and the associated amount of $637,248 was recognized as a gain in the fourth quarter operations in 2015. Additional information is included in the Company's Footnotes to the Consolidated Financial Statements - Note 5.

Income Taxes: There is no provision for income tax expenses recorded for either the twelve months ended December 31, 2015 or ended December 31, 2014 due to the expected net operating losses, which we refer to as NOL, of both years.

The realization of future tax benefits is dependent on our ability to generate taxable income within the NOL carry forward period. Given our history of net operating losses, management has determined that it is more-likely-than-not we will not be able to realize the tax benefit of the carry forwards. Current standards require that a valuation allowance thus be established when it is more likely than not that all or a portion of deferred tax assets will not be realized.

Net Loss: Net losses increased $676,381 or 16.0% to $4,905,518 for the twelve months ended December 31, 2015 from a net loss of $4,229,137 for the twelve months ended December 31, 2014. The net loss attributable to Victory increased $967,368 or 30.1% to $4,177,300 for the twelve months ended December 31, 2015, after taking into account the loss attributable to non-controlling interest.

During the year ended December 31, 2015, as with the year ended December 31, 2014, we did not generate positive cash flow from on-going operations. As a result, we funded our operations through the private sale of equity and the issuance of our securities in exchange for services, and loans from affiliates.

Liquidity and Capital Resources

Our cash and cash equivalents, total current assets, total assets, total current liabilities, and total liabilities as of December 31, 2015 as compared to December 31, 2014, are as follows:

	December 31, 2015	December 31, 2014
Cash	$ 2,384	$ 2,941
Total current assets	$ 180,392	$ 190,719
Total assets	$ 1,008,997	$ 1,203,713
Total current liabilities	$ 3,635,248	$ 2,632,043
Total liabilities	$ 3,730,016	$ 2,672,536

At December 31, 2015, we had a working capital deficit of $3,454,856, compared to a working capital deficit of $2,441,324 at December 31, 2014. Current liabilities increased to $3,635,248 at December 31, 2015 from $2,632,043 at December 31, 2014 primarily due to the current payable balances associated general and administrative expenses associated with the Lucas transaction, as well as litigation costs related to the Fairway asset acquisition issues. An additional $680,000 is associated with the current portion of long term debt respective to the Texas Capital Bank credit facility.

We had a $4,905,518 net loss, of which $3,166,665 was in non-cash changes and changes to working capital accounts, resulting in $1,738,853 net cash used by operating activities. This compares to cash used by operating activities for the twelve months ended December 31, 2014 of $1,137,222 after the net loss for the period of $4,229,137 was decreased by $3,091,915 in non-cash charges and changes to the working capital accounts.

Net cash used in investing activities, excluding exploration-related charges charged directly to income for the twelve months ended December 31, 2015 was $1,058,704. This was for the drilling and completion of Eagle Ford property wells. This compares to $50,804 of net cash used by investing activities for the twelve month period ended December 31, 2014 which included, $841,270 for the drilling and completion of wells, $3,214,872 for the acquisitions of oil and gas properties, $22,577 for lease renewals, $3,710 for additions to furniture and fixtures less $4,031,625 of proceeds from the sale of oil and natural gas properties.

Net cash provided by financing activities for the twelve months ended December 31, 2015 was $2,797,000, which includes $2,917,000 of contributions from Navitus; offset by $120,000 in principal payments on debt financing. This compares to the $1,170,109 in cash provided by financing activities during the twelve months ended December 31, 2014, which includes $1,140,000 of contributions from Navitus and $1,233,000 in proceeds from debt financing; offset by $647,422 in distributions to non-controlling interest owners, $122,469 in debt financing costs, and $433,000 in principal payments on debt financing.

Recent Accounting Pronouncements

In February 2015, the Financial Accounting Standards Board, which we refer to as FASB, issued Accounting Standards Update, which we refer to as ASU, 2015-02, "Consolidation (Topic 810): Amendments to the Consolidation Analysis." ASU 2015-02 affects reporting entities that are required to evaluate whether they should consolidate certain legal entities. ASU 2015-02 is effective for periods beginning after December 15, 2015 with early adoption permitted. We are currently evaluating the new guidance and has not determined the impact this standard may have on its financial statements.

In May 2014, the FASB issued ASU 2014-09, "Revenue from Contracts with Customers (Topic 606)," which supersedes the revenue recognition requirements in Accounting Standards Codification, which we refer to as ASC, Topic 605, "Revenue Recognition," and most industry-specific guidance. ASU 2014-09 is based on the principle that revenue is recognized to depict the transfer of 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. ASU 2014-09 also requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts. ASU 2014-09 applies to all contracts with customers except those that are within the scope of other topics in the FASB ASC. The new guidance is effective for annual reporting periods beginning after December 15, 2017 for public companies. Early adoption is not permitted. Entities have the option of using either

a full retrospective or modified approach to adopt ASU 2014-09. We are currently evaluating the new guidance and has not determined the impact this standard may have on its financial statements or decided upon the method of adoption.
In April 2014, the FASB issued ASU 2014-08, "Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity." ASU 2014-08 prospectively changes the criteria for reporting discontinued operations while enhancing disclosures around disposals of assets whether or not the disposal meets the definition of a discontinued operation. ASU 2014-08 is effective for annual and interim periods beginning after December 31, 2014 with early adoption permitted but only for disposals that have not been reported in financial statements previously issued. The impact of this guidance on our consolidated financial statements will depend on the size and nature of ourdisposal transactions in the future, which we cannot accurately predict. Several of our past dispositions that were treated as discontinued operations may not have been classified as such had the new guidance been in effect.

Summary of Critical Accounting Policies

Consolidation Policy

Our management, in considering accounting policies pertaining to consolidation, has reviewed the relevant authoritative guidance ASC 810. We follow this authoritative, in assessing whether the rights of the non-controlling interests should overcome the presumption of consolidation when a majority voting, or controlling interest in its investee “is a matter of judgment that depends on facts and circumstances.” In applying the circumstances and contractual provisions of the Partnership Agreement, management determines that the non-controlling rights do not, individually or in the aggregate, provide for the non-controlling interest to “effectively participate in significant decisions that would be expected to be made in the ordinary course of business.” The rights of the non-controlling interest are protective in nature.

Use of Estimates

The preparation of consolidated financial statements in conformity with U.S. generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the periods reported. Actual results could differ from these estimates.

Significant estimates include volumes of oil and natural gas reserves used in calculating depletion of proved oil and natural gas properties, future net revenues and abandonment obligations, impairment of proved and unproved properties, future income taxes and related assets and liabilities, the fair value of various common stock, warrants and option transactions, and contingencies. Oil and natural gas reserve estimates, which are the basis for unit-of-production depletion and the calculation of impairment, have numerous inherent uncertainties. The accuracy of any reserve estimate is a function of the quality of available data, the engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. In addition, reserve estimates are vulnerable to changes in wellhead prices of crude oil and natural gas. Such prices have been volatile in the past and can be expected to be volatile in the future.

These significant estimates are based on current assumptions that may be materially affected by changes to future economic conditions such as the market prices received for sales of volumes of oil and natural gas, interest rates, the fair value of our common stock and corresponding volatility, and our ability to generate future taxable income. Future changes to these assumptions may affect these significant estimates materially in the near term.

Oil and Natural Gas Properties

We account for investments in oil and natural gas properties using the successful efforts method of accounting. Under this method of accounting, only successful exploration drilling costs that directly result in the discovery of proved reserves are capitalized. Unsuccessful exploration drilling costs that do not result in an asset with future economic benefit are expensed. All development costs are capitalized because the purpose of development activities is considered to be building a producing system of wells, and related equipment facilities, rather than searching for oil and natural gas. Items charged to expense generally include geological and geophysical costs. Capitalized costs for producing wells and associated land and other assets are depleted using a Units of Production methodology based on the proved, developed reserves and calculated on a by well basis, based upon reserve reports prepared by an independent petroleum engineer in accordance with SEC rules.

The net capitalized costs of proved oil and natural gas properties are subject to an impairment test which compares the net book value of assets, based on historical cost, to the undiscounted future cash flow of remaining oil and natural gas reserves based on current economic and operating conditions. Impairment of an individual producing oil and natural gas field is first determined by comparing the undiscounted future net cash flows associated with the proved property to the carrying value of the underlying property. If the cost of the underlying property is in excess of the undiscounted future net cash flows the carrying cost of the impaired property is compared to the estimated fair value and the difference is recorded as an impairment loss. Management's estimate of fair value takes into account many factors such as the present value discount rate, pricing, and when appropriate, possible and probable reserves when activities justified by economic conditions and actual or planned drilling or other development.

Under the successful efforts method of accounting, the depletion rate is the current period production as a percentage of the total proved producing reserves. The depletion rate is applied to the net book value of property costs to calculate the depletion expense. Proved reserves materially impact depletion expense. If the proved reserves decline, then the depletion rate (the rate at which we record depletion expense) increases, reducing net income.

We depreciate other property and equipment using the straight-line method based on estimated useful lives ranging from five to 10 years.

Long-lived Assets

We review our long-lived assets and proved oil and natural gas properties for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable in accordance with the applicable ASC standard. Proved oil and natural gas assets are evaluated for impairment at least annually. If the carrying amount of the asset, including any intangible assets associated with that asset, exceeds its estimated future undiscounted net cash flows, we will recognize an impairment loss equal to the difference between its carrying amount and our estimated fair value. The fair value used to calculate the impairment for producing oil and natural gas field that produces from a common reservoir is first determined by comparing the undiscounted future net cash flows associated with total proved properties to the carrying value of the underlying evaluated property. If the cost of the underlying evaluated property is in excess of the undiscounted future net cash flows, the future net cash flows discounted at 10%, which we believe approximates fair value, we will determine the amount of impairment.

For unproved property costs, management reviews these investments for impairment on a property-by-property basis if a triggering event should occur that may suggest that impairment may be required.

Stock Based Compensation

We adopted the ASC standard related to stock compensation to account for its warrants and options issued to employees, directors, officers and directors. The fair value of common warrants granted is estimated at the date of grant using the Black-Scholes option pricing model by using the historical volatility of our stock. The calculation also takes into account the common stock fair market value at the grant date, the exercise price, the expected life of the common stock option or warrant, the dividend yield and the risk-free interest rate.

From time to time we may issue warrants and restricted stock to acquire goods or services from third parties. Restricted stock, options or warrants issued are recorded on the basis of their fair value, which is measured as of the date issued. In accordance with the standard, the options or warrants are valued using the Black-Scholes option pricing model on the basis of the market price of the underlying equity instrument on the "valuation date," which for warrants related to contracts that have substantial disincentives to non-performance, is the date of the contract, and for all other contracts is the vesting date. Expense related to the options and warrants is recognized on a straight-line basis over the shorter of the period over which services are to be received or the vesting period.

Earnings per Share

Basic earnings per share, which we refer to as EPS, is computed by dividing net income (loss) attributable to controlling interests by the weighted-average number of shares of common stock outstanding during the period. Diluted earnings per share takes into account the dilutive effect of potential common stock that could be issued by us in conjunction with stock awards that have been granted to directors and employees. In accordance with ASC 260, Earnings Per Share, awards of nonvested shares shall be considered outstanding as of the respective grant dates for purposes of computing diluted EPS even though their exercise is contingent upon vesting.

Income Taxes

We account for income taxes in accordance with ASC 740 "Income Taxes" which requires an asset and liability approach for financial accounting and reporting of income taxes. Deferred income taxes reflect the impact of temporary differences between the amount of assets and liabilities for financial reporting purposes and such amounts as measured by tax laws and regulations. Deferred tax assets include tax loss and credit carry forwards and are reduced by a valuation allowance if, based on available evidence, it is more likely than not that some portion or all of the deferred tax assets will not be realized.
The realization of future tax benefits is dependent on our ability to generate taxable income within the carry forward period. Given our history of net operating losses, management has determined that it is likely that we will not be able to realize the tax benefit of the carry forwards. ASC 740 requires that a valuation allowance be established when it is more likely than not that all or a portion of deferred tax assets will not be realized.
Accordingly, we have a full valuation allowance against its net deferred tax assets at December 31, 2015 and December 31, 2014. Upon the attainment of taxable income by our company, management will assess the likelihood of realizing the deferred tax benefit associated with the use of the net operating loss carry forwards and will recognize a deferred tax asset at that time.

Contingencies

Liabilities and other contingencies are recognized upon determination of an exposure, which when analyzed indicates that it is both probable that an asset has been impaired or that a liability has been incurred and that the amount of such loss is reasonably estimable.

Volatility of Oil and Natural Gas Prices

Our revenues, future rate of growth, results of operations, financial condition and ability to borrow funds or obtain additional capital, as well as the carrying value of our properties, are substantially dependent upon prevailing prices of oil and natural gas. The recent drop in commodity prices has reduced our cash flows from operations.

Off-Balance Sheet Arrangements

For the years ended December 31, 2015 and 2014, we had no off-balance sheet arrangements that were reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is deemed by our management to be material to investors.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Commodity Risk

Our revenues, future rate of growth, results of operations, financial condition and ability to borrow funds or obtain additional capital, as well as the carrying value of our properties, are substantially dependent upon prevailing prices of oil and natural gas.

Volatility of Natural Gas Prices

As an indication of the dramatic way in which the price of natural gas can change, the following table provides the average price per thousand cubic feet (MCF) of gas which our company received for the periods indicated:

Three Months Ending	Average Price per MCF

March 31, 2015	$3.33
June 30, 2015	$3.15
September 30, 2015	$2.94
December 31, 2015	$2.85

Volatility of Oil Prices

The following table provides the average price per barrel of oil which we received for the periods indicated:

Three Months Ending	Average Price per Barrel
March 31, 2015	$43.57
June 30, 2015	$46.54
September 30, 2015	$41.59
December 31, 2015	$39.41

Item 8. Consolidated financial statements and Supplementary Data

The information required by this Item 8 is incorporated by reference to the Index to Consolidated Financial Statements beginning at page F-1 of this Annual Report on Form 10-K.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms and that such information is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

Pursuant to Rule 13a-15(e) under the Exchange Act, we carried out an evaluation, with the participation of our management, including the Chief Executive Officer, or CEO (our principal executive officer, and Chief Financial Officer, or CFO (our principal financial officer), of the effectiveness of our disclosure controls and procedures (as defined under Rule 13a-15(e) under the Exchange Act) as of December 31, 2015. Based upon, and as of the date of this evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were ineffective as of December 31, 2015

Management's Report on Internal Control over Financial Reporting

Because of its inherent limitations, internal control over financial reporting may not prevent or detect all misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.
A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim consolidated financial statements will not be prevented or detected on a timely basis. Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2015. Based on this assessment, our management concluded that our disclosure controls and procedures may not be effective as of December 31, 2015 and the reasonable assurance level due to material weaknesses in internal control over financial reporting.
The material weaknesses we identified relate to our inability to prepare accurate financial statements, resulting from a lack of a sufficient number of qualified personnel to timely and appropriately account for and disclose the impact of complex, non-routine transactions in accordance with GAAP. These non-routine transactions impacted the recording

of equity-based compensation, cash flow presentation, revenue, expenses, business combinations, assets, accounts payable, classification of debt, and footnote disclosures. Notwithstanding the existence of the material weaknesses, management has concluded that the consolidated financial statements included in this report present fairly, in all material respects, our financial position, results of operations and cash flows for the periods presented in conformity with GAAP.

We do not have sufficient segregation of duties within accounting functions, which is a basic internal control. Due to our size and nature, segregation of all conflicting duties may not always be possible and may not be economically feasible. However, to the extent possible, the initiation of transactions, the custody of assets and the recording of transactions should be performed by separate individuals. Management evaluated the impact of our failure to have segregation of duties on our assessment of our disclosure controls and procedures and has concluded that the control deficiency that resulted represented a material weakness. To address this material weakness, management performed additional analyses and other procedures to ensure that the consolidated financial statements included herein, fairly present, in all material respects, our financial position, results of operations and cash flows for the periods presented. In June 2014 a full-time employee serving as the Chief Financial Officer was hired. Effective July 2014, we began installing and or improving many internal control processes. This process continued during 2015.

