TRANS ENERGY INC
Form 10-K
May 11, 2015
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the Fiscal Year Ended December 31, 2014

¨ **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 0-23530

TRANS ENERGY, INC.

(Exact name of registrant as specified in its charter)

Nevada	**93-0997412**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

210 Second Street, P.O. Box 393, St. Marys, West Virginia 26170

(Address of principal executive offices)

Registrant s telephone number, including area code: (304) 684-7053

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

Securities registered pursuant to Section 12(g) of the Act: Common Stock, $.001 par value

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

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 x

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 past 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

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 (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant s knowledge, in the definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨

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

Large accelerated filer ¨	Accelerated filer ¨
Non-accelerated filer ¨ (Do not check if smaller reporting company)	Smaller reporting company x

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant s most recently completed second fiscal quarter (June 30, 2014) was $12,995,608 (based on a price of $4.00 per share).

The number of shares outstanding of each of the issuer s classes of common stock, as of May 11, 2015, was 14,776,467 shares

Documents incorporated by reference: None

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PART I

Item 1 Business

History

Trans Energy, Inc. (we, our, us or the Company), a Nevada corporation formed in 1993, is an independent energy company engaged in the acquisition, exploration, development and production of oil and natural gas, and, to a lesser extent, the marketing and transportation of natural gas. As of December 31, 2014, we own working interests in 38 wells that have been completed in the Marcellus Shale formation, including 26 horizontal proved developed producing wells, 1 vertical proved developed producing well, 8 horizontal proved developed nonproducing wells, and 3 vertical proved developed nonproducing wells. In addition, we also own overriding royalty interests in approximately 300 shallow oil and gas wells in West Virginia, of which 127 are currently active. We also own and operate an aggregate of 19 miles of 6-inch and 4-inch gas transmission lines located within West Virginia in Ritchie and Tyler counties. We also have 40,146 gross acres (15,456 net) under lease in West Virginia primarily in the counties of Wetzel, Marshall, and Marion.

Our principal executive offices are located at 210 Second Street, P.O. Box 393, St. Marys, West Virginia 26170, and our telephone number is (304) 684-7053.

Our business strategy is to economically increase reserves, production and the sale of oil, natural gas, and natural gas liquids from existing and acquired properties in the Appalachian Basin in order to maximize shareholders return over the long term. Our strategic location in West Virginia enables us to actively pursue the acquisition and development of producing properties in that area that will enhance our revenue base without proportional increases in overhead costs.

We have been an oil and gas developer for more than twenty years, but began a more aggressive focus on development and growth in early 2006. We began an effort to leverage the Company s acreage and reserves to fund development, and since early 2006 have drilled more than 34 horizontal and 4 vertical wells and significantly increased production and reserves. During late 2007, we redirected our focus from shallow drilling to drilling exclusively in the Marcellus Shale.

Current Business Activities

We operate our oil and natural gas properties and transport and market natural gas through our transmission systems in West Virginia. Although management desires to acquire additional oil and natural gas properties and to become more involved in exploration and development, this can only be accomplished if we can secure future funding. Management intends to continue to develop and increase the production from the oil and natural gas properties that it currently owns.

Recent Events

On December 24, 2014, our wholly owned subsidiary, American Shale Development, Inc. (American Shale), closed a transaction pursuant to a Purchase and Sale Agreement (the PSA) executed as of December 24, 2014 with Wellbore Capital, LLC, a Delaware limited liability company (Wellbore). Pursuant to the PSA, American Shale granted to Wellbore a 2% overriding royalty interest in 12 wells and approximately 7,450 gross lease acres (the Oil and Gas Properties) located in Wetzel and Marion Counties, West Virginia (collectively, the ORRI) leaving American Shale with approximately a 30% NRI. Under the PSA, the purchase price for the ORRI was $11.0 million, of which the Company received approximately $10.7 million in cash at closing. The PSA provides Wellbore the right to sell its interests in the ORRI to a third party acquiror in the event that American Shale sells all of their interests in the oil and gas properties to such acquiror. If such sale occurs prior to December 31, 2017, Wellbore alternatively has the right to require American Shale to repurchase the ORRI for a 20% return on its investment in the ORRI.