This Annual Report on Form 10-K does not include an attestation report of our independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by our registered public accounting firm pursuant to rules of the Securities and Exchange Commission that permit us to provide only our management's report in this Annual Report on Form 10-K.

Changes in Internal Controls

There have been no changes in our internal controls over financial reporting (or deferred in Rule 13a-15(f) under the Securities Exchange Act) that occurred during the twelve months ended December 31, 2015 that materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Item 9B. Other Information

There are no other events required to be disclosed by this Item.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The following table sets forth information regarding the names, ages (as of March 31, 2016) and positions held by each of our executive officers, followed by biographies describing the business experience of our executive officers for at least the past five years. Our executive officers serve at the discretion of the board of directors.

Name	Age	Positions Held
Kenneth Hill	52	Director, Chief Executive Officer, and President
David McCall	67	Director, General Counsel
Robert Grenley	59	Director
Ronald Zamber	56	Director, Board Chairman
Patrick Barry	54	Director, Audit Committee Chairman
Fred J. Smith, Jr.*	64	Chief Financial Officer and Controller

* On April 4, 2016, the Company accepted the resignation of its Chief Financial Officer and Controller, Fred J. Smith, Jr. The resignation takes effect no later than April 15, 2016.

Kenneth Hill – Chief Executive Officer and Director

Mr. Hill was appointed CEO in January 2012. Mr. Hill previously served as Victory's Vice President and Chief Operating Officer from January 2011 to January 2012 and has been a member of the Board of Directors since April 2011. Prior to joining our company, Mr. Hill held titles of Interim CEO, VP of Operations and VP of Investor Relations for the U.S. subsidiary of a publicly traded oil and gas company on the Australian Stock Exchange.

Since 2001, Mr. Hill through his private company, has raised several million dollars of venture capital, personally invested in and consulted for a number of successful entrepreneurial ventures across a variety of industries, including oil and gas. Prior to 2001, Mr. Hill was employed for 16 years at Dell, Inc. As one of the first 20 employees at Dell he served in a variety of management positions including manufacturing, sales, marketing, and business development. Prior to joining Dell, Mr. Hill studied Business Management and Business Marketing at Southwest Texas State University (now Texas State University). While at Dell, Mr. Hill continued his education at The University of Texas Graduate School of Business Executive Education program, The Aspen Institute and the Center for Creative Leadership. He is a team builder with a unique set of proven leadership, management and technical skills.

Director Qualifications: Mr. Hill has extensive senior management and venture capital experience across a variety of industries, including oil and gas, for over 25 years.

David McCall – Board Member, Director and General Counsel

Mr. McCall became our General Counsel on June 20, 2011 and a member of our board of directors on June 20, 2011. Mr. McCall has over 35 years of experience in the oil and gas industry, and is currently a partner in The McCall Firm in Austin, Texas. Mr. McCall's law practice has centered on the upstream, midstream and downstream activities of major and independent oil companies.

His expertise encompasses all aspects of oil and gas operations. He has been instrumental in negotiating operating leases and agreements; production purchase and sale agreements; pipeline and exploration agreements.

He has been lead counsel on complex oil and gas litigation matters including disputes between interest holders in producing properties; contract and lease disputes; title controversies and other traditional oil and gas matters. He has represented clients in federal royalty valuation disputes and Minerals Management Service (MMS) administrative proceedings.

Mr. McCall is also experienced in the preparation of drilling title opinions, loan opinions, division order title opinions, and acquisition opinions. He is board-certified in oil, gas and mineral law. Mr. McCall is an author and has served as an expert witness in title matters involving oil and gas properties.
Director Qualifications: Mr. McCall has over 35 years of oil and gas industry legal and advisory experience.

In 1971, Mr. McCall received a Bachelor of Arts in marketing from McMurry University, Abilene, Texas. He graduated from Texas Tech School of Law, Lubbock, Texas in 1974. He is a Member of the Bar, State of Texas; a Life Fellow, Texas Bar Foundation; and a Founding Fellow, Austin Bar Foundation.

Robert Grenley – Board Member, Director and Audit Committee Member

Mr. Grenley became a member of our board of directors on June 1, 2010. Mr. Grenley has over 25 years of experience in financial management, business development and entrepreneurial experience. This financial experience includes 12 years managing early stage organizations with equity capital.

Mr. Grenley's broader financial management experience includes over 10 years of direct portfolio management and investment expertise including common and preferred stock, stock options, corporate and municipal bonds as well as syndicated investments and private placements.

Mr. Grenley holds a BA in Economics from Duke University.

Director Qualifications: Mr. Grenley has over 25 years of experience in financial management, business development and entrepreneurial experience.

Ronald W. Zamber, M.D. Director – Chairman of the Board and Audit Committee Member

Dr. Zamber became a member of our board of directors on January 24, 2009. Dr. Zamber is founder, Managing Director and Chairman of Visionary Private Equity Group. He brings more than 20 years of experience in corporate management and business development extending across the public, private and non-profit arenas. Dr. Zamber has helped build profitable companies in healthcare, private and public petroleum E&P, consumer products and Internet technology industries. He is a Managing Director of Navitus Energy Group, Navitus Partners and James Capital Energy.

Dr. Zamber is a Board Certified Ophthalmologist and founder of International Vision Quest, a non-profit organization that performs humanitarian medical and surgical missions, builds water treatment facilities and supports food delivery programs to impoverished communities around the world. He has served as an examiner with the American Board of Ophthalmologists and Secretariat for State Affairs with the American Academy of Ophthalmology.

He is the 2009 recipient of Notre Dame’s prestigious Harvey Foster Humanitarian Award. He now serves on the advisory board of Feed My Starving Children, one of the highest rated and fastest growing charities in the country. Dr. Zamber received his Bachelor's degree with high honors from the University of Notre Dame and his medical degree with honors from the University of Washington.

Director Qualifications: Mr. Zamber has over 20 years of experience in corporate management and business development extending across the public, private and non-profit arenas.

Patrick Barry – Board Member, Director and Audit Committee Chairman

Mr. Barry became a member of our board of directors on October 21, 2013. Prior to joining the Board, Mr. Barry served as a financial and operations consultant for our company. He is an experienced general manager with strengths in financial management, profitability improvement, strategy development, and implementing disciplined operating processes in both public and private companies.

Mr. Barry has a Bachelor of Science in Mechanical Engineering from the University of Notre Dame and a MBA in Finance from Wharton. Mr. Barry is a principal in Visionary Private Equity, a major investor in our company.

Mr. Barry is a former Managing Director of the Gigot Center for Entrepreneurial Studies at the University of Notre Dame where he was also an Adjunct Professor. Prior to Notre Dame, he spent eight years turning around Quality Dining, Inc., a publicly held restaurant company headquartered in South Bend, IN. Mr. Barry was a consultant with Andersen Consulting in their Strategic Service Group, focusing in strategy development and general management consulting.

Director Qualifications: Mr. Barry is an experienced general manager with strengths in financial management, profitability improvement, strategy development, and implementing disciplined operating processes in both public and private companies.

Fred Smith - Chief Financial Officer and Controller

Mr. Smith, has served as our Chief Financial Officer and Controller since June 2014. Prior to his appointment as our Chief Financial Officer and Controller, he worked as an independent consultant since December 2013. Prior to that, Mr. Smith worked as Senior Vice President and Chief Accounting Officer of Magnum Hunter Resources from October 2012 to September 2013. Previously, Mr. Smith served as the Corporate Controller of Pioneer Natural Resources from November 2008 to October 2012, where he was responsible for financial reporting, capital and operating expense reporting and application process controls. Mr. Smith has worked for a variety of energy companies during his career ranging from small privately held companies to major upstream entities. Mr. Smith has a B.S. in Accounting from the University of New Orleans.

Director Qualifications

Directors are responsible for overseeing our business consistent with their fiduciary duty to stockholders. This significant responsibility requires highly-skilled individuals with various qualities, attributes and professional experience. The Board believes that there are general requirements for service on our Board of Directors that are applicable to all directors and that there are other skills and experience that should be represented on the Board as a whole, but not necessarily by each director. The Board considers the qualifications of directors and director candidates individually and in the broader context of the Board's overall composition and our current and future needs.

Qualifications for All Directors

In its assessment of each potential candidate, including those recommended by stockholders, the Board considers the nominee's judgment, integrity, experience, independence, understanding of our business or other related industries and such other factors the Board determines are pertinent in light of the current needs of the Board. The Board also takes into account the ability of a director to devote the time and effort necessary to fulfill his or her responsibilities to our company.

The Board requires that each director be a recognized person of high integrity with a proven record of success in his or her field. Each director must demonstrate innovative thinking, familiarity with and respect for corporate governance requirements and practices, an appreciation of multiple cultures and a commitment to sustainability and to dealing responsibly with social issues. In addition to the qualifications required of all directors, the Board assesses intangible qualities including the individual's ability to ask difficult questions and, simultaneously, to work collegiality.

The Board does not have a specific diversity policy, but considers diversity of race, ethnicity, gender, age, cultural background and professional experiences in evaluating candidates for Board membership. Diversity is important because a variety of points of view contribute to a more effective decision-making process.

Qualifications, Attributes, Skills and Experience to be Represented on the Board as a Whole

The Board has identified particular qualifications, attributes, skills and experience that are important to be represented on the Board as a whole, in light of our current needs and business priorities.

Summary of Qualifications of Directors

Set forth below is a narrative disclosure that summarizes some of the specific qualifications, attributes, skills and experiences of our directors. For more detailed information, please refer to the biographical information for each director set forth above.

Kenneth Hill. [*]

David McCall. [*]

Robert Grenley. [*]

Ronald Zamber. [*]

Patrick Barry. [*]

Family Relationships

There are no family relationships among our directors or officers.

Involvement in Certain Legal Proceedings

To the best of our knowledge, none of our directors or executive officers has, during the past ten years:

- been convicted in a criminal proceeding or been subject to a pending criminal proceeding (excluding traffic violations and other minor offenses);
- had any bankruptcy petition filed by or against the business or property of the person, or of any partnership, corporation or business association of which he was a general partner or executive officer, either at the time of the bankruptcy filing or within two years prior to that time;
- been subject to any order, judgment, or decree, not subsequently reversed, suspended or vacated, of any court of competent jurisdiction or federal or state authority, permanently or temporarily enjoining, barring, suspending or otherwise limiting, his involvement in any type of business, securities, futures, commodities, investment, banking, savings and loan, or insurance activities, or to be associated with persons engaged in any such activity;
- been found by a court of competent jurisdiction in a civil action or by the Securities and Exchange Commission or the Commodity Futures Trading Commission to have violated a federal or state securities or commodities law, and the judgment has not been reversed, suspended, or vacated;
- been the subject of, or a party to, any federal or state judicial or administrative order, judgment, decree, or finding, not subsequently reversed, suspended or vacated (not including any settlement of a civil proceeding among private litigants), relating to an alleged violation of any federal or state securities or commodities law or regulation, any law or regulation respecting financial institutions or insurance companies including, but not limited to, a temporary or permanent injunction, order of disgorgement or restitution, civil money penalty or temporary or permanent cease-and-desist order, or removal or prohibition order, or any law or regulation prohibiting mail or wire fraud or fraud in connection with any business entity; or
- been the subject of, or a party to, any sanction or order, not subsequently reversed, suspended or vacated, of any self-regulatory organization (as defined in Section 3(a)(26) of the Exchange Act (15 U.S.C. 78c(a)(26))), any registered entity (as defined in Section 1(a)(29) of the Commodity Exchange Act (7 U.S.C. 1(a)(29))), or any equivalent exchange, association, entity or organization that has disciplinary authority over its members or persons associated with a member.

Corporate Governance and Board Composition

Our business and affairs are organized under the direction of our board of directors, which currently consists of five (5) members. The primary responsibilities of our board of directors are to provide oversight, strategic guidance, counseling and direction to our management. Our board of directors meets on a regular basis and additionally as required. Written board materials are distributed in advance as a general rule, and our board of directors schedules meetings with and presentations from members of our senior management on a regular basis and as required.

Our board of directors set schedules to meet throughout the year and also can hold special meetings and act by written consent under certain circumstances. Our board of directors met 4 times during the year ended December 31, 2015.

Limitation of Liability and Indemnification

We intend to enter into indemnification agreements with each of our directors and executive officers and certain other key employees. The form of agreement provides that we will indemnify each of our directors, executive officers, and such other key employees against any and all expenses incurred by that director, executive officer or key employee because of his or her status as one of our directors, executive officers or key employees, to the fullest extent permitted by law and our bylaws (except in a proceeding initiated by such person without board approval). In addition, the form agreement provides that, to the fullest extent permitted by law, we will advance all expenses incurred by our directors, executive officers, and such key employees in connection with a legal proceeding.

The Nevada Revised Statutes and our bylaws contain provisions relating to the limitation of liability and indemnification of directors and officers.

Our bylaws provide that we will indemnify our directors and officers to the fullest extent permitted by law, as it now exists or may in the future be amended, against all expenses and liabilities reasonably incurred in connection with their service for or on our behalf. Our bylaws provide that we shall advance the expenses incurred by a director or officer in advance of the final disposition of an action or proceeding. Our bylaws also authorize us to indemnify any of our employees or agents and permit us to secure insurance on behalf of any officer, director, employee or agent for any liability arising out of their action in that capacity, whether or not the law would otherwise permit indemnification.

We maintain Directors and Officers insurance on behalf of its directors and officers.

Shareholder Communications

Any shareholder of our company wishing to communicate to the Board of Directors may do so by sending written communication to the Board of Directors to the attention of Mr. Kenneth Hill, Chief Executive Officer, at our principal executive offices. The Board of Directors will consider any such written communication at its next regularly scheduled meeting.

Section 16(a) Beneficial Ownership Reporting Compliance:

Under the securities laws of the United States, our directors, its executive officers and any persons holding more than 10% of our common stock are required to report their ownership of our common stock and any changes in that ownership to the Securities and Exchange Commission. Specific due dates for these reports have been established by rules adopted by the SEC and we are required to report in this Annual Report on Form 10K any failure to file by those deadlines.

Based solely upon a review of Forms 3, 4, and 5, and amendments to these forms furnished to us, except as provided below, all parties subject to the reporting requirements of Section 16(a) of the Exchange Act filed all such required reports during and with respect to our 2015 fiscal year.

To the best of our knowledge, the number of late reports for Kenneth Hill was 1.

To the best of our knowledge, the number of late reports for Fred J. Smith Jr. was 0.

To the best of our knowledge, the number of late reports for David McCall was 1.

To the best of our knowledge, the number of late reports for Robert Grenley was 1.

To the best of our knowledge, the number of late reports for Ron Zamber was 1.

To the best of our knowledge, the number of late reports for Patrick Barry was 1.

Code of Ethics

As of December 31, 2015, our board of directors consists of 5 members and it is anticipated that the board of directors will not expand to include any additional members.

We do not have any "independent directors" as that term is defined under independence standards used by any national securities exchange or an inter-dealer quotation system. The board of directors has not established any committees, and accordingly, the board of directors serves as the audit, compensation, and nomination committee.

We have not adopted a code of ethics that applies to our our principal executive officer, principal financial officer, principal accounting officer and controller, or persons performing similar functions during the year ended December 31, 2015, because of the small number of persons involved in the management of our company.

Item 11. Executive Compensation

The following table sets forth information regarding compensation earned during the last two fiscal years by our Chief Executive Officer and Chief Financial Officer, which we refer to as the Named Executive Officers. No other executive officers received total compensation in excess of $100,000 in either fiscal year.

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards ($)(1)	Warrant/Option Awards ($)(1)	Non-Equity Incentive Plan Compensation ($)	All Other Compensation ($)	Total ($)
Kenneth Hill - President and Chief Executive Officer (3)	2015	215,625	—	121,850	100,050	—	—	437,525
Kenneth Hill - President and Chief Executive Officer	2014	211,667	—	121,700	51,750	—	—	385,117
Fred J. Smith, Jr. - Chief Financial Officer (2)	2015	172,500	—	—	—	—	—	172,500
Fred J. Smith, Jr. - Chief Financial Officer (2)	2014	105,000	10,000	—	45,000	—	50,000	173,750

(1) These amounts shown represent the aggregate grant date fair value for stock awards, options and warrants granted to the Named Executive Officers computed in accordance with FASB ASC Topic 718. Assumptions used in the calculation of these amounts are included in "Note 7 – Stockholders' Equity" to our audited financial statements for the fiscal year ended December 31, 2015 included in this Annual Report on Form 10-K. All outstanding stock awards were canceled as of the Emergence Date.

(2) The annual salary for Fred J. Smith, Jr. is $180,000 per year. As of December 31, 2015, Mr. Smith had only received $172,5000 of the $180,000 annual salary. The effective date of his employment is June 2, 2014. Other compensation relates to relocation expenses.

(3) The annual salary for Kenneth Hill is $220,000 per year. As of December 31, 2015, Mr. Hill had only received $215,625 of the $220,000 annual salary. The effective date of this salary is April 1, 2014.

Narrative Disclosure to Summary Compensation Table

We have not historically adopted any formal policies or procedures regarding executive compensation. Instead, compensation decisions are made in accordance with the terms of employment agreements with our executive officers, or on an ad hoc basis and at the discretion of the Board. We have entered into employment agreements with our Named Executive Officers.

The following details the terms of the employment agreements:

On May 27, 2014, we entered into an Employment Agreement with Fred J. Smith, Jr., wherein Mr. Smith, Jr. agreed to serve as the Chief Financial Officer of our company. The term of the employment agreement began on June 2, 2014, and will end upon notice by either party. Mr. Smith, Jr. will receive a base annual salary of $180,000 per year and he will participate in our employee benefit plans made available to its executive officers generally. On June 3, 2015 the employment agreement was amended to revise certain responsibilities and allow Mr. Smith to relocate to Louisiana. In addition, the remaining of stock options awarded Mr. Smith under the Company's Long Term Incentive Plan when hired would fully vest upon his last day of employment, and Mr. Smith's medical health insurance will continued to be paid by the Company for a minimum of 60 days-notice upon hiring of a replacement CFO.

On January 7, 2011, we entered into an Employment Agreement with Kenneth Hill, wherein Mr. Hill agreed to serve as Vice President and Chief Operating Officer of our company. The term of the employment agreement began on January 10, 2011, and will end upon notice by either party. Mr. Hill will receive a base annual salary of $225,000 per year and he will participate in our employee benefit plans made available to its executive officers generally.

We made the following grants of awards under the Victory Energy Corporation 2014 Long Term Incentive Plan (the "Incentive Plan") to the Named Executive Officers:
On April 23, 2014, Mr. Hill was granted an award (the "April Stock Grant") of 300,000 shares of our common stock under the Incentive Plan. The 300,000 shares of common stock granted to Mr. Hill in the April Stock Grant are 100% vested as of the date of grant.

On April 23, 2014, we granted Mr. Hill an option, under the Incentive Plan, to purchase 150,000 shares of our common stock at an option price of $0.35, which was the fair market value as of the date of grant. The option was 100% vested on the date of grant. The option will terminate on April 23, 2020.

On June 30, 2014, Mr. Hill was also granted an award (the “June Stock Grant”) of 20,000 shares of our common stock under the Incentive Plan. The 20,000 shares of our common stock granted to Mr. Hill in the June Stock Grant are 100% vested as of the date of grant.

On September 30, 2014, Mr. Hill was also granted an award (the “September Stock Grant”) of 20,000 shares of our common stock under the Incentive Plan. The 20,000 shares of our common stock granted to Mr. Hill in the September Stock Grant are 100% vested as of the date of grant.

On December 31, 2014, Mr. Hill was also granted an award (the “December Stock Grant”) of 20,000 shares of our common stock under the Incentive Plan. The 20,000 shares of our common stock granted to Mr. Hill in the December Stock Grant are 100% vested as of the date of grant.

On March31, 2015, Mr. Hill was also granted an award (the “March Stock Grant”) of 20,000 shares of our common stock under the Incentive Plan. The 20,000 shares of our common stock granted to Mr. Hill in the March Stock Grant are 100% vested as of the date of grant.

On August 28, 2015, Mr. Hill was also granted an award (the “August Stock Grant”) of 340,000 shares of our common stock under the Incentive Plan. The 340,000 shares of our common stock granted to Mr. Hill in the August Stock Grant are 100% vested as of the date of grant.

On August 28, 2015 we granted Mr. Hill an option, under the Incentive Plan, to purchase 375,000 shares of our common stock at an option price of $0.27, which was the fair market value as of the date of grant. The option was 100% vested on the date of grant. The option will terminate on August 28, 2020.

On October 1, 2015, Mr. Hill was also granted an award (the “October Stock Grant”) of 60,000 shares of our common stock under the Incentive Plan. The 60,000 shares of our common stock granted to Mr. Hill in the October Stock Grant are 100% vested as of the date of grant.

On December 31, 2015, Mr. Hill was also granted an award (the “December Stock Grant”) of 60,000 shares of our common stock under the Incentive Plan. The 60,000 shares of our common stock granted to Mr. Hill in the December Stock Grant are 100% vested as of the date of grant.

On June 2, 2014, Mr. Smith was granted a Nonstatutory Stock Option covering 150,000 shares of our common stock under the Incentive Plan. The option granted to Mr. Smith will have a price of $.30 and will vest over a 3-year period on each anniversary of the date of grant with 100% vesting accelerated for certain events such as a change in control of our company.

Potential Payments upon Termination or Change in Control

The Named Executive Officers are not entitled to any payments upon his termination or upon a change in control.

The employment agreements with Hill and Smith do not provide for any payments upon the termination of their employment or a change of control. All of the awards granted to Mr. Hill were 100% vested as of the time of grant and are therefore not subject to any accelerated vesting provisions upon a change of control or the termination of his employment. As such, Mr. Hill is not entitled to any payments upon a termination of his employment or a change of control. The Nonstatutory Stock Option granted to Mr. Hill under the Incentive Plan will automatically vest in its entirety upon certain events such as a change of control or a termination of his employment due to death, disability or without cause.

The Nonstatutory Stock Option granted to Mr. Smith under the Incentive Plan will automatically vest in its entirety upon certain events such as a change of control or a termination of his employment due to death, disability or without cause.

The following table further describes the potential payments upon termination or a change in control for Mr. Smith.

Fred Smith
Chief Financial Officer

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Executive Benefits and Payments Upon Termination	Voluntary Termination ($)	For cause terminated ($)	Involuntary Not for Cause Termination ($)	Death or Disability ($)	Retirement ($)	After a Change in Control
Long-Term Equity Incentives						
Nonstatutory Stock Option (Unvested and Accelerated)	—	—	—	—	—	150,000
Total	—	—	—	—	—	150,000

Outstanding Equity Awards at Fiscal Year-End

The following table sets forth certain information concerning outstanding stock awards held by the Named Executive Officers as of December 31, 2015.

	OPTION AWARDS					STOCK AWARDS			
Name - Year	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 (#)	Warrant/ Option Exercise Price ($)	Warrant/ Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested ($)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)
Kenneth Hill - President and Chief Executive Officer	60,000	—	—	$1.00	12/31/2016	—	—	—	—
Kenneth Hill - President and Chief Executive Officer	87,500	—	—	$.35	5/23/2017	—	—	—	—
Kenneth Hill - President and Chief	52,083	—	—	$.27	8/28/2019				

Executive Officer									
Fred J. Smith, Jr. - Chief Financial Officer	79,167	—	—	$.30	7/2/2017	—	—	—	—

Director Compensation

The following table sets forth the total compensation awarded to, earned by, or paid to each person who served as a director during the year ended December 31, 2015, other than a director who also served as a named executive officer. Our directors who are not executive officers do receive any cash compensation for serving on our Board. We have a policy of reimbursing our directors for their reasonable out-of-pocket expenses incurred in attending Board and committee meetings. Each director is paid for his or her director services in the form of stock awards granted quarterly for each quarter of service. These stock awards and vest immediately, at fair market value, upon date of issuance.

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($)(1)	Warrant/Option Awards ($)(1)	Total ($)
Ronald Zamber	—	126,559	—	126,559
David McCall	411,059	112,931	—	523,990
Robert Grenley	—	64,475	—	64,475
Patrick Barry	—	60,721	—	60,721

(1) These amounts shown represent the aggregate grant date fair value for stock awards, options and warrants granted to the directors computed in accordance with FASB ASC Topic 718. Assumptions used in the calculation of these amounts are included in “Note 7 – Stockholders’ Equity” to our audited financial statements for the fiscal year ended December 31, 2015 included in our annual report filed with on March 31, 2016. All outstanding stock awards were canceled as of the Emergence Date.

Narrative Disclosure of Compensation Policies and Practices as Related to Risk Management

In accordance with the requirements of Regulation S-K, Item 402(s), to the extent that risks may arise from our compensation policies and practices that are reasonably likely to have a material adverse effect on us, we are required to discuss those policies and practices for compensating our employees (including employees that are not named executive officers) as they relate to our risk management practices and the possibility of incentivizing risk-taking. We have determined that the compensation policies and practices established with respect to our employees are not reasonably likely to have a material adverse effect on us and, therefore, no such disclosure is necessary.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The following table sets forth certain information about the securities authorized for issuance under our Incentive Plan as of December 31, 2015. Options exercisable for all of the securities shown in column (a) below were granted under our Incentive Plan.

Equity Compensation Plan Information

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights[1] (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by	4,337,500	0.29	253,674

security holders			
Equity compensation plans not approved by security holders	—	—	—
Total	4,337,500	0.29	253,674

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(1) Includes options outstanding under the 2014 Long Term Incentive Plan. The total number of shares of common stock initially available for issuance under the 2014 Long Term Incentive Plan was 4,591,174. As of December 31, 2015, 3,367,500 shares of unrestricted common stock and 970,000 options were issued under the LTIP. The maximum contractual term is five years.

Security Ownership of Certain Beneficial Owners

Beneficial ownership is determined in accordance with the rules of the SEC, and generally includes voting power and/or investment power with respect to the securities held. Shares of common stock subject to options or warrants currently exercisable or exercisable within 60 days of December 31, 2015, are deemed outstanding and beneficially owned by the person holding such options or warrants for purposes of computing the number of shares and percentage beneficially owned by such person, but are not deemed outstanding for purposes of computing the percentage beneficially owned by any other person. Except as indicated in the footnotes to these tables, and subject to applicable community property laws, the persons or entities named have sole voting and investment power with respect to all shares of our common stock shown as beneficially owned by them.

The following table sets forth, as of December 31, 2015, certain information with respect to our equity securities owned or record or beneficially by (i) each officer and director of our company; (ii) each person who owns beneficially more than 5% of each class of our outstanding equity securities; and (iii) all directors and executive officer as a group:

Name and Position	Business Address	Common Stock	Vested Options	Warrants (1)	Total	Percent of Class (2)	
Kenneth Hill,	3355 Bee Caves Rd., Ste 608						
President and Chief Executive Officer	Austin, TX 78746	1,105,830	199,583	143,900	1,449,313	4.6	%
Fred J. Smith Jr.,	15121 Championship Dr.						
Chief Financial Officer and Controller	Baton Rouge, LA. 70810	—	70,833	—	70,833	0.2	%
David McCall,	3660 Stoneridge Blvd., Ste. F-102						
General Counsel, Director (3)	Austin TX 78746	880,233	—	244,150	1,124,383	3.6	%
Robert Grenley, Director	40 Loch Lane SW, Lakewood, WA 98499	441,434	—	118,600	560,034	1.8	%
Ronald Zamber, Director (4), Interim Board Chairman	1919 Lathrop Suite Fairbanks, AK 99701	5,902,210	—	2,191,281	8,093,491	25.9	%
Patrick Barry	51551 Norwich Dr.						
Audit Committee Chairman	Granger, IN 46530	817,320	—	98,400	915,720	2.9	%
All Officers and Directors	As a Group (5 Persons)	9,147,027	270,416	2,796,331	12,213,774	39.0	%

(1) All warrants are exercisable immediately

(2) Based on total shares outstanding which consists of 31,220,326 shares of common stock outstanding,627,500 vested options, and 8,622,486 unexercised warrants.

(3) Includes 145,233 shares owned by 1519 Partners LLC; David McCall is the controlling partner and of 1519 Partners LLC.

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(4) Includes 2,468,138 shares owned by Visionary Investments, LLC of which Ronald Zamber is sole member; 2,437,481 shares owned by Visionary Private Equity Group I, LP of which Ronald Zamber is chairman, and managing director, and 104,845 shares owned by James Capital Consulting of which Ronald Zamber is the managing member.

There are no classes of stock other than common stock issued or outstanding.

We are not aware of any current arrangements which will result in a change in control.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Related Party Transactions

During the year ended December 31, 2015 we incurred a total of $411,059 in legal fees with The McCall Firm. David McCall, our general counsel and a director, is a partner in The McCall Firm. The fees are attributable to litigation involving our oil and natural gas operations in Texas. As of December 31, 2015, we owed The McCall Firm approximately $371,826 for these professional services.

During the year ended December 31, 2015, a member of management made a $29,553 temporary advance to our company.

During the year ended December 31, 2015, a member of the board made a $15,000 temporary advance to our company.

During the year ended December 31, 2015, the temporary capital advances totaling $388,800 had been made by Navitus.

Our securities are not listed on a national securities exchange that has requirements as to board composition. As the securities are not so listed, the board of directors has made no determination as to whether or not any of its directors are independent directors as defined in the regulations of NASDAQ or the NYSE.

Item 14. Principal Accounting Fees and Services

Audit Fees

For the years ended December 31, 2015 and 2014 respectively, we paid $189,777 and $126,394, respectively, in fees to our principal accountants.

Tax Fees

For the fiscal years ended December 31, 2015 and 2014, respectively, we paid $2,450 and $2,742, in fees to our principal accountants for tax compliance, tax advice, and tax planning work.

All Other Fees

None.

All fees described above for the years ended December 31, 2015 and 2014, were approved by the entire board of directors.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) (1) and (2) Consolidated financial statements and Schedules

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

(a)(3) Exhibits

Refer to (b) below.