On October 1, 2014, Trans Energy, Inc. pleaded guilty to three misdemeanor charges related to Unauthorized Discharge into a Water of the United States in violation of the Clean Water Act (CWA) (collectively, the CWA Matter). In connection with this plea, the Company agreed to pay a $600,000 fine and was placed on probation for a period of two years. This fine was consistent with the amount the Company anticipated as disclosed in the Form 8-K filed September 3, 2014, that described the civil settlement reached with the Environmental Protection Agency (EPA). On August 29, 2014, the EPA previously filed an information in the federal district court in the Northern District of West Virginia alleging that Trans Energy had committed misdemeanor violations of the CWA.

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On August 25, 2014, we entered into a civil Consent Decree with the EPA with respect to the Clean Water Act matter and related issues that were discovered based upon an internal audit that we conducted. The Consent Decree requires us to pay a $3,000,000 civil penalty in two installments. The Consent Decree requires us to perform certain restoration activities at the affected pond, well pad and access road sites over a period of three construction seasons. The EPA has estimated that the restoration will cost as much as $13 million, but we intend to perform the work in a manner that will cause our costs to be significantly below this estimate. The Consent Decree also requires us to put in place and maintain an environmental compliance program.

On May 21, 2014 (*Funding Date*), American Shale entered into a credit agreement (the *Morgan Stanley Credit Agreement*) with several banks and other financial institutions (the *Lenders*) and Morgan Stanley Capital Group Inc. as the administrative agent (*Agent*). Trans Energy is a guarantor of the Morgan Stanley Credit Agreement as is Prima Oil Company, Inc. (*Prima*), another of our wholly owned subsidiaries. The Morgan Stanley Credit Agreement provides that the Lenders will lend American Shale up to $200 million, including an initial draw of $102.5 million, a contingent committed amount of $47.5 million and an uncommitted amount of $50 million (the *Loans*). The initial draw under the facility was used primarily to repay all of the outstanding debt under the Chambers Credit Agreement with Chambers Energy Management, LP (*Chambers*), as well as to fund certain fees and expenses incurred in connection with the Morgan Stanley Credit Agreement.

On the Funding Date, American Shale also entered into a purchase and sale agreement (the *Republic PSA*) with its joint venture partner, Republic Energy Ventures (*Republic*). Under the Republic PSA, for $15 million, American Shale sold (i) an undivided interest across all of its undeveloped leasehold amounting to approximately 2,239 net acres, (ii) an over-riding royalty interest of 1.5% in all of its leasehold in Wetzel County, West Virginia, and (iii) an over-riding royalty interest of 1.0% in six (6) wells that are currently being drilled in Marshall County, West Virginia. The consideration was paid in the form of a credit against expenses incurred by Republic on behalf of American Shale. American Shale retained the option to repurchase the undivided interest across all of its undeveloped leasehold, plus the over-riding royalty interest in its Wetzel County leasehold, for $15 million if (i) such payment is made within six (6) months of the Funding Date, or (ii) a purchase and sale agreement that would allow for such repayment by American Shale is signed within such period and the transaction contemplated therein is closed prior to December 31, 2014. As of September 30, 2014, the Company had recognized a deferred gain on sale of assets in the current liabilities section of the Condensed Consolidated Balance Sheet in the amount of $6,959,816 because the Company had the option of repurchasing the undivided interest across all of its undeveloped leasehold, plus the overriding royalty interest in its Wetzel County leasehold by December 31, 2014. This deferred gain on sale of assets was recognized as gain as of December 31, 2014, because the option to repurchase had expired.

At September 30, 2014, we believed that the deferred gain resulted in our current ratio not exceeding 1-to-1 as of September 30, 2014, as required by the covenants of the Morgan Stanley Credit Agreement. Consequently, since failing to meet that ratio would constitute a default under that agreement, all outstanding obligations under the Morgan Stanley Credit Agreement as of September 30, 2014 were reflected on the balance sheet as current maturities of long-term debt. However, subsequent to December 31, 2014, we determined that we had not included certain items in the calculation of our current ratio that we were entitled to include. Upon inclusion of these items, we determined that our current ratio did exceed 1-to-1 as of September 30, 2014 and that we were not then and are not as of December 31, 2014, in violation of any of the covenants under the Morgan Stanley Credit Agreement. Consequently, obligations payable under the Morgan Stanley Credit Agreement due after December 31, 2015 are shown as long-term debt in our financial statements as of December 31, 2014.

As part of the Republic PSA, Republic also agreed to amend the Amended Joint Development Agreement (ADJA) with American Shale. Under the revised AJDA, Republic agreed to fund all costs associated with new leasehold acquisitions subsequent to April 1, 2014. American Shale has the right to buy a 25% interest in any such leasehold at

Republic s cost, plus 12% interest, in the event that Republic sells its interest in the leasehold or permits to drill a well on the leasehold. In the event that American Shale repays Republic under the terms of the Republic PSA, American Shale will have the option to fund a 50% portion of any future leasehold expenditures, upon providing satisfactory evidence of its ability to continue such funding on a go-forward basis.

Drilling Operations

Republic Partners Joint Venture

We drilled 14 horizontal wells in 2014 and retained a 50% working interest in five of the wells, approximately a 40% working interest in five of the wells, and approximately a 36% working interest in the remaining four wells. In 2013, we drilled seven horizontal wells and retained a 50% working interest in six of the wells and approximately a 44% working interest in the remaining well. In 2012, we drilled five horizontal wells and retained a 50% working interest in three of the wells and approximately a 36% working interest in the remaining two wells.

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Gastar Farm Out

Of the six horizontal wells drilled in 2011, four were drilled through a farm out with Gastar Exploration USA, Inc. (Gastar), whereby Gastar would purchase a working interest in the wellbores. We retained a 5% working interest in the wellbores and Gastar retained a 45% working interest. Once Gastar receives 100% of their investment; then our working interest will increase to 12.5% and Gastar s working interest will be reduced to 37.5%. Republic retained 50% working interest in these wells as permitted by the terms of the joint venture.

The following table summarizes the status of the wells drilled under the joint venture with Republic, which includes the farm out to Gastar.

Name	Net WI	Spud Date	Completion Date	Status
Woodruff 1H	.41	January 2014	April 2014	Producing
Woodruff 2H	.41	February 2014	April 2014	Producing
Blackshere 200H	.36	March 2014	June 2014	Shut In
Blackshere 201H	.36	March 2014	June 2014	Shut In
Anderson 8H	.35	May 2014	August 2014	Producing
Anderson 9H	.36	May 2014	August 2014	Producing
Jones 3H	.44	May 2014	Est. 2015	Est. 2015
Shaver 1H	.50	July 2014	November 2014	Shut In
Shaver 2H	.50	July 2014	November 2014	Shut In
Sivert 1H	.44	July 2014	September 2014	Shut In
Sivert 2H	.44	July 2014	September 2014	Shut In
Wright 2H	.50	September 2014	Est. 2015	Est. 2015
Wright 1H	.50	October 2014	Est. 2015	Est. 2015
Michael 1H	.50	November 2014	Est. 2015	Est. 2015
Freeland 1H	.50	March 2013	July 2013	Producing
Goshorn 3H	.50	April 2013	June 2013	Producing
Goshorn 4H	.50	May 2013	June 2013	Producing
Freeland 2H	.50	May 2013	July 2013	Producing
Jones 2H	.44	June 2013	Est. 2015	Est. 2015
Beaty 2H	.50	July 2013	November 2013	Producing
Beaty 1H	.50	August 2013	November 2013	Producing
Anderson 5H	.36	January 2012	May 2012	Producing
Anderson 7H	.36	January 2012	May 2012	Producing
Doman 1H	.50	April 2012	October 2012	Producing
Doman 2H	.50	May 2012	October 2012	Producing
Martinez 1H	.43	June 2012	April 2013	Producing
Whipkey 3H	.05	May 2011	June 2011	Producing
Lucey 2H	.05	August 2011	October 2011	Shut In
Goshorn 1H	.05	October 2011	January 2012	Producing
Goshorn 2H	.05	November 2011	March 2012	Producing
Dewhurst 110H	.38	December 2011	May 2012	Producing
Dewhurst 111H	.38	December 2011	April 2012	Producing
Stout 2H	.49	August 2010	January 2011	Producing
Groves 1H	.50	September 2010	March 2011	Producing