(b)	Exhibits
2.1	Purchase and Sale Agreement dated as of June 30, 2014 between TELA Garwood Limited, LP and Aurora Energy Partners. Incorporated by reference to Exhibit 2.1 of the Company’s Current Report on Form 8-K filed with the SEC on July 8, 2014.
2.2	Purchase and Sale Agreement dated as of April 30, 2014 by and among Hannathon Petroleum, LLC and the other seller parties thereto and MDC Texas Energy, LLC. Incorporated by reference to Exhibit 2.1 of the Company’s Amendment No. 1 to Quarterly Report on Form 10-QA for the quarterly period ended June 30, 2014, filed with the SEC on August 28, 2014.
3.1	Amended and Restated Articles of Incorporation of Victory Energy Corporation.*
3.11	Bylaws of Victory Energy Corporation. Incorporated by reference to Exhibit 3.10 of the Company’s Annual Report on Form 10-K filed with the SEC on March 30, 2011.
4.1	Form of the Company’s Common Stock Certificate.*

10.1	Credit Agreement dated as of February 20, 2014 between Aurora Energy Partners and Texas Capital Bank, National Association. Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K filed with the SEC on February 26, 2014.
10.2	Employment Agreement dated May 27, 2014 between Victory Energy Corporation and Fred Smith. Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K filed with the SEC on June 3, 2014.
10.3	Stock Award with Kenneth Hill dated August 13, 2014. Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K filed with the SEC on August 18, 2014.
10.4	Award Notice of Nonstatutory Stock Option with Kenneth Hill dated August 13, 2014. Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K filed with the SEC on August 18, 2014.
10.5	Nonstatutory Stock Option Agreement with Kenneth Hill dated August 13, 2014. Incorporated by reference to Exhibit 10.3 of the Company's Current Report on Form 8-K filed with the SEC on August 18, 2014.
10.6	Stock Award with Kenneth Hill dated August 13, 2014. Incorporated by reference to Exhibit 10.4 of the Company's Current Report on Form 8-K filed with the SEC on August 18, 2014.
10.7	Victory Energy Stock Award (Director) with Ralph Kehle dated August 14, 2014. Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K filed with the SEC on August 18, 2014.
10.8	Pre-Merger Collaboration Agreement among the Company, Lucas Energy, Inc., Aurora Energy Partners, Navitus Energy Group and Aurora Energy Holdings LLC, dated February 26, 2015. Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K filed with the SEC on March 3, 2015.
10.9	Pre-Merger Loan and Funding Agreement between the Company and Lucas Energy, Inc. dated February 26, 2015. Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K filed with the SEC on March 3, 2015.
10.10	Pledge Agreement between Lucas Energy, Inc., as pledgor, and the Company, as secured party, dated February 26, 2015. Incorporated by reference to Exhibit 10.3 of the Company's Current Report on Form 8-K filed with the SEC on March 3, 2015.
10.11	Contingent Pay Note by the Company in favor of Louise H. Rogers dated March 3, 2015. Incorporated by reference to Exhibit 10.4 of the Company's Current Report on Form 8-K filed with the SEC on March 3, 2015.
10.12	Amendment No. 1 to Pre-Merger Collaboration Agreement dated March 2, 2015. Incorporated by reference to Exhibit 10.5 of the Company's Current Report on Form 8-K filed with the SEC on March 3, 2015.
10.13	Amendment to Employment Agreement between Victory Energy Corporation and Fred J. Smith, Jr. *
21.1	Subsidiaries of the Registrant.*
23.1	Consent of Weaver & Tidwell LLP*

23.2	Consent of Independent Petroleum Engineer and Geologists*
31.1	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*
31.2	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*
32.1	Certification of Chief Executive Officer Pursuant to 18 U.S.C. Section 1350.*
32.2	Certification of Chief Financial Officer Pursuant to 18 U.S.C. Section 1350.*
99.1	Oil and natural gas Reserves Report prepared by Cambrian Management, Ltd. dated March 1, 2016*

101.INS	Instance Document**
101.SCH	Taxonomy Extension Schema Document**
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document**
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document**
101.LAB	XBRL Taxonomy Extension Label Linkbase Document**
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document**

* Filed herewith.
** XBRL (Extensible Business Reporting Language) information is furnished and not filed or a part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, is deemed not filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and otherwise is not subject to liability under these sections.

SIGNATURES

In accordance with Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this Annual Report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Austin, State of Texas, on this 8th day of April, 2015.

VICTORY ENERGY CORPORATION

By: /s/ Kenneth Hill
Kenneth Hill
Chief Executive Officer and Director

In accordance with the requirements of the Securities Exchange Act of 1934, this Annual 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/ Kenneth Hill Kenneth Hill	Chief Executive Officer and Director (Principal Executive Officer)	
/s/ Fred J. Smith, Jr. Fred J. Smith, Jr.	Chief Financial Officer (Principal Financial Officer)	
/s/ Ronald W. Zamber Ronald W. Zamber	Director	
/s/ David B. McCall David B. McCall	Director	
/s/ Patrick Barry Patrick Barry	Director	
/s/ Robert Grenley Robert Grenley	Director	

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of
Victory Energy Corporation

We have audited the accompanying consolidated balance sheets of Victory Energy Corporation (the Company) as of December 31, 2015 and 2014, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the years in the two-year period ended December 31, 2015. These consolidated financial statements are the responsibility of the Company'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 consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated 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 consolidated financial position of Victory Energy Corporation as of December 31, 2015 and 2014, and the results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America.

The accompanying consolidated financial statements have been prepared assuming the Company will continue as a going concern. The Company has experienced recurring losses since its inception and has an accumulated deficit. These conditions raise substantial doubt regarding the Company's ability to continue as a going concern. Management's plans in regard to these matters are described in Note 1 to the consolidated financial statements. The consolidated financial statements do not include any adjustments to reflect the possible future effects on the recoverability and classification of assets or the amounts and classification of liabilities that may result from the outcome of this uncertainty.

WEAVER AND TIDWELL, L.L.P.
April 8, 2016
Houston, Texas

VICTORY ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
December 31, 2015 and 2014

ASSETS	12/31/2015	12/31/2014
Current Assets		
Cash and cash equivalents	$2,384	$2,941
Accounts receivable - less allowance for doubtful accounts of $200,000, and $200,000 for 2015 and 2014, respectively	37,690	41,565
Accounts receivable - affiliate	131,584	124,367
Prepaid expenses	8,734	21,846
Total current assets	180,392	190,719
Fixed Assets		
Furniture and equipment	46,883	46,883
Accumulated depreciation	(24,429)	(17,965)
Total furniture and fixtures, net	22,454	28,918
Oil gas properties, net of impairment (successful efforts method)	3,033,279	2,838,573
Accumulated depletion, depreciation and amortization	(2,274,188)	(1,942,380)
Total oil and gas properties, net	759,091	896,193
Other Assets		
Deferred debt financing costs	47,060	87,883
Total Assets	$1,008,997	$1,203,713
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$1,591,764	$1,119,896
Accrued liabilities	534,619	221,209
Accrued liabilities - related parties	805,179	477,934
Liability for unauthorized preferred stock issued	9,283	9,283
Note payable	680,000	800,000
Asset retirement obligation	14,403	3,721
Total current liabilities	3,635,248	2,632,043
Other Liabilities		
Asset retirement obligations	94,768	40,493
Total long term liabilities	94,768	40,493
Total liabilities	$3,730,016	$2,672,536
Stockholders' Equity (Deficit)		
Common stock, $0.001 par value, 47,500,000 shares authorized, 31,220,326 shares and 29,202,826 shares issued and outstanding for 2015 and 2014, respectively	$31,220	$29,203
Additional paid-in capital	35,708,746	34,974,441
Accumulated deficit	(44,289,126)	(40,111,826)
Total Victory Energy Corporation stockholders' deficit	(8,549,160)	(5,108,182)
Non-controlling interest	5,828,141	3,639,359
Total stockholders' equity (deficit)	(2,721,019)	(1,468,823)
Total Liabilities and Stockholders' Equity	$1,008,997	$1,203,713

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

VICTORY ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
For the years ended December 31, 2015 and 2014

	12/31/2015	12/31/2014
Revenues		
Oil and gas sales	$650,648	$695,318
Total revenues	650,648	695,318
Operating Expenses:		
Lease operating costs	159,800	190,207
Exploration and dry hole cost	2,513	56,351
Production taxes	32,704	34,867
General and administrative	4,389,788	2,687,405
Impairment of oil and natural gas properties	867,048	3,721,042
Depreciation/depletion/amortization	637,121	430,912
Total operating expenses	6,088,974	7,120,784
Loss from operations	(5,438,326)	(6,425,466)
Other Income (Expense):		
Gain on sale of oil and gas properties	—	2,170,725
Gain from legal settlement	637,248	—
Management fee income	8,028	90,785
Interest expense	(112,468)	(65,181)
Total other income and expense	532,808	2,196,329
Loss before Tax Benefit	(4,905,518)	(4,229,137)
Tax benefit	—	—
Net loss	(4,905,518)	(4,229,137)
Less: Net loss attributable to non-controlling interest	(728,218)	(1,019,205)
Net loss attributable to Victory Energy Corporation	$(4,177,300)	$(3,209,932)
Weighted average shares, basic and diluted	29,803,358	28,453,976
Net income (loss) per share, basic and diluted	$(0.14)	$(0.11)

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

VICTORY ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the years ended December 31, 2015 and 2014

	12/31/2015	12/31/2014
CASH FLOWS FROM OPERATING ACTIVITIES		
Net loss	$(4,905,518)	$(4,229,137)
Adjustments to reconcile net loss to net cash used in operating activities		
Accretion and revisions of asset retirement obligations	66,172	3,360
Amortization of debt discount and financing warrants	40,823	34,586
Depletion, depreciation, and amortization	570,337	430,912
Gain on settlement of asset retirement obligation	(3,721)	—
Gain on sale of oil and gas properties	—	(2,170,725)
Gain from legal settlement agreement	(637,248)	—
Impairment of oil and natural gas properties	867,048	3,721,042
Stock based compensation	567,112	490,174
Stock grants in exchange for services	169,210	81,667
Change in operating assets and liabilities		
Accounts receivable	3,875	74,977
Accounts receivable - affiliate	(7,217)	(105,796)
Prepaid expense	13,112	16,817
Accounts payable	876,507	131,213
Accounts liabilities - related parties	327,245	359,392
Accrued liabilities	313,410	24,296
Net cash used in operating activities	(1,738,853)	(1,137,222)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Drilling capital expenditures	(1,058,704)	(841,270)
Acquisition of oil and gas properties	—	(3,214,872)
Proceeds from sale of oil and gas properties	—	4,031,625
Renewal of leasehold costs	—	(22,577)
Purchase of furniture and fixtures	—	(3,710)
Net cash used in investing activities	(1,058,704)	(50,804)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Non-controlling interest contributions	2,917,000	1,140,000
Non-controlling interest distributions	—	(647,422)
Debt financing costs	—	(122,469)
Proceeds from debt financing	—	1,233,000
Principal payments on debt financing	(120,000)	(433,000)
Net cash provided by financing activities	2,797,000	1,170,109
Net Change in Cash and Cash Equivalents	(557)	(17,917)
Beginning Cash and Cash Equivalents	2,941	20,858
Ending Cash and Cash Equivalents	$2,384	$2,941
Supplemental cash flow information:		
Cash paid for:		
Interest	$40,053	$30,595
Non-cash investing and financing activities:		
Asset retirement obligation	$63,338	$3,721

Accrued capital expenditures	$293,304	$—
Drilling costs	$—	$637,248
Acquisition of properties	$—	$182,250

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

VICTORY ENERGY CORPORATION AND SUBSIDARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS DEFICIT
For the years ended December 31, 2015 and 2014

	Common Stock $0.001 Par Value Number	Amount	Additional Paid In Capital	Accumulated Deficit	Non-controlling Interest	Total Equity (Deficit)
Balance, December 31, 2013	27,563,619	$27,564	$34,404,239	$(36,901,894)	$4,165,986	$1,695,895
Contributions from noncontrolling interest owners	—	—	—	—	1,140,000	1,140,000
Distributions to noncontrolling interest owners	—	—	—	—	(647,422)	(647,422)
Stock awards granted	1,350,000	1,350	90,885	—	—	92,235
Stock based compensation	—	—	397,939	—	—	397,939
Stock in exchange for services	350,000	350	81,317	—	—	81,667
Shares cancelled	(60,793)	(61)	61	—	—	—
Net loss	—	—	—	(3,209,932)	(1,019,205)	(4,229,137)
Balance December 31, 2014	29,202,826	$29,203	$34,974,441	$(40,111,826)	$3,639,359	$(1,468,823)
Contributions from noncontrolling interest owners	—	—	—	—	2,917,000	2,917,000
Stock awards granted	2,017,500	2,017	506,722	—	—	508,739
Stock based compensation	—	—	58,373	—	—	58,373
Stock awards and options in exchange for services	—	—	169,210	—	—	169,210
Net loss	—	—	—	(4,177,300)	(728,218)	(4,905,518)
Balance December 31, 2015	31,220,326	31,220	35,708,746	(44,289,126)	5,828,141	(2,721,019)

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

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Victory Energy Corporation and Subsidiaries
Notes to the Consolidated Financial Statements

Note 1 – Organization and Summary of Significant Accounting Policies:

Victory Energy Corporation ("Victory" or "the Company") is an independent, growth oriented oil and natural gas company engaged in the acquisition, exploration and production of oil and natural gas properties, through its partnership with Aurora Energy Partners ("Aurora"). In this report, “the Company” refers to the consolidated accounts and presentation of Victory and Aurora, with the equity of non-controlling interests stated separately. The Company is engaged in the exploration, acquisition, development, and production of domestic oil and natural gas properties. Current operations are primarily located onshore in Texas and New Mexico. The Company was organized under the laws of the State of Nevada on January 7, 1982. The Company is authorized to issue 47,500,000 shares of $0.001 par value common stock, and has 31,220,326 shares of common stock outstanding as of December 31, 2015. Our corporate headquarters are located at 3355 Bee Caves Rd. Ste. 608, Austin, Texas.

A summary of significant accounting policies followed in the preparation of the accompanying consolidated financial statements is set forth below.

Basis of Presentation and Consolidation:

Victory is the managing partner of Aurora, and holds a 50% partnership interest in Aurora. Aurora, a subsidiary of the Company, is consolidated with Victory for financial statement reporting purposes, as the terms of the partnership agreement that govern the operations of Aurora give Victory effective control of the partnership. The consolidated financial statements include the accounts of Victory and the accounts of Aurora. The Company’s management, in considering accounting policies pertaining to consolidation, has reviewed the relevant accounting literature. The Company follows that literature, in assessing whether the rights of the non-controlling interests should overcome the presumption of consolidation when a majority voting or controlling interest in its investee “is a matter of judgment that depends on facts and circumstances". In applying the circumstances and contractual provisions of the partnership agreement, management determined that the non-controlling rights do not, individually or in the aggregate, provide for the non-controlling interest to “effectively participate in significant decisions that would be expected to be made in the ordinary course of business.” The rights of the non-controlling interest are protective in nature. All intercompany balances have been eliminated in consolidation.

Non-controlling Interests:

The Navitus Energy Group ("Navitus") is a partner with Victory in Aurora. The two partners each own a 50% interest in Aurora. Victory is the Managing partner and has contractual authority to manage the business affairs of Aurora. The Navitus Energy Group currently has four partners. They are James Capital Consulting, LLC ("JCC"), James Capital Energy, LLC ("JCE"), Rodinia Partners, LLC and Navitus Partners, LLC. Although this partnership has been in place since January 2008, its members and other elements have changed since that time.

The non-controlling interest in Aurora is held by Navitus), a Texas general partnership. As of December 31, 2015, $5,828,141 was recorded as the equity of the non-controlling interest in our consolidated balance sheet representing Navitus' third-party investment in Aurora, with losses attributable to non-controlling interests of $728,218 for the year ended December 31, 2015. As of December 31, 2014, $3,639,359 was recorded as the equity of the non-controlling interest in our consolidated balance sheet representingNavitus' third-party investment in Aurora, with losses attributable to the non-controlling interests of $1,019,205 for the year ended December 31, 2014. A total of $150,000 of previously designated capital contributions by Navitus were redesignated as temporary advances in December 31, 2014 and are included in the accrued liabilities - related parties total as of December 31, 2015 and December 31, 2014.

Reclassifications:

Certain reclassifications have been made to accounts receivable - affiliates (reduction of $50,000); accrued liabilities - related parties (increase of $100,000); and additional paid in capital (reduction of $150,000) on the December 31, 2014 Consolidated Balance Sheet to conform to the presentation on the current period Consolidated Balance Sheet and reflect the proper classification of working capital advances from a member of the Navitus Energy Group. The total $100,000 advance was repaid in January 2015. These reclassifications had no impact on the net income for the year ended December 31, 2014.

Use of Estimates:

The preparation of our consolidated financial statements in conformity with U.S. Generally Accepted Accounting Principles ("GAAP") requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Estimates are used primarily when accounting for depreciation, depletion, and amortization ("DD&A") expense, property costs, estimated future net cash flows from proved reserves, cost to abandon and impaired oil and natural gas properties, taxes, accruals of capitalized costs, operating costs and production revenue, general and administrative costs and interest, purchase price allocation on properties acquired, various common stock, warrants and option transactions, and loss contingencies.