Keaton 1H	.49	November 2010	March 2011	Producing
Lucy 1H	.50	December 2010	May 2011	Shut In
Whipkey 1H	.47	November 2009	May 2010	Producing
Whipkey 2H	.50	November 2009	April 2010	Producing
Dewhurst 73V	.50	June 2008	July 2008	Shut In
Hart 28H	.50	October 2008	April 2009	Producing
Dewhurst 50V	.50	October 2007	November 2007	Shut In
Hart 20V	.50	November 2007	March 2008	Producing
Blackshere 101V	1.00	November 2007	December 2007	Shut In

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Marketing

We operate exclusively in the oil and gas industry. Natural gas production from wells owned by us is generally sold to various intrastate and interstate pipeline companies and natural gas marketing companies. Sales are generally made under short-term delivery contracts at market prices. These prices fluctuate with natural gas contracts as posted in national publications and on the New York Mercantile Exchange.

The majority of our natural gas is sold to SEI Energy, LLC.

Natural gas delivered through Trans Energy s pipeline network is sold primarily to Dominion Gas, a local utility company, on an on-going basis at a variable price per month per Mcf, or to Sancho Oil and Gas Corporation (Sancho), a company controlled by a director of Trans Energy, at the industrial facilities near Sistersville, West Virginia. Approximately 98% of our natural gas is sold to Dominion and the remaining 2% is sold to Sancho. Under our contract with Sancho, we have the right to sell natural gas subject to the terms and conditions of a contract that Sancho originally entered into with Dominion Gas in 1988. This agreement is a flexible volume supply agreement whereby we receive the full price that Sancho charges the end user, less a $0.05 per Mcf marketing fee paid to Sancho. During 2014 and 2013, Sancho retained their marketing fee and remitted a net amount to us.

We sell our oil production to third party purchasers under agreements at posted field prices. These third parties purchase the oil at the various locations where the oil is produced and haul it via truck. We currently sell to one oil purchaser, BD Oil Gathering Corporation.

We sell our NGLs to Williams Ohio Valley Midstream, LLC. Sales are generally made under short-term delivery contracts at market prices. These prices fluctuate with natural gas contracts as posted in national publications and on the New York Mercantile Exchange.

Competition

We are in direct competition with numerous oil and natural gas companies, drilling and income programs and partnerships exploring various areas of the Appalachian Basin. Many competitors are large, well-known oil and gas and/or energy companies. Although no single entity dominates the industry, many of our competitors possess greater financial and personnel resources, sometimes enabling them to identify and acquire more economically desirable energy producing properties and drilling prospects. We are and have the traditional competitive strengths of a regional operator, including long established contacts and in-depth knowledge of the local geography. There is also the possibility that future energy-related legislation and regulations may impact competitive conditions. Management believes that a viable market place exists for regional producers of oil and natural gas and operators of regional natural gas transmission systems.

Oil and Gas Regulation

The availability of a ready market for oil and natural gas production depends upon numerous factors beyond the Company s control. These factors may include, among other things, federal, state and local regulation of oil and natural gas production and transportation, including regulations governing environmental quality, pollution control and limits on allowable rates of production by a well or proration unit, the amount of oil and natural gas available for sale, the availability of adequate pipeline and other transportation and processing facilities, and the marketing of competitive fuels.

Most states, and some counties and municipalities, in which the Company operates also regulate one or more of the following:

- The location of wells;
- The method of drilling, completing and operating wells;
- The surface use and restoration of properties upon which wells are drilled;
- The venting or flaring of natural gas;
- Produced water and waste disposal;
- The plugging and abandoning of wells; and
- Notice to surface owners and other third parties.

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State and federal regulations are generally intended to prevent waste of oil and natural gas, protect rights to produce oil and natural gas between owners in a common reservoir, control the amount of oil and natural gas produced by assigning allowable rates of production and control contamination of the environment. Pipelines and natural gas plants operated by other companies that provide midstream services to the Company are also subject to the jurisdiction of various federal, state and local authorities, which can affect our operations. State laws also regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties and impose bonding requirements in order to drill and operate wells.

Many states impose a production, ad valorem or severance tax with respect to the production and sale of oil and gas within their jurisdiction. States do not generally regulate wellhead prices or engage in other, similar direct economic regulation, but there can be no assurance they will not do so in the future.

The Company s sales of natural gas are affected by the availability, terms and costs of transportation both in the gathering systems that transport the natural gas from the wellhead to the interstate pipelines and in the interstate pipelines themselves. The rates, terms and conditions applicable to the interstate transportation of natural gas by pipelines are regulated by the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act, as well as under Section 311 of the Natural Gas Policy Act. Since 1985, the FERC has issued and implemented regulations intended to increase competition within the natural gas industry by making natural gas transportation more accessible to natural gas buyers and sellers on an open-access, non-discriminatory basis.

The pipelines used to gather and transport natural gas being constructed by the Company and its partners are subject to regulation by the U.S. Department of Transportation (DOT) under the Natural Gas Pipeline Safety Act of 1968, as amended (NGPSA), the Pipeline Safety Act of 1992, as reauthorized and amended (Pipeline Safety Act), and the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. The DOT Pipeline and Hazardous Materials Safety Administration (PHMSA) has established a risk-based approach to determine which gathering pipelines are subject to regulation and what safety standards regulated gathering pipelines must meet. In August 2011, the PHMSA issued an Advance Notice of Proposed Rulemaking regarding pipeline safety, including questions regarding the modification of regulations applicable to gathering lines in rural areas.

Surface Damage Acts

Several states have enacted surface damage statutes. These laws are designed to compensate for damages caused by oil and gas development operations. Most surface damage statutes contain entry and negotiation requirements to facilitate contact between the operator and surface owners. Most also contain binding requirements for payments by the operator in connection with development operations. Costs and delays associated with surface damage statutes could impair operational effectiveness and increase development costs.

Environmental Regulations

General. The Company s exploration, drilling and production activities from wells and oil and natural gas facilities, including the operation and construction of pipelines, plants and other facilities for transporting, processing, treating or storing oil, natural gas and other products are subject to stringent federal, state and local laws and regulations relating to environmental quality, including those relating to oil spills and pollution control. The EPA has identified environmental compliance by the energy extraction sector as one of its enforcement initiatives for 2014-2016 and as a general matter, the oil and gas exploration and production industry has been the subject of increasing scrutiny and regulation by environmental authorities. Although such laws and regulations can increase the cost of planning, designing, installing and operating such facilities, it is anticipated that, absent the occurrence of an extraordinary event, compliance with them will not have a material effect upon the Company s operations, capital expenditures, earnings or competitive position.

Solid and Hazardous Waste. The Company has previously owned or leased and currently owns or leases, numerous properties that have been used for the exploration and production of oil and natural gas for many years. Although the Company utilized standard operating and disposal practices, hydrocarbons or other solid wastes may have been disposed of or released on or under such properties or on or under locations where such wastes have been taken for disposal. In addition, many of these properties are or have been operated by third parties over whom the Company has no control, nor has ever had control as to such entities treatment of hydrocarbons or other wastes or the manner in which such substances may have been disposed of or released. State and federal laws applicable to oil and natural gas wastes and properties have gradually become stricter over time. Under current and evolving law, it is possible the Company could be required to remediate property, including ground water, impacted by operations of the Company or by such third party operators, or impacted by previously disposed wastes including performing remedial plugging operations to prevent future, or mitigate existing contamination.

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Although oil and gas wastes generally are exempt from regulation as hazardous wastes (Hazardous Wastes) under the federal Resource Conservation and Recovery Act (RCRA) and some comparable state statutes, it is possible some wastes the Company generates presently or in the future may be subject to regulation under RCRA and state analogs. The Environmental Protection Agency (EPA) and various state agencies have limited the disposal options for certain wastes, including Hazardous Wastes and there is no guarantee that the EPA or the states will not adopt more stringent requirements in the future. Furthermore, certain wastes generated by the Company s oil and natural gas operations that are currently exempt from designation as Hazardous Wastes may in the future be designated as Hazardous Wastes under RCRA or other applicable statutes, and therefore be subject to more rigorous and costly operating and disposal requirements.