Oil and Natural Gas Properties:

We account for investments in oil and natural gas properties using the successful efforts method of accounting. Under this method of accounting, only successful exploration drilling costs that directly result in the discovery of proved reserves are capitalized. Unsuccessful exploration drilling costs that do not result in an asset with future economic benefit are expensed. All development costs are capitalized because the purpose of development activities is considered to be building a producing system of wells, and related equipment facilities, rather than searching for oil and natural gas. Items charged to expense generally include geological and geophysical costs. Capitalized costs for producing wells and associated land and other assets are depleted using a Units of Production methodology based on the proved, developed reserves and calculated on a by well basis, based upon reserve reports prepared by an independent petroleum engineer in accordance with SEC rules and guidelines.

The net capitalized costs of proved oil and natural gas properties are subject to an impairment test which compares the net book value of assets, based on historical cost, to the undiscounted future cash flow of remaining oil and natural gas reserves based on current economic and operating conditions. Impairment of an individual producing oil and natural gas field is first determined by comparing the undiscounted future net cash flows associated with the proved property to the carrying value of the underlying property. If the cost of the underlying property is in excess of the undiscounted future net cash flows, the carrying amount of the impaired property is compared to the estimated fair value and the difference is recorded as an impairment loss. Management's estimate of fair value takes into account many factors such as the present value discount rate, pricing, and when appropriate, possible and probable reserves when activities justified by economic conditions and actual or planned drilling or other development.

For unproved property costs, management reviews for impairment on a property-by-property basis if a triggering event should occur that may suggest that impairment may be required.

Capitalized acquisition costs attributable to proved oil and gas properties are depleted by field using the unit-of-production method based on proved reserves. Capitalized exploration well costs and development costs, including asset retirement obligations, are amortized similarly by field, based on proved developed reserves.

We depreciate other property and equipment using the straight-line method based on estimated useful lives ranging from five to ten years.

The Company recorded impairment expense of $867,048 and $3,721,042 for 2015 and 2014 respectively, upon determining that the oil and natural gas properties were impaired.

Asset Retirement Obligations:

The Company records the estimate of the fair value of liabilities related to future asset retirement obligations ("ARO") in the period the obligation is incurred. Asset retirement obligations relate to the removal of facilities and tangible equipment at the end of an oil and natural gas property's useful life. The application of this rule requires the use of management's estimates with respect to future abandonment costs, inflation, market risk premiums, useful life and cost of capital and required government regulations. U.S. GAAP requires that the estimate of our asset retirement obligations does not give consideration to the value the related assets could have to other parties.

The following table is a reconciliation of the ARO liability for the twelve months ended December 31, 2015 and 2014.

	Years Ended December 31,	
	2015	2014
Asset retirement obligation at beginning of period	$44,214	$51,954
Liabilities incurred	2,506	3,721
Revisions to previous estimates and sales of properties	60,832	(14,821)
Liabilities on properties sold or settled	(3,721)	—
Accretion expense	5,340	$3,360
Asset retirement obligation at end of period	$109,171	$44,214

Other Property and Equipment:

Our office equipment in Austin, Texas is being depreciated on the straight-line method over the estimated useful life of five to seven years.

Cash and Cash Equivalents:

The Company considers all liquid investments with original maturities of three months or less from the date of purchase that are readily convertible into cash to be cash equivalents. The Company had no cash equivalents at December 31, 2015 and 2014.

Accounts Receivable:

Our accounts receivable are primarily from purchasers of natural gas and oil and exploration and production companies which own an interest in properties we operate.

Allowance for Doubtful Accounts:

The Company recognizes an allowance for doubtful accounts to ensure trade receivables are not overstated due to uncollectibility. Allowance for doubtful accounts are maintained for all customers based on a variety of factors, including the length of time receivables are past due, macroeconomic conditions, significant one-time events and historical experience. An additional allowance for individual accounts is recorded when we become aware of a customer’s inability to meet its financial obligations, such as in the case of bankruptcy filings or deterioration in the customer’s operating results or financial position. If circumstances related to customers change, estimates of the recoverability of receivables would be further adjusted. As of December 31, 2015 and 2014, the Company has deemed $200,000 from the sale of oil and gas properties associated with the Jones County prospect, to be doubtful and thus, has recorded this amount as an allowance for doubtful accounts.

Fair Value:

At December 31, 2015 and 2014, the carrying value of the Company's financial instruments such as prepaid expenses and payables approximated their fair values based on the short-term maturities of these instruments. The carrying value of other liabilities approximated their fair values because the underlying interest rates approximate market rates at the balance sheet dates. Management believes that due to the Company's current credit worthiness, the fair value of debt could be less than the book value; however, due to current market conditions and available information, the fair value of such debt is not readily determinable. Financial Accounting Standard Board ("FASB") ASC Topic 820 established a hierarchical disclosure framework associated with the level of pricing observability utilized in measuring fair value. This framework defined three levels of inputs to the fair value measurement process and requires that each fair value measurement be assigned to a level corresponding to the lowest level input that is significant to the fair value measurement in its entirety. The three broad levels of inputs defined by FASB ASC Topic 820 hierarchy are as follows:

Level 1 - quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date;

Leve1 2 - inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Leve1 2 input must be observable for substantially the full term of the asset or liability; and

Leve1 3 - unobservable inputs for the asset or liability. These unobservable inputs reflect the entity's own assumptions about the assumptions that market participants would use in pricing the asset or liability and are developed based on the best information available in the circumstances (which might include the reporting entity's own data).

The initial measurement of asset retirement obligations is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with proved oil and gas properties. Inputs used in the calculation of asset retirement obligations include plugging costs and reserve lives, which are considered Level 3 inputs. A reconciliation of Victory’s asset retirement obligations is presented in Note 1.

During 2015, proved oil and gas properties with a carrying value of $1,640,147 were written down, based upon engineering estimates, to their fair value of $759,091 as a result of $867,048 in impairment charges. Of this impairment amount, $303,312 was taken against the Eagle Ford properties, $297,212 was taken against the Adams Baggett properties, and $99,682 was taken against the Fairway properties. In addition, the Company has written off the entire balance associated with undeveloped properties, or $166,842. During 2014, proved oil and gas properties with a carrying value of $792,530 were written down, based upon engineering estimates, to their fair value of $658,509 as a result of $3,721,041in impairment charges. Of this amount, additional impairment charges of $3,587,020 were taken on the Fairway properties, which were written down from a carrying value of $3,826,525 to the fair value of $239,505. Significant Level 3 assumptions associated with the calculation of discounted cash flows used in the impairment analysis include Victory’s estimate of future crude oil and natural gas prices, production costs, development expenditures, anticipated production of proved reserves, appropriate risk-adjusted discount rates and other relevant data, primarily derived from a third party independent reserve report.

Revenue Recognition:

The Company uses the sales method of accounting for oil and natural gas revenues. Under this method, revenues are recognized based on actual volumes of gas and oil sold to purchasers. The volumes sold may differ from the volumes to which the Company is entitled based on our interests in the properties. Differences between volumes sold and entitled volumes create oil and natural gas imbalances which are generally reflected as adjustments to reported proved oil and natural gas reserves and future cash flows in their supplemental oil and natural gas disclosures. If their excess takes of natural gas or oil exceed their estimated remaining proved reserves for a property, a natural gas or oil imbalance liability is recorded in the Consolidated Balance Sheets.

Concentrations:

There is a ready market for the sale of crude oil and natural gas. During 2015 and 2014, our gas field and our producing wells sold their respective gas and oil production to one purchaser for each field or well. However, because alternate purchasers of oil and natural gas are readily available at similar prices, we believe that the loss of any of our purchasers would not have a material adverse effect on our financial results. A majority of the Company’s production and reserves are from the Eagleford property in South Texas and the Permian Basin of West Texas.

Earnings per Share:

Basic earnings per share are computed using the weighted average number of common shares outstanding at December 31, 2015 and December 31, 2014, respectively. The weighted average number of common shares outstanding was 29,803,358 at December 31, 2015. Diluted earnings per share reflect the potential dilutive effects of common stock equivalents such as options, warrants and convertible securities. Given the historical and projected future losses of the Company, all potentially dilutive common stock equivalents are considered anti-dilutive.

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The following table outlines outstanding common stock shares and common stock equivalents.

	Years Ended December 31,	
	2015	2014
Common Stock Shares Outstanding	31,220,326	29,202,826
Common Stock Equivalents Outstanding		
Warrants	8,622,486	5,937,386
Stock Options	1,430,000	610,000
Unconverted Class B Shares	137,932	137,932
Total Common Stock Equivalents Outstanding	10,190,418	6,685,318

Income Taxes:

The Company accounts for income taxes in accordance with ASC 740 “Income Taxes” which requires an asset and liability approach for financial accounting and reporting of income taxes. Deferred income taxes reflect the impact of temporary differences between the amount of assets and liabilities for financial reporting purposes and such amounts as measured by tax laws and regulations. Deferred tax assets include tax loss and credit carry forwards and are reduced by a valuation allowance if, based on available evidence, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

Stock-Based Compensation:

The Company applies ASC 718, “Compensation-Stock Compensation” to account for the issuance of options and warrants to employees, key partners, directors, officers and Navitus investors. The standard requires all share-based payments, including employee stock options, warrants and restricted stock, be measured at the fair value of the award and expensed over the requisite service period (generally the vesting period). The fair value of options and warrants granted to employees, directors and officers is estimated at the date of grant using the Black-Scholes option pricing model by using the historical volatility of the Company’s stock price. The calculation also takes into account the common stock fair market value at the grant date, the exercise price, the expected term of the common stock option or warrant, the dividend yield and the risk-free interest rate.

The Company from time to time may issue stock options, warrants and restricted stock to acquire goods or services from third parties. Restricted stock, options or warrants issued to third parties are recorded on the basis of their fair value, which is measured as of the date issued. The options or warrants are valued using the Black-Scholes option pricing model on the basis of the market price of the underlying equity instrument on the “valuation date,” which for options and warrants related to contracts that have substantial disincentives to non-performance, is the date of the contract, and for all other contracts is the vesting date. Expense related to the options and warrants is recognized on a straight-line basis over the shorter of the period over which services are to be received or the vesting period and is included in general and administrative expenses in the accompanying consolidated statements of operations.

The Company recognized stock-based director's compensation expense from warrants and stock awards granted to directors for services of $508,739 and $92,235, for the years ended December 31, 2015 and 2014, respectively.

The Company recognized stock-based incentive compensation expense from stock options granted to officers and employees of the company of $58,373 and $397,939 for the twelve months ended December 31, 2015 and 2014, respectively.

The Company also recognized stock-based general and administrative expense of $169,210 and $81,667 for the twelve months ended December 31, 2015 and 2014, respectively.

Going Concern:

The accompanying consolidated financial statements have been prepared assuming the Company will continue as a going concern, which contemplates the realization of assets and satisfaction of liabilities in the normal course of business. As presented in the consolidated financial statements, the Company has incurred a net loss of $4,905,518 and $4,229,137 during the years ended December 31, 2015 and 2014, respectively. Non-cash expenses and allowances were significant during the years ended December 31, 2015 and December 31, 2014, and the net cash used in operating activities, or negative cash flows from operating activities, were $1,738,853 and $1,137,222, respectively.

The cash proceeds from the sale of the Company's Lightnin Property in June 2014, new contributions to the Aurora partnership by Navitus, and loans from affiliates have allowed the Company to continue operations and invest in new oil and natural gas properties. See Note 4. Management anticipates that operating losses will continue in the near term until new wells are drilled, successfully completed and incremental production increases revenue. On a year to date basis, as of December 31, 2015 the Company has invested $1,058,704 in the drilling of wells and $0 in the acquisition of oil and gas properties.

The Company remains in active discussions with Navitus and others related to longer term financing required for our capital expenditures planned for 2016. Without additional outside investment from the sale of equity securities and/or debt financing, our capital expenditures and overhead expenses must be reduced to a level commensurate with available cash flows.

The accompanying consolidated financial statements are prepared as if the Company will continue as a going concern. The consolidated financial statements do not contain adjustments, including adjustments to recorded assets and liabilities, which might be necessary if the Company were unable to continue as a going concern.

Note 2 - Recent accounting pronouncements

Recently Issued Accounting Standards
In February 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2015-02, "Consolidation (Topic 810): Amendments to the Consolidation Analysis." ASU 2015-02 affects reporting entities that are required to evaluate whether they should consolidate certain legal entities. ASU 2015-02 is effective for periods beginning after December 15, 2015 with early adoption permitted. The Company is currently evaluating the new guidance and has not determined the impact this standard may have on its financial statements.
In May 2014, the FASB issued ASU 2014-09, "Revenue from Contracts with Customers (Topic 606)," which supersedes the revenue recognition requirements in Accounting Standards Codification ("ASC") Topic 605, "Revenue Recognition," and most industry-specific guidance. ASU 2014-09 is based on the principle that revenue is recognized to depict the transfer of 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. ASU 2014-09 also requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts. ASU 2014-09 applies to all contracts with customers except those that are within the scope of other topics in the FASB ASC. The new guidance is effective for annual reporting periods beginning after December 15, 2017 for public companies. Early adoption is not permitted. Entities have the option of using either a full retrospective or modified approach to adopt ASU 2014-09. The Company is currently evaluating the new guidance and has not determined the impact this standard may have on its financial statements or decided upon the method of adoption.
In April 2014, the FASB issued ASU 2014-08, "Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity." ASU 2014-08 prospectively changes the criteria for reporting discontinued operations while enhancing disclosures around disposals of assets whether or not the disposal meets the definition of a discontinued operation. ASU 2014-08 is effective for annual and interim periods beginning after December 31, 2014 with early adoption permitted but only for disposals that have not been reported in financial statements previously issued. The impact of this guidance on the Company's consolidated financial statements will depend on the size and nature of the Company's disposal transactions in the future, which the Company cannot accurately predict. Several of the Company's past dispositions that were treated as discontinued operations may not have been classified as such had the new guidance been in effect.

Note 3 – Oil and natural gas properties

Oil and natural gas properties are comprised of the following:

	December 31, 2015	2014
Proved property	$9,940,660	$8,903,060
Unproved property	1,375,940	1,365,951
Work in process	—	—
Total oil and natural gas properties, at cost	11,316,600	10,269,011
Less: accumulated impairment	(8,283,321)	(7,430,438)
Oil and natural gas properties, net of impairment	3,033,279	2,838,573
Less: accumulated depletion	(2,274,188)	(1,942,380)
Oil and natural gas properties, net	$759,091	$896,193

Depletion, depreciation, and amortization expense for the years ended December 31, 2015 and 2014 was $637,121 and $430,912, respectively. During the years ended December 31, 2015 and 2014, the Company recorded impairment losses of $867,048 and $3,721,042, respectively. As a result of the impairment charges incurred for the year ended December 31, 2014, the Company's unproved property asset base has zero net book value as of December 31, 2015.

Note 4 - Acquisitions and Dispositions

As previously disclosed in the Company's Form 8-K filed on February 4, 2015, Victory entered into a letter of intent ("LOI") relating to a proposed business combination with Lucas Energy, Inc. ("Lucas"). The business combination was contingent on, among other things, the parties completing due diligence, including title due diligence, the mutual negotiation of definitive documents, regulatory approvals and the registration of the securities to be issued to the shareholders of the combined company resulting from the Combination (the “Combined Company”). On February 26, 2015, Victory entered into (a) the Pre-Merger Collaboration Agreement (the “Collaboration Agreement”) by and among Victory, Lucas, Navitus and AEP Assets, LLC ("AEP"), a wholly-owned subsidiary of Aurora; and (b) the Pre-Merger Loan and Funding Agreement (the “Loan Agreement”) between Victory and Lucas. Subsequently the parties entered into Amendment No. 1 to the Pre-Merger Collaboration Agreement on March 3, 2015, which amendments affected thereby are included in the discussion of the Collaboration Agreement below. On March 2, 2015, payments of $195,928 and $317,027 were made by Aurora, on behalf of Victory, to Earthstone Energy/Oak Valley Resources and Penn Virginia, respectively, pursuant to the Pre-Merger Collaboration Agreement for costs related to the two Earthstone Energy/Oak Valley Resources and the five Penn Virginia operated Eagle Ford wells, respectively. The initial draw, and any other amounts borrowed by Lucas under the Loan Agreement were evidenced by a Secured Subordinated Delayed Draw Term Note issued by Lucas in favor of Victory, which was in an initial amount of $250,000 (the “Draw Note”). Borrowings evidenced by the Draw Note accrued interest at 0.5% per annum, with accrued interest payable in one lump sum on maturity. The maturity date of the Draw Note was February 26, 2016. A total of $600,000 was paid to Lucas through May 11, 2015, under the Draw Note. On May 11, 2015, the Company terminated the LOI pursuant to its terms, which permitted either the Company or Lucas to terminate the LOI by written notification to the other party. The Company also notified Lucas pursuant to the Loan Agreement, that it would not extend any further credit to Lucas under the Loan Agreement. Merger and merger termination related direct costs total $1,326,850 and are included in general and administrative expenses for the twelve months ended December 31, 2015.