Hydraulic Fracturing. Many of the Company s exploration and production operations depend on the use of hydraulic fracturing to enhance production from oil and gas wells. Hydraulic fracturing activities are typically regulated by state oil and gas commissions but not at the federal level, as the federal Safe Drinking Water Act (SDWA) expressly excludes regulation of these fracturing activities (except where diesel is a component of the fracturing fluid). Congress has periodically considered legislation to amend the federal Safe Drinking Water Act to remove the exemption from permitting and regulation provided to injection for hydraulic fracturing (except where diesel is a component of the fracturing fluid) and to require the disclosure and reporting of the chemicals used in hydraulic fracturing. This type of federal legislation, if adopted, could lead to additional regulation and permitting requirements that could result in operational delays making it more difficult to perform hydraulic fracturing and increasing our costs of compliance and operating costs.

In addition, the EPA has recently issued draft guidance regarding federal regulatory authority over hydraulic fracturing using diesel under the Safe Drinking Water Act s Underground Injection Control Program. Further, in March 2010, the EPA announced that it would conduct a wide-ranging study on the effects of hydraulic fracturing on drinking water resources. The EPA released a progress report in December 2012 and final results were expected in 2014 but have not yet been released. This study and the EPA s enforcement initiative for the energy extraction sector could result in additional regulatory scrutiny that could make it difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

In addition, some states have adopted, and other states are considering adopting, regulations that require disclosure of the chemicals in the fluids used in hydraulic fracturing. Additionally, some states, localities and local regulatory districts have adopted or have considered adopting regulations to limit, and in some case impose a moratorium on hydraulic fracturing or other restrictions on drilling and completion operations, including requirements regarding casing and cementing of wells; testing of nearby water wells; restrictions on access to, and usage of, water; and restrictions on the type of chemical additives that may be used in hydraulic fracturing operations. Although none of the Company s properties are in jurisdictions where the limits have been imposed, it is possible the jurisdictions where the Company s properties are located may adopt such limits or other limits on hydraulic fracturing in the future. Further, the EPA has announced an initiative under The Toxic Substances Control Act to develop regulations governing the disclosure and evaluation of hydraulic fracturing chemicals and is working on regulations for wastewater generated by hydraulic fracturing.

Superfund. Under the federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also known as the Superfund law, liability, generally, is joint and several for costs of investigation and remediation and for natural resource damages, without regard to fault or the legality of the original conduct, on certain classes of persons with respect to the release into the environment of substances designated under CERCLA as hazardous substances (Hazardous Substances). These classes of persons, or so-called potentially responsible parties (PRP), include current and certain past owners and operators of a facility where there has been a release or threat of release of a Hazardous Substance and persons who disposed of or arranged for the disposal of the Hazardous Substances found at such a facility. CERCLA also authorizes the EPA and, in some cases, third parties to take actions in response to releases and threats of releases to protect the public health or the environment and to seek to recover from the PRP the costs of such action. Although CERCLA generally exempts petroleum from the definition of Hazardous Substance, in the course of its operations, the Company has generated and will generate wastes that fall within CERCLA s definition of Hazardous Substances. The Company may also be an owner or operator of facilities on which Hazardous Substances have been released. The Company may be responsible under CERCLA for all or part of the costs to clean up facilities at which such substances have been released and for natural resource damages, as a past or present owner or operator or as an arranger. Many states have comparable laws imposing liability on similar classes of persons for releases, including for releases of materials that may not be included in CERCLA s definition of Hazardous Substances. To its knowledge, the Company has not been named a PRP under CERCLA (or any comparable state law) nor have any prior owners or operators of its properties been named as PRPs related to their ownership or operation of such property.