On June 24, 2015, the Company entered into (1) a Settlement Agreement and Mutual Release (the “Lucas Settlement Agreement”) with Lucas, (2) a Settlement Agreement and Mutual Release (the “Rogers Settlement Agreement”) with Louise H. Rogers, (“Rogers”), and (3) a Compromise Settlement Agreement and Mutual General Release, effective as of June 25, 2015 (the “Earthstone Settlement Agreement”, and, together with the Lucas Settlement Agreement and the Rogers Settlement Agreement, the “Settlement Agreements”) with Earthstone Operating, LLC, Earthstone Energy, Inc., Oak Valley Resources, LLC, Oak Valley Operating LLC and Sabine River Energy, LLC (collectively, “Earthstone”), Lucas, AEP, and Aurora.

Lucas Settlement Agreement

Pursuant to the Lucas Settlement Agreement, the Company and Lucas agreed to terminate any and all obligations between the parties arising under the LOI and the Collaboration Agreement. The Company and Lucas further agreed that the Company would retain ownership and control over five Penn Virginia well-bores previously assigned by Lucas to the Company (the “Penn Virginia Well-Bores”), as well as the obligations to pay the expenses associated with such Penn Virginia Well-Bores effective after August 1, 2014. Under the terms of the Lucas Settlement Agreement, Lucas agreed to assign to the Company all of Lucas’ rights in a certain oil and gas property located in the same field as the Penn Virginia Well-Bores (the “Additional Penn Virginia Property”), including the rights to all revenues from all wells on some properties. Lucas acknowledged the principal amount of $600,000 previously advanced to Lucas by the Company pursuant to the terms of the Loan Agreement and agreed that the Company has no further obligations to advance any additional funds to Lucas pursuant to the terms of the Loan Agreement. Pursuant to the terms of the

Lucas Settlement Agreement, Lucas agreed to issue 1,101,729 shares (44,069 post-split declared by Lucas as of July 15, 2015) shares of its common stock (the "Settlement Shares") to the Company in full consideration of the $600,000 owed under the Loan Agreement. The Settlement Shares and an assignment of the Additional Penn Virginia Property was held in escrow pending the payment by the Company of amounts owed to Rogers under the Rogers Settlement (as described below). The Company has charged the $600,000 to general and administrative expenses as a cost of the merger termination.

Rogers Settlement Agreement

Pursuant to the Rogers Settlement Agreement, the Company and Rogers agreed, among other things, (i) to terminate the contingent promissory note in the principal amount of $250,000 payable to Rogers that was issued by Victory in connection with the entry by Lucas and the Company into the Collaboration Agreement, (ii) that the Company would pay Rogers, on or before July 15,2015, $253,750, and (iii) that Rogers' legal counsel will hold the assignment of the Additional Penn Virginia Property and the Settlement Shares in escrow until such time as the payment of $253,750 is made by the Company to the Rogers.

Amendment to Rogers Settlement Agreement

As of July 16, 2015, the Company entered into an Amendment (the "Rogers Amendment"). Pursuant to the Rogers Amendment, the Company and Rogers agreed that the amount to be paid by the Company to Rogers under the Rogers Settlement Agreement is $258,125, instead of $253,750. The Amendment further specified that if the Company failed to make the payment of $258,125 on or before July 15, 2015, the Company would be in default under the Rogers Settlement Agreement and default interest on the amount due would begin to accrue at a per diem rate of $129.0625. Additionally, the Company acknowledged in the Amendment its obligation to pay Rogers' attorney's fees in the amount of $22,500. As of the date of this Annual Report on Form 10-K, the Company has not made any payments to Rogers pursuant to the Rogers Settlement Agreement.

As described above, Rogers' legal counsel held the assignment to the Company of Lucas Energy, Inc.'s rights additional Penn Virginia Property and the Settlement Shares in escrow pending the Company's payment of all amounts due under the Rogers Settlement Agreement. The Company failed to make the required payment to Roger's by August 27, 2015, and has still not made all the required payments. As a result, the additional Penn Virginia Property was returned to Lucas Energy, Inc. on or about September 3, 2015. The full amount due under the Roger's obligation including accrued interest at December 31, 2015 totals $300,432.

Earthstone Settlement Agreement

Pursuant to the terms of the Earthstone Settlement Agreement, the Company assigned to Earthstone certain oil and gas interests in the wells which were previously transferred to the Company by Lucas in February 2015. The Company and Earthstone also agreed to release each other from any and all claims, demands and causes of action which either party had against the other prior to the effective date of the Earthstone Settlement Agreement, whether known or unknown, except in connection with the breach, enforcement or interpretation of the Earthstone Settlement Agreement. Lucas and Earthstone similarly agreed to release each other from such claims pursuant to the terms of the Earthstone Settlement Agreement. The Company has charged $195,928 related to the Earthstone Settlement Agreement to general and administrative expenses as a cost of the merger termination.

Dispositions

On June 5, 2014, Victory, through its controlling interest and as managing partner in Aurora, sold certain leasehold properties and all of Aurora's related interests in approximately 640 gross and 128 net mineral acres located in Glascock County, Texas (the "Lightnin' Assets") to an unrelated third party (the "Lightnin' Buyer") for approximately $4 million in cash gross to Aurora. The sale was made pursuant to a Purchase and Sale Agreement dated as of April 30, 2014 by and among the working interest owner/sellers, including Aurora, and the Lightnin' Buyer. The effective date for the transaction was April 1, 2014. Aurora held a 20% working and 15% net revenue interest in the Lightnin' Assets which were operated by a third party. Estimated daily net production to Aurora's interest was approximately 36 BOEPD (barrels of oil equivalent per day) at the time of the sale from the 3 producing wells. The Company recognized a gain on the sale of the Lightnin' Assets of $2,160,099 in its consolidated statement of operations for the year ended December 31, 2014.

Acquisitions

On June 30, 2014, Aurora completed the First Closing of a purchase of a 10% working and 7.5% net revenue interest in the proved and unproved Permian Basin Fairway Operations from Target Energy Limited, which we refer to as TELA for an initial payment of $2,491,888 in cash, subject to customary purchase price adjustments (the "Fairway Acquisition"), pursuant to the terms and conditions of the Purchase and Sale Agreement dated June 30, 2014 between

Aurora and TELA (the "Fairway PSA"). On the First Closing, TELA assigned certain assets in its Permian Basin Fairway Operation (the “First Closing Assets”) to Aurora. The second closing (the “Second Closing”) was planned to follow the completion of curative title work and was expected in August 2014. On July 31, 2014, the Company made an additional payment related to its Fairway Property acquisition. The payment of $558,246 to the seller of the Fairway properties was a purchase price adjustment made in accordance with the purchase and sale agreement related thereto. On the Second Closing, TELA was to assign the remainder of its assets in its Permian Basin Fairway Operations to Aurora. The Effective Date for the transfer of all assets was May 1, 2014.

The acquisition of the First Closing Assets included seven producing wells and four wells completed and awaiting production start-up.
On September 23, 2014, the Company mutually agreed to the termination of the Fairway PSA. Pursuant to the termination of the Fairway PSA, the Second Closing did not occur as the result of certain title impairment issues that were uncovered during the due diligence process and that were not remedied to the satisfaction of the Company and TELA. No penalties or payments were due as a result of the termination of the Fairway PSA. See footnote 12 for further discussion.

In the fourth quarter of 2014, the Company made a final determination as to the purchase price resulting in a final purchase price of $3,214,872. The amount of the total purchase price allocated to undeveloped oil and gas properties was reduced by these adjustments. The adjusted purchase price was allocated as follows:

	Fairway Purchase Price Allocation
Fair Value of Assets Acquired - Tangible and Intangible Well costs	$ 2,240,530
Fair Value of Assets Acquired - Proved Producing Leasehold Costs	197,654
Fair Value of Assets Acquired Unproved Leasehold Costs	776,688
Net Asset Fair Value Final	$ 3,214,872

The acquisitions qualified as a business combination under ASC 805. The valuation to determine the fair values were principally based on the discounted cash flows of the producing and undeveloped properties, including projected drilling and equipment costs, recoverable reserves, production streams, future prices and operating costs, and risk-adjusted discount rates reflective of the market at the time of acquisition. These measurements of fair value are considered Level 3 measurements because of the significance of unobservable inputs.

Note 5 - Gain from Settlement Agreement

As previously reported in the Company's Form 8-K report filed November 27, 2015, effective as of November 21, 2015, Aurora entered into a Settlement Agreement and Release (the "Settlement Agreement and Release") to settle the outstanding litigation between Aurora and Trilogy in the case styled Trilogy Operating, Inc. v. Aurora Energy Partners, which was pending in Howard County, Texas (the "Litigation"). Pursuant to the Settlement Agreement and Release, Aurora agreed to assign any and all of its interests in four specified wells located in Glasscock and Howard Counties, those being Wagga Wagga #2, Homar #1, Ballarat '185' #1 and BOA North #5 (collectively, the "Obligation Wells"). The Company has not historically included any production or reserve information in its financial or operational reporting in any of its prior filings for these Obligation Wells.

The Company recorded these costs, billed to it by the operator, in 2014 to oil and gas property acquisitions. In accordance with the Company's impairment policy these costs were charged to impairment expense in the Company's Consolidated Statement of Operations for the year ending December 31, 2014. Due to continuing litigation the related joint interest payable balance to the operator remained outstanding until the settlement on November 21, 2015. This settlement included the reversal or cancellation of all related outstanding joint interest billings payable to the operator. The Company therefore recorded a $637,248 non-cash gain on the settlement of this matter in the Company's Consolidated Statement of Operations for the year ending December 31, 2015.

Note 6– Liability for Unauthorized Preferred Stock Issued

During the year ended December 31, 2006, the Company authorized the issuance of 10,000,000 shares of Preferred Stock, convertible at the shareholder's option to common stock at the rate of 100 shares of common stock for every share of preferred stock. During the year ended December 31, 2006, the Company issued 715,517 shares of preferred stock for cash of $246,950.

The Company subsequently issued additional preferred stock and had several preferred shareholders convert their shares into common stock during the years ended December 31, 2009, 2008, and 2007.

The Company’s legal counsel determined that the preferred shares had not been duly authorized by the State of Nevada. Since the Company had issued and received consideration for the preferred stock, notwithstanding that the stock was not legally authorized, the Company has presented the preferred stock as a liability in the consolidated balance sheets. The Company has offered to settle the debt with the remaining holders of the unauthorized preferred stock by honoring the terms of conversion of two shares of preferred stock into 100 shares of common stock. The Company intends to cancel the preferred stock once all remaining preferred stockholders have converted.

There were 68,966 and 68,966 shares of unconverted preferred stock outstanding at December 31, 2015 and 2014, respectively. The Company needs approximately 138,000 common shares in order to settle the outstanding debt as stated below.

The remaining liability for the unconverted preferred stock is based on the original cash tendered and consisted of the following as of:

	December 31,	
	2015	2014
Liability for unauthorized preferred stock	$9,283	$9,283

Note 7 - Revolving Credit Agreement

On February 20, 2014, Aurora, as borrower, entered a credit agreement (the "Credit Agreement") with Texas Capital Bank (“the Lender”). Guarantors on the Credit Agreement are Victory and Navitus, the two partners of Aurora. Pursuant to the Credit Agreement, the Lender agreed to extend credit to Aurora in the form of (a) one or more revolving credit loans (each such loan, a “Loan”) and (b) the issuance of standby letters of credit, of up to an aggregate principal amount at any one time not to exceed the lesser of (i) $25,000,000 or (ii) the borrowing base in effect from time to time (the “Commitment”). The initial borrowing base on February 20, 2014 was set at $1,450,000. The borrowing base is determined by the Lender, in its sole discretion, based on customary lending practices, review of the oil and natural gas properties included in the borrowing base, financial review of Aurora, the Company and Navitus and such other factors as may be deemed relevant by the Lender. The borrowing base is re-determined (i) on or about June 30 of each year based on the previous December 31 reserve report prepared by an independent reserve engineer, and (ii) on or about August 31 of each year based on the previous June 30 reserve report prepared by Aurora’s internal reserve engineers or an independent reserve engineer and certified by an officer of Aurora. The Credit Agreement will mature on February 20, 2017. Amounts borrowed under the Credit Agreement will bear interest at rates equal to the lesser of (i) the maximum rate of interest which may be charged or received by the Lender in accordance with applicable Texas law and (ii) the interest rate per annum publicly announced from time to time by the Lender as the prime rate in effect at its principal office plus the applicable margin. The applicable margin is, (i) with respect to Loans, one percent (1.00%) per annum, (ii) with respect to letter of credit fees, two percent (2.00%) per annum and (iii) with respect to commitment fees, one-half of one percent (0.50%) per annum. Loans made under the Credit Agreement are secured by (i) a first priority lien in the oil and gas properties of Aurora, the Company and Navitus, and (ii) a first priority security interest in substantially all of the assets of Aurora and its subsidiaries, if any, as well as in 100% of the partnership interests in Aurora held by the Company and Navitus. Loans made under the Credit Agreement to Aurora are fully guaranteed by the Company and Navitus.

The Credit Agreement contains various affirmative and negative covenants. These covenants, among other things, limit additional indebtedness, additional liens and transactions with affiliates. Among the covenants contained in the Credit Agreement are financial covenants that Aurora will maintain a minimum EBITDAX to Cash Interest Ratio of 3.5 to 1.0 and a minimum Current Ratio of not less than 1.0 to 1.0. The Current Ratio is defined under the covenants to include, as a current asset, the revolving credit availability. At December 31, 2015, Aurora's Current Ratio was 0.10 to 1 and it was therefore not in compliance with the aforementioned Current Ratio covenant requiring a ratio of current assets to current liabilities of not less than 1 to 1. As of December 31, 2015, the $680,000 outstanding balance of the Credit Agreement was classified as a current liability in accordance with GAAP.

On April 13, 2015, the Company received the annual Borrowing Base Adjustment called for under the terms of the Credit Agreement, which called for a decrease in the borrowing base of $300,000 payable by May 13, 2015, and an increase in the monthly reduction amount to $10,000 commencing as of June 1, 2015. Additionally, the Lender notified Aurora that, based on the Lender’s redetermination of Aurora’s borrowing base, the monthly reduction amount under the Credit Agreement was increased, commencing on June 1, 2015, from $0 to $10,000. Pursuant to this increase in the monthly reduction amount, Aurora’s borrowing base will be automatically reduced by $10,000 on the first day of each calendar month beginning on June 2015 until the Lender’s next periodic borrowing base redetermination.

On August 21, 2015, the Company executed a Forbearance Agreement whereby the Lender would forbear all existing events of default which includes all payments under the previously mentioned Borrowing Base Deficiency payments not yet paid under the April 13, 2015 Redetermination Date notification, as well as the late interest payments for June, July and August 2015, violations of Aurora financial covenants for the three months ended March 31, 2015, and June 30, 2015, and default notice for the late filing of March 31, 2015 financial reports. On August 26, 2015, the Company paid the Lender $76,081 to cover a portion of the deficiency payment, as well as a Forbearance document fee and Lender's legal expenses, as required by the Forbearance Agreement, and the aforementioned Forbearance Agreement went into effect for the $260,000 remaining borrowing base deficiency payment. On August 31, 2015, the Forbearance Agreement terminated pursuant to its terms. The Company did not make the above payment and has been in continuous contact with its lender regarding its plan of payment of the $260,000 as well as the remaining credit facility balance. The Company made a $50,000 principle payment to the lender on October 14, 2015 as part of that plan.

As of December 31,2015, the Company was out of compliance with the Current Ratio, and out of compliance with the EBITDAX to Cash Interest Ratio due to its reduced revenue streams from price and production declines and continued high general and administrative expenses for the quarter ended December 31, 2015. Therefore, the Company is in technical default of the Credit Agreement and related agreements. The Company's lender has not yet been advised by the lender of an additional actions the lender plans to take.

Amortization of debt financing costs on this debt was $40,823 and $34,586 for the twelve months ended December 31, 2015 and December 31, 2014, respectively. Interest expense was $40,053 and 30,595 for the twelve months ended December 31, 2015, and December 31, 2014, respectively.

Note 8 – Income Taxes

There was no provision for (benefit of) income taxes for the years ended December 31, 2015 and 2014, after the application of ASC 740 "Income Taxes."

The Internal Revenue Code of 1986, as amended, imposes substantial restrictions on the utilization of net operating losses in the event of an "ownership change" of a corporation. Accordingly, a company's ability to use net operating losses may be limited as prescribed under Internal Revenue Code Section 382 ("IRC Section 382"). Events which may cause limitations in the amount of the net operating losses that the Company may use in any one year include, but are not limited to, a cumulative ownership change of more than 50% over a three-year period. There have been transactions that have changed the Company's ownership structure since inception that may have resulted in one or more ownership changes as defined by the IRC section 382. The Company's stock issuance arising from convertible debt in 2012 has resulted in a limitation of net operating loss carry forward for the Company of $13,807,335 over a 20-year period.

At December 31, 2015, the Company had available Federal operating loss carry forwards to reduce future taxable income. Additional Federal net operating loss carry forward of $2,734,175 for 2015 would make available approximately $20,490,123 as of December 31, 2015. The Federal net operating loss carry forwards begin to expire in 2028. Capital loss carryovers may only be used to offset capital gains.

Given the Company's history of net operating losses, management has determined that it is more likely than not the Company will not be able to realize the tax benefit of the net operating loss carry forwards. ASC 740 requires that a valuation allowance be established when it is more likely than not that all or a portion of deferred tax assets will not be realized.

Accordingly, the Company has recorded a full valuation allowance against its net deferred tax assets at December 31, 2015 and 2014, respectively. Upon the attainment of taxable income by the Company, management will assess the likelihood of realizing the deferred tax benefit associated with the use of the net operating loss carry forwards and will recognize a deferred tax asset at that time.

Significant components of the Company's deferred income tax assets are as follows:

	December 31, 2015	December 31, 2014
Net operating loss carry forward	$6,966,642	$6,037,022
Depreciation and accretion	7,222	3,209
Equity based expenses	1,920,230	1,912,720
Impairment losses on oil and gas properties	1,559,951	1,265,154
Deferred taxes	10,449,482	9,218,105
Valuation allowance	(10,449,482)	(9,218,105)
Net Deferred Income Tax Assets	$—	$—

Reconciliation of the effective income tax rate to the U.S. statutory rate is as follows:

	12/31/2015	12/31/2014
Net operating loss	34 %	34 %
Meals and entertainment	0.03 %	0.15 %
Debt discount accretion	0.04 %	0.10 %
Net operating loss reduction due to IRC 382	—	— %
Change in valuation allowance	33.92 %	33.75 %
Effective income tax rate	— %	— %

ASC 740 provides guidance which addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the consolidated financial statements. Under the current accounting guidelines, the Company may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the consolidated financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. As of December 31, 2015 and 2014 the Company does not have a liability for unrecognized tax benefits.

The Company has elected to include interest and penalties related to uncertain tax positions as a component of income tax expense. To date, no penalties or interest has been accrued.

Tax years 2011 forward are open and subject to examination by the Federal taxing authority. The Company is not currently under examination and it has not been notified of a pending examination.

Note 9 – Stockholders' Equity

Long-Term Incentive Plan

On February 24, 2014, the Board of Directors (the "Board") of the Victory Energy Corporation (the "Company") approved and adopted the Victory Energy Corporation 2014 Long Term Incentive Plan (the "LTIP") for the employees, directors and consultants of the Company and its affiliates. The LTIP provides for the grant of all or any of the following components: (1) stock options, (2) restricted stock, (3) other stock-based awards, (4) performance awards and (5) dividends and dividend equivalents. Subject to adjustment in accordance with the LTIP, the maximum aggregate number of shares of the common stock of the Company, par value $0.001 per share (the "Common Stock") that may be issued with respect to awards under the LTIP is fifteen percent (15%) of the outstanding shares of Common Stock at the end of the preceding calendar quarter, of which the maximum number of such shares that may be issued as incentive stock options, as defined in Section 422(b) of the Internal Revenue Code of 1986 is two million (2,000,000) shares of Common Stock. Common Stock withheld to satisfy exercise prices or tax withholding obligations will be available for delivery pursuant to other awards. The LTIP will be administered by the Board, until such time as a compensation committee of the Board is established (the "Compensation Committee"), at which time the LTIP will be administered by the Compensation Committee. The total number of shares of common stock initially available for issuance under the LTIP was 4,591,174. As of December 31, 2015, 3,367,500 shares of unrestricted common stock and 970,000 options were issued under the LTIP. The maximum contractual term is five years. As of December 31, 2015, 253,674 shares of common stock are available for issuance under the LTIP.

Stock Based Compensation

The Company estimates the fair value of employee stock options and warrants granted using the Black-Scholes Option Pricing Model. Key assumptions used to estimate the fair value of warrants and stock options include the exercise price of the award, the fair value of the Company's common stock on the date of grant, the expected warrant or option term, the risk free interest rate at the date of grant, the expected volatility and the expected annual dividend yield on the Company's common stock.

During the year ended December 31, 2015, the Company granted 2,017,500 stock awards to directors, officers, and employees at fair value of the stock on the date of issuance, of $508,739.

Note 10 – Warrants for Stock

At December 31, 2015 and 2014 warrants outstanding for common stock of the Company were as follows:

	Number of Shares Underlying Warrants	Weighted Average Exercise Price
Balance at January 1, 2015	5,937,386	$0.66
Granted	2,917,000	0.29
Exercised	—	—
Canceled	(231,900)	2.18
Balance at December 31, 2015	8,622,486	$0.48

	Number of Shares Underlying Warrants	Weighted Average Exercise Price
Balance at January 1, 2014	4,931,386	$0.76
Granted	1,140,000	0.30
Exercised	—	—
Canceled	(134,000)	1.10
Balance at December 31, 2014	5,937,386	$0.66

During the year ended December 31, 2015, the Company granted 2,917,000 warrants for $2,917,000 in capital contributions through Navitus Partners, LLC valued with the Black Scholes pricing model.

The following table summarizes information about underlying outstanding warrants for common stock of the Company outstanding and exercisable as of December 31, 2015:

	Warrants Outstanding			Warrants Exercisable	
Range of Exercise Prices	Number of Shares Underlying Warrants	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (in years)	Number of Shares Underlying Warrants	Weighted Average Exercise Price
$12.50 – $17.50	104,845	$12.50	6.79	104,845	$12.50
$0.13 – $2.50	8,517,641	$0.30	2.88	8,517,641	$0.30
	8,622,486			8,622,486	

The following table summarizes information about underlying outstanding warrants for common stock of the Company outstanding and exercisable as of December 31, 2014:

	Warrants Outstanding			Warrants Exercisable	
Range of Exercise Prices	Number of Shares Underlying Warrants	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (in years)	Number of Shares Underlying Warrants	Weighted Average Exercise Price
$12.50 – $17.50	125,245	$13.03	6.62	125,245	$13.03

$0.25 – $2.50	5,812,141	$0.39	3.17	5,812,141	$0.31
	5,937,386			5,937,386	

These common stock purchase warrants do not trade in an active securities market, and as such, we estimate the fair value of these warrants using the Black-Scholes Option Pricing Model using the following assumptions:

	2015	2014
Risk free interest rates	1.25% – 1.72%	0.77% – 1.73%
Expected life	5 years	5 years
Estimated volatility	422.9% – 667.5%	629.8% – 788.7%
Dividend yield	— %	— %

Expected volatility is based primarily on historical volatility. Historical volatility was computed using daily pricing observations for recent periods that correspond to the expected term of the warrants. We believe this method produces an estimate that is representative of our expectations of future volatility over the expected term of these warrants. We currently have no reason to believe future volatility over the expected term of these warrants is likely to differ materially from historical volatility. The expected term is based on the remaining term of the warrants. The risk-free interest rate is based on U.S. Treasury securities.

At December 31, 2015 and 2014 the aggregate intrinsic value of the warrants outstanding and exercisable was $50,580 and $5,295, respectively. The intrinsic value of a warrant is the amount by which the market value of the underlying warrant exercise price exceeds the market price of the stock at December 31 of each year.

Note 11 – Stock Options

The following table summarizes stock option activity in the Company’s stock-based compensation plans for the year ended December 31, 2015. All options issued were non-qualified stock options.

	Number of Options	Weighted Average Exercise Price	Aggregate Intrinsic Value (1)	Number of Options Exercisable	Weighted Average Fair Value At Date of Grant
Outstanding at December 31, 2013	150,000	$0.64	$—	150,000	$0.64
Granted at Fair Value	400,000	$0.33	$—	91,667	$0.33
Exercised	—	$—	$—	—	$—
Forfeited	(90,000)	$0.35	$—	(67,500)	$0.35
Outstanding at December 31, 2014	460,000	$0.43	$—	174,167	$0.59
Granted at Fair Value	1,000,000	$0.27	$—	483,333	$0.27
Exercised	—	$—	$—	—	$—
Cancelled	(30,000)	$0.50	$—	(30,000)	$0.50
Outstanding at December 31, 2015	1,430,000	$0.31	$—	627,500	$0.34

(1) The intrinsic value of a stock option is the amount by which the market value of the underlying stock exceeds the exercise price of the option at December 31, 2015. If the exercise price exceeds the market value, there is no intrinsic value.

During the year ended December 31, 2015, the Company granted 600,000 employee stock options at fair value on the date of issuance, totaling $160,080.

During the year ended December 31, 2015, the Company granted 400,000 stock options for consulting services measurable at fair value on the date of issuance at $107,960.

The fair value of the stock option grants are amortized over the respective vesting period using the straight-line method and assuming no forfeitures and cancellations.

Compensation expense related to stock options included in general and administrative expense in the accompanying consolidated statements of operations for the years ended December 31, 2015 and December 31, 2014, was $166,333, and $81,667, respectively.

Stock options are granted at the fair market value of the Company’s common stock on the date of grant. Options granted to officers and other employees vest immediately or over 36 months as provided in the option agreements at the date of grant.

The fair value of each option granted in 2015 and 2014 was estimated using the Black-Scholes Option Pricing Model. The following assumptions were used to compute the weighted average fair value of options granted during the periods presented.

	2015		2014	
Expected term of option	3 years		3 years	
Risk free interest rates	1.52	%	0.8	%
Estimated volatility	606.3		629.8 - 785.7	
Dividend yield	—	%	—	%

The following table summarizes information about stock options outstanding at December 31, 2015:

Range of Exercise Prices	Number of Options	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price	Aggregate Intrinsic Value (1)	Number Exercisable	Weighted Average Exercise Price of Exercisable Options	Aggregate Intrinsic Value (1)
$0.27 - $1.00	1,430,000	2.13	$0.31	$—	750,833	$0.34	$—

(1) The intrinsic value of a stock option is the amount by which the market value of the underlying stock exceeds the exercise price of the option at December 31, 2013. If the exercise price exceeds the market value, there is no intrinsic value.

The following table summarizes information about options outstanding at December 31, 2014:

Range of Exercise Prices	Number of Options	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price	Aggregate Intrinsic Value (1)	Number Exercisable	Weighted Average Exercise Price of Exercisable Options	Aggregate Intrinsic Value
$0.27 - 1.00	460,000	2.28	$0.43	$—	241,667	$0.59	$—

A summary of the Company’s non-vested stock options at December 31, 2015 and December 31, 2014 and changes during the years are presented below.

Non-Vested Stock Options	Options		Weighted Average Grant Date Fair Value
Non-Vested at December 31, 2014	285,833		$0.33
Granted	1,000,000		$0.27
Vested	(576,667	)	$0.34
Forfeited	(30,000	)	$—
Non-Vested at December 31, 2015	679,166		$0.28

Note 12 – Commitments and Contingencies

Leases

Rent expense for the years ended December 31, 2015 and 2014 was $29,250 and $28,500, respectively. Future annual minimum payments under non-cancellable operating leases are $0 and $0 for the years ending December 31, 2015 and 2016, respectively.

Partnership Distributions

Under terms of the Second Amended Partnership Agreement of Aurora, Navitus earns a net profits interest respective to its 50% partnership interest. In addition, Navitus is entitled to a respective proportion of proceeds from the sale of Aurora assets. Any distributions of the net profits interest or asset sale proceeds to partners are at the discretion of Victory, as managing partner, together with 100% of the partnership interests. The accumulated net deficits of Navitus, along with historical contributions, net of paid distributions, are reported as non-controlling interests in the equity section of the consolidated balance sheets.

Under the terms of Aurora's Seconded Amended Partnership Agreement, Navitus Partners, LLC, the fourth partner of the Navitus Energy Group, admitted under the Navitus Private Placement Memorandum (the "Navitus PPM"), earns a preferred return distribution of 10% based upon capital contributions to Aurora used by Victory to acquire or develop oil and gas prospects or related enterprises on behalf of Aurora. The preferred return distribution is in addition to and does not reduce any net profits or asset sale proceeds interests distributions.

The table below summarizes the net profit distributions, proceeds of asset sales and preferred return distributions earned by Navitus Energy Group during the years ended December 31, 2015 and 2014, respectively.

Navitus Energy Group Distribution Earned	Year Ended December 31,	
	2015	2014
Aurora Net Profits Interests	$78,963	$41,895
Proceeds from the Sale of Aurora Assets	—	1,824,398
Preferred Distributions Due to Navitus Partners, LLC	656,256	401,081
Total Distributions Earned By Navitus Energy Group	$735,219	$2,267,374

The table below summarizes the net profit distributions, proceeds of asset sales and preferred return distributions paid to Navitus Energy Group during the years ended December 31, 2015 and 2014, respectively.

Payments Made to Navitus Energy Group	Year Ended December 31,	
	2015	2014
Distributions of Aurora Net Profits	$—	$86,517
Proceeds from the Sale of Aurora Assets	—	219,029
Preferred Distributions Due to Navitus Partners, LLC	—	341,876
Total Distributions Paid By Navitus Energy Group	$—	$647,422

Navitus Partners, LLC, a partner in Navitus, also receives warrants for Victory's common stock, allocated as 50,000 warrants for every Unit purchased under the Navitus PPM (equivalent of 1 warrant for every $1.00 invested), exercisable under the terms of Aurora's Second Amended Partnership Agreement and the Navitus PPM. Since August 23, 2012, $7,332,900 of capital contributions have resulted in issuance of 7,332,900 common stock warrants (1,089,900 in 2012, 2,186,000 in 2013, 1,140,000 in 2014, and 2,917,000 in 2015).

Litigation

Cause No. 08-04-07047-CV; Oz Gas Corporation v. Remuda Operating Company, et al. v. Victory Energy Corporation.; In the 112th District Court of Crockett County, Texas.
Plaintiff Oz Gas Corporation ("Oz") filed a lawsuit in April 2008 against various parties for bad faith trespass, among other claims, regarding the drilling of two wells on lands that Oz claims title to. On November 18, 2009, Victory Energy Corporation intervened in the lawsuit to protect its 50% interest in one of the named wells in the lawsuit (that being the 155-2 well located on the Adams Baggett Ranch in Crockett County, Texas).