Oil Pollution Act. The Oil Pollution Act of 1990 (OPA), which amends and augments oil spill provisions of the Clean Water Act (CWA), imposes certain duties and liabilities on certain responsible parties related to the prevention of oil spills and damages resulting from such spills in or threatening United States waters or adjoining shorelines. A liable responsible party includes the owner or operator of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge or, in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. OPA assigns liability, which generally is joint and several, without regard to fault, to each liable party for oil removal costs and for a variety of public and private damages. Although defenses and limitations exist to the liability imposed by OPA, they are limited. In the event of an oil discharge or substantial threat of discharge, the Company could be liable for costs and damages.

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Air Emissions. The Company s operations are subject to local, state and federal regulations for the control of emissions from sources of air pollution. Federal and state laws generally require new and modified sources of air pollutants to obtain permits prior to commencing construction, which may require, among other things, stringent, technical controls. Other federal and state laws designed to control hazardous (toxic) air pollutants might require installation of additional controls. Administrative agencies can bring actions for failure to comply with air pollution regulations or permits and generally enforce compliance through administrative, civil or criminal enforcement actions, which may result in fines, injunctive relief and imprisonment.

On April 17, 2012, the EPA issued final rules to subject oil and gas operations to regulation under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS) programs under the Clean Air Act (CAA), and to impose new and amended requirements under both programs. The EPA rules include NSPS standards for completions of hydraulically fractured natural gas wells. Before January 1, 2015, these standards require owners/operators of oil and gas wells to reduce emissions of volatile organic compounds (VOCs) during completions by either flaring using a completion combustion device or capturing any natural gas not delivered into gathering pipelines in a process commonly referred to as a green completion. Beginning January 1, 2015, operators must capture the natural gas and make it available for use or sale. In addition, the rules establish new requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, natural gas processing plants, and certain other equipment. These rules may require changes to our operations, including possible installation of new equipment to control emissions. We continuously evaluate the effect of new rules on our business.

Clean Water Act. The Clean Water Act (CWA) and analogous state laws restrict the discharge of pollutants, including produced waters and other oil and natural gas wastes, into waters of the United States, a term broadly defined to include, among other things, certain wetlands. Under the Clean Water Act, permits must be obtained for the discharge of pollutants into waters of the United States. The CWA provides for administrative, civil and criminal penalties for unauthorized discharges, both routine and accidental, of pollutants and of oil and hazardous substances. It imposes substantial potential liability for the costs of removal or remediation associated with discharges of oil or hazardous substances. State laws governing discharges to water also provide varying civil, criminal and administrative penalties and impose liabilities in the case of a discharge of petroleum or its derivatives, or other hazardous substances, into state waters. In addition, the EPA has promulgated regulations that may require permits to discharge storm water runoff, including discharges associated with construction activities. The CWA also prohibits the discharge of fill materials to regulated waters including wetlands without a permit.

Endangered Species Act. The Endangered Species Act (ESA) was established to protect endangered and threatened species. Pursuant to that act, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The Company conducts operations on oil and natural gas leases that have species, such as raptors, that are listed and species, such as sage grouse, that could be listed as threatened or endangered under the ESA. The U.S. Fish and Wildlife Service must also designate the species critical habitat and suitable habitat as part of the effort to ensure survival of the species. A critical habitat or suitable habitat designation or the mere presence of threatened or endangered species could result in further material restrictions to land use and may materially delay or prohibit land access for oil and natural gas development. If the Company were to have portions of its leases designated as critical or suitable habitat, it may adversely impact the value of the affected leases.

Climate Change Legislation. More stringent laws and regulations relating to climate change and greenhouse gases (GHGs), including methane and carbon dioxide, may be adopted and could cause the Company to incur material expenses in complying with them. In the absence of comprehensive federal legislation on GHG emission control, the EPA attempted to require the permitting of GHG emissions; although the Supreme Court struck down the permitting requirements, it upheld the EPA s authority to control GHG emissions when a permit is required due to emissions of other pollutants. The EPA has established GHG reporting requirements for sources in the petroleum and natural gas industry, requiring those sources to monitor, maintain records on, and annually report their GHG emissions. Although the rule does not limit the amount of GHGs that can be emitted, it could require us to incur significant costs to monitor, keep records of, and report GHG emissions associated with our operations. The EPA recently announced its intention to take measures to require or encourage reductions in methane emissions, including from oil and natural gas operations. Those measures include the development of NSPS regulations in 2016 for reducing methane from new and modified oil and gas production sources and natural gas processing and transmission sources.