This case was mediated, with no settlement reached. It went to trial February 8-9, 2012. The Court found in favor of Oz and rendered verdict against Victory and the other Defendants, jointly and severally. Victory appealed this case to the 8th Court of Appeals in El Paso, Texas where the Court of Appeals affirmed the verdict of the District Court and Victory filed a Motion for

Rehearing, which was denied. Victory filed a Petition for Review in the Supreme Court of Texas on December 15, 2014 which was denied. Victory filed a Motion for Rehearing with the Supreme Court which was denied.

Oz filed Interrogatories and Request for Production in Aid of Judgment which have been answered by Victory.

A Settlement and Forbearance Agreement was entered into on March 22, 2016 between the parties wherein no further post-judgment discovery or collection efforts will be made by Oz, for $140,000 net of a $14,000 payment received by the Oz receiver (see next following Cause No. C-1-CV-16-001610), with monthly payments of $7,500 commencing April, 15, 2016. This amount is included in Accrued Liabilities as of December 31, 2015.

Cause No. C-1-CV-16-001610; Oz Gas Corporation v. Victory Energy Corporation; In the County Court at Law No. 1 of Travis County, Texas.

Plaintiff Oz Gas Corporation ("Oz") filed an Application for Turnover Relief in Travis County, Texas on February 19, 2016. This order was granted and Thomas L. Kolker was appointed as Receiver to assist in the collection of non-exempt assets. Victory itself has not been placed into Receivership. Victory filed its Motion to Vacate the Turnover that was heard and denied by the trial court. Oz has since filed an Amended Application for Turnover Relief and Appointment of a Receiver to be heard March 10, 2016. Victory filed its Notice of Appeal March 4, 2016. Victory and Oz are now in the process of attempting to resolve the case outside of the judicial process.

A Settlement and Forbearance Agreement was entered into on March 22, 2016 between the parties wherein no further post-judgment discovery or collection efforts will be made by Oz, for $140,000 net of a $14,000 payment received by the Oz receiver, with monthly payments of $7,500 commencing April 15, 2016, and an Agreed Motion Vacating Turnover Order with a Proposed Order Vacating Appointment of Receiver has been filed with the court.

Cause No. CV-47,230; James Capital Energy, LLC and Victory Energy Corporation v. Jim Dial, et al.; In the 142nd District Court of Midland County, Texas.

This is a lawsuit filed on or about January 19, 2010 by James Capital Energy, LLC and Victory Energy Corporation against numerous parties for fraud, fraudulent inducement, negligent misrepresentation, breach of contract, breach of fiduciary duty, trespass, conversion and a few other related causes of action. This lawsuit stems from an investment Victory entered into for the purchase of six wells on the Adams Baggett Ranch with the right of first refusal on option acreage.

On December 9, 2010, Victory was granted an interlocutory Default Judgment against Defendants Jim Dial, 1st Texas Natural Gas Company, Inc., Universal Energy Resources, Inc., Grifco International, Inc., and Precision Drilling & Exploration, Inc. The total judgment amounted to approximately $17,183,987.

Victory has added a few more parties to this lawsuit. Discovery is ongoing in this case and no trial date has been set at this time.

Victory believes they will be victorious against all the remaining Defendants in this case.

On October 20, 2011 Defendant Remuda filed a Motion to Consolidate and a Counterclaim against Victory. Remuda is seeking to consolidate this case with two other cases wherein Remuda is the named Defendant. An objection to this motion was filed and the cases have not been consolidated. Additionally, we do not believe that the counterclaim made by Remuda has any legal merit.

Cause No. 10-09-07213; Perry Howell, et al. v. Charles Gary Garlitz, et al.; In the 112th District Court of Crockett County, Texas.

The above referenced lawsuit was filed on or about September 6, 2010. This lawsuit alleges that Cambrian Management, Ltd. and Victory were trespassers on their land, and that they, along with other Defendants, drilled a well (115 #8) on land belonging to Plaintiffs. Plaintiffs claim trespass and unjust enrichment by certain Defendants because of the drilling of the 115 #8 well.

Discovery is ongoing in this case and no trial date has been set. Victory believes that the claims made by Plaintiffs have no merit and that they will prevail at trial. Mediation began on August 8, 2013 and was adjourned to a later date which has not been set yet.

Cause No. D-1-GN-13-000044; Aurora Energy Partners and Victory Energy Corporation v. Crooked Oaks, LLC; In the 261st District Court of Travis County, Texas.

Victory Energy Corporation sued Crooked Oaks, LLC a/k/a Crooked Oak, LLC for breach of a purchase and sale agreement dated May 7, 2012 in which Victory sold certain assets to Crooked Oaks, LLC for $400,000 of which only $200,000 has been paid as

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of December 31, 2014. The lawsuit seeks to recover the remaining balance owed of $200,000 from Crooked Oaks, LLC in addition to attorney's fees and all costs of court. Crooked Oaks, LLC has asserted a counterclaim for rescission of the underlying contract.
Victory and Crooked Oaks attended a mediation on February 10, 2016 where it was determined that Crooked Oaks was insolvent and since that date the case has been dismissed with prejudice.
Cause No. 50198; Trilogy Operating, Inc. v. Aurora Energy Partners; In the 118th Judicial District Court of Howard County, Texas.
This lawsuit was filed on January 9, 2015. This lawsuit alleges causes of action for declaratory judgment, breach of contract, and suit to quiet title regarding the drilling and completion of four wells. On or about February 12, 2015, the parties met at an informal settlement conference. At the adjournment of the meeting, Trilogy was to provide Aurora with a detailed accounting before proceeding forward. The accounting provided by Trilogy was not helpful and Aurora has asked for an audit under the terms set out in the Joint Operating Agreement. Discovery is ongoing in this case and no trial date has been set at this time. Victory does not believe that all of Plaintiff's claims have merit, and thus an audit is needed before proceeding any further.
The parties entered into a Settlement Agreement and Release on November 20, 2015 and an Agreed Order to Dismiss with Prejudice was granted on November 24, 2015.
Cause No. 50,916; Trilogy Operating Inc. v. Aurora Energy Partners; In the 118th Judicial District Court of Howard County, Texas.
This lawsuit was filed on January 6, 2016. This lawsuit alleges causes of action for a suit on a sworn account, breach of contract and a suit to foreclose on liens regarding the drilling and completion of seven wells. Aurora filed an answer on January 29, 2016. Trilogy filed a Motion for Partial Summary Judgment on March 23, 2016 to which Aurora will respond. Discovery is ongoing in this case and no trial date has been set at this time.
The potential liability of Aurora is the $123,354 (the costs associated with the wells and recorded in the Company's Joint Interest Billing - Accounts Payable) and attorney's fees.
Cause No. 2015-05280; TELA Garwood Limited, LP. v. Aurora Energy Partners, Victory Energy Corporation, Kenneth Hill, David McCall, Robert Miranda, Robert Grenley, Ronald Zamber, and Patrick Barry; In the 164th District Court of Harris County, Texas.
This lawsuit was filed on January 30, 2015 and supplemented on March 4, 2015. This lawsuit alleges breach of contract regarding a Purchase and Sale Agreement that TELA Garwood Limited, LP and Aurora Energy Partners entered into on June 30, 2014. A first closing was held on June 30, 2014 and a purchase price adjustment payment was made on July 31, 2014. Between these two dates Aurora paid TELA approximately $3,050,134. A second closing was to take place in September, however several title defect were found to exist. The title defects could not be cured and a purchase price reduction could not be agreed upon by the parties in relation to the title defects, therefore, the second closing was terminated by TELA. Aurora and Victory have filed an answer in this case. Both parties have filed opposing motions for summary judgment and are awaiting a hearing date from the court. If this case is not resolved by summary judgment or by settlement, then a trial date has been set for August 2016.

Note 13 – Related Party Transactions

During the year ended December 31, 2015 we incurred a total of $411,059 in legal fees with The McCall Firm. David McCall, our general counsel and a director, is a partner in The McCall Firm. The fees are attributable to litigation involving the Company's oil and natural gas operations in Texas. As of December 31, 2015, the Company owed The McCall Firm approximately $371,826 for these professional services.

During the year ended December 31, 2015, a member of management made a $29,553 temporary advance to the Company, a member of the board of directors made a $15,000 temporary advance to the Company, and temporary capital advances totaling $388,800 had been made by Navitus Energy Group Partnership. All the above amounts are recorded in Accrued Liabilities - related parties.

As of July 1, 2014, Ralph Kehle was appointed as a Board of Director for the Company. Mr. Kehle was also the Chairman of the Board for TELA (USA), Inc. Aurora and TELA entered into a letter of intent on May 8, 2014 and followed by entering into a Purchase and Sale Agreement dated June 30, 2014 for the Fairway Acquisition. Mr. Kehle received 95,000 shares of common stock, valued at $32,200, for his board services as of December 31, 2014. Mr. Kehle resigned from our Board of Directors in December 2014.

Note 14 - Subsequent Events

During the period of January 1, 2016 through and March 31, 2016, additional contributions of $402,000 were received, resulting in the issuance of an additional 402,000 common stock warrants for the purchase of shares of common stock of the Company.

On January 6, 2016, Cause No. 50916, Trilogy Operating, Inc. v. Aurora Energy Partners, was filed in the 118th District Court of Howard County, Texas. This lawsuit alleges causes of action for a suit on a sworn account, breach of contract and a suit to foreclose on liens regarding the drilling and completion of seven wells. Aurora filed an answer on January 29, 2016. Discovery is ongoing in this case and no trial date has been set at this time.

A Settlement and Forbearance Agreement was entered into on March 22, 2016 between the parties wherein no further post-judgment discovery or collection efforts will be made by Oz, for $154,000 of which $14,000 has been settled and $140,000 is remaining to be paid with monthly payments of $7,500 commencing April 15, 2016. This amount is included in Accrued Liabilities as of December 31, 2015.

Supplementary Financial Information on Oil and Natural Gas Exploration, Development and Production Activities (Unaudited)

The following disclosures provide unaudited information required by ASC 932, “Extractive Activities – Oil and Gas” on oil and natural gas producing activities. These disclosures include non-controlling interests in Aurora which is managed and owned 50% by Victory.

Results of operations from oil and natural gas producing activities (Successful Efforts Method)

The Company’s oil and natural gas properties are located within the United States. The Company currently has no operations in foreign jurisdictions. Results of operations from oil and natural gas producing activities are summarized below for the years ended December 31:

	Years Ended December 31,	
	2015	2014
Revenues	$650,648	$695,318
Costs incurred:		
Exploration and dry hole costs	2,513	56,351
Lease operating costs and production taxes	192,504	225,074
Impairment of oil and natural gas reserves	867,048	3,721,042
Depletion, depreciation and accretion	637,121	430,912
Totals, costs incurred	1,699,186	4,433,379
Pre-tax (loss) from producing activities	(1,048,538)	(3,738,061)
Results (loss) from of oil and natural gas producing activities (excluding overhead, income taxes, and interest costs)	$(1,048,538)	$(3,738,061)

Costs incurred in oil and natural gas property acquisition, exploration and development activities are summarized below for the years ended December 31:

	Years Ended December 31, 2015	2014
Property acquisition and developmental costs:		
Development	$1,058,704	$841,270
Property Acquisition	—	3,214,872
Undrilled Leaseholds	—	22,577
Asset retirement obligations	2,506	3,721
Totals costs incurred	$1,061,210	$4,082,440

Oil and natural gas reserves

Proved reserves are estimated quantities of oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserves that can reasonably be expected to be recovered through existing wells with existing equipment and operating methods.

Proved oil and natural gas reserve quantities at December 31, 2015 and 2014 and the related discounted future net cash flows are based on estimates prepared by independent petroleum engineers. Such estimates have been prepared in accordance with guidelines established by the Securities and Exchange Commission.

Standardized measure of discounted future net cash flows relating to proven oil and gas reserves (SMOG)

The following information has been prepared in accordance with the Financial Accounting Standards Board pronouncements and the regulations of the Securities and Exchange Commission, which require the standardized measure of discounted future cash flows based on sales prices, costs and statutory interest rates. The standardized measure of oil and gas producing activities is the present value of estimated future cash inflow from proved oil and natural gas reserves, less future development, abandonment, production and income tax expenses, discounted to reflect timing of future cash flows.

The Company’s proved oil and natural gas reserves for the years ended December 31, 2015 and December 31, 2014 are shown below:

	Years Ended December 31, 2015	2014
Volumes		
Natural gas:	(Mcfs)	
Proved developed and undeveloped reserves (mcf):		
Beginning of year	600,000	723,190
Purchase (sale) of natural gas properties in place	—	(46,770)
Discoveries and extensions	26,680	—
Revisions	(410,362)	(30,843)
Production	(37,568)	(45,577)
Proved reserves, at end of year (a)	178,750	600,000

	Years Ended December 31,	
	2015	2014
Oil:	(Bbls)	
Proved developed and undeveloped reserves:		
Beginning of year	20,700	49,020
Purchase (sale) of oil producing properties in place	—	(26,290)
Discoveries and extensions	30,720	1,175
Revisions	2,112	3,700
Production	(12,152)	(6,905)
Proved reserves, at end of year (a)	41,380	20,700

(a) Includes 89,375 Mcf and 20,690 bbl and 300,000 Mcf and 10,350 bbl for the twelve months ended December 31, 2015 and 2014, respectively of proved reserves attributable to a consolidated subsidiary in which there is a 50% non-controlling interest.

	Years Ended December 31,	
Values	2015	2014
Future cash inflows	$2,345,940	$4,920,190
Future costs:		
Production	(964,520)	(2,144,600)
Development	(87,650)	(87,650)
Future cash flows	1,293,770	2,687,940
10% annual discount for estimated timing of cash flow	(421,640)	(1,223,370)
Standardized measure of discounted cash flow (a)	$872,130	$1,464,570

(a) Includes $436,065 and $732,285 for the twelve months ended December 31, 2015 and 2014, respectively, of discounted cash flows attributable to a consolidated subsidiary in which there is a 50% non-controlling interest.

Using the SEC adjusted guidelines in place for 2016, the gas and oil prices for this analysis were set at the average price received on the “first-day-of-the-month” for 2015, for appropriate differentials. The “benchmark” prices are $50.28 per barrel and $2.58 per Mcf. The average quarterly price received for natural gas for 2015 ranged from $2.85 /Mcf to $3.33 /Mcf . The average quarterly price received oil for 2015 ranged from $39.41/bbl to $46.54/bbl.

Future income taxes are based on year-end statutory rates, adjusted for tax basis of oil and natural gas properties and availability of applicable tax assets, such as net operating losses. A discount factor of 10% was used to reflect the timing of future net cash flows.

The standardized measure of discounted future net cash flows is not intended to represent the replacement cost or fair market value of the Company’s oil and natural gas properties. An estimate of fair value may also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs, and may require a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

Changes in standardized measure

Included within standardized measure are reserves purchased in place. The purchase of reserves in place includes undeveloped reserves which were acquired at minimal value that have been estimated by independent reserve engineers to be recoverable through existing wells utilizing equipment and operating methods available to the Company and that are expected to be developed in the near term based on an approved plan of development contingent on available capital.

Changes in the standardized measure of future net cash flows relating to proved oil and natural gas reserves for the years ended December 31 is summarized below:

	For the years ended December 31, 2015	2014
Increase (decrease)		
Sale of gas and oil, net of operating expenses	$(458,144)	$(470,244)
Discoveries, extensions and improved recovery, net of future production and development costs	—	—
Accretion of discount	146,500	242,210
Net increase (decrease)	$(311,644)	$(228,034)
Standardized measure of discounted future cash flows:		
Beginning of the year	$1,464,570	$2,422,100
Before Income Taxes	$872,130	$1,464,570
Income Taxes	(287,358)	(500,586)
End of the year (a)	$584,772	$963,984

(a) Includes $292,386 and $481,992 for the twelve months ended December 31, 2015 and 2014, respectively of future net cash flows attributable to a consolidated subsidiary in which there is a 50% non-controlling interest.