In addition to possible federal regulation, a number of states, individually and regionally, also are considering or have implemented GHG regulatory programs. These or other potential federal and state initiatives may result in so-called cap-and-trade programs, under which overall GHG emissions are limited and GHG emissions are then allocated and sold, and possibly other regulatory requirements, that could result in the Company incurring material expenses to comply, e.g., by being required to purchase or to surrender allowances for GHGs resulting from its operations. These regulatory initiatives also could adversely affect the marketability of the oil and natural gas the Company produces.

The Company believes that it is in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on the Company.

Employees

As of the end of our fiscal year on December 31, 2014, we employed seventeen full-time employees, consisting of five executives and managers, nine marketing, lease acquisition and clerical persons, and three field operations employees.

None of our employees are members of any union, nor have they entered into any collective bargaining agreements. We believe that our relationship with our employees is good. With the successful implementation of our business plan, we may seek additional employees in the next year to handle anticipated potential growth.

Industry Segments

We are presently engaged in the principal business of the exploration, development and production of oil and natural gas. We are also involved in pipeline transportation and marketing of oil and natural gas.

Item 1A Risk Factors

You should carefully consider the risks and uncertainties described below and other information in this report. If any of the following risks or uncertainties actually occur, our business, financial condition and operating results, would likely suffer. Additional risks and uncertainties, including those that are not yet identified or that we currently believe are immaterial, may also adversely affect our business, financial condition or operating results.

We have a history of losses and may realize future losses

Our revenues increased approximately 48% during the fiscal year ended December 31, 2014, primarily due to an increase in production volumes. However, we may not achieve, or subsequently maintain profitability if our revenues do not increase in the future. We have experienced operating losses, negative cash flow from operations and net losses in most quarterly and annual periods for the past several years. As of December 31, 2014, our net operating loss carry forward was approximately $63.6 million and our accumulated deficit was approximately $63.3 million. We expect to continue to incur significant costs in connection with exploration and development of new and existing properties.

Accordingly, we will need to generate significant revenues to achieve, attain, and eventually sustain profitability. If revenues do not increase, we may be unable to attain or sustain profitability on a quarterly or annual basis. Any of these factors could cause the price of our stock to decline.

Our business requires significant capital expenditures and we may not be able to obtain needed capital or financing on satisfactory terms or at all.

Future capital requirements after 2014 may require additional capital borrowing or selling equity or other securities that would dilute the ownership percentage of our existing stockholders. Such securities could also have rights, preferences or privileges senior to those of our common stock. Similarly, if we raise additional capital by issuing debt securities, those securities may contain covenants that restrict us in terms of how we operate our business, which could also affect the value of our common stock. If we borrow more money, we will have to pay interest and may also have to agree to restrictions that limit operating flexibility. We may not be able to obtain funds needed to finance operations at all, or may be able to obtain funds only on very unattractive terms. Management may also explore other alternatives such as a joint venture with other oil and gas companies. There can be no assurances, however, that we will conclude any such transaction.

The Morgan Stanley Credit Agreement contains restrictive covenants that may limit our ability to respond to changes in market conditions or pursue business opportunities.

The Morgan Stanley Credit Agreement restrictive covenants that limit our ability to, among other things:

- incur additional indebtedness or liens;
- enter into fundamental changes;
- dispose of property;

- pay dividends or distributions;
- make capital expenditures or investments;
- enter into transactions with affiliates;
- enter into certain hedging transactions;
- create or acquire subsidiaries;
- drill without providing title opinions;
- amend certain documents; and
- appoint non-approved officers or directors.

In addition, we will be required to use substantial portions of our future cash flow to repay principal and interest on our indebtedness. The Morgan Stanley Credit Agreement also includes certain customary affirmative covenants such as minimum hedging requirements, delivery of financial information, operation and maintenance of properties, and maintenance of books and records. Financial covenants include a maximum leverage ratio (latest twelve months EBITDA to net debt) and minimum current ratio (consolidated current assets to consolidated current liabilities). American Shale is also required to apply toward approved capital expenditures a minimum of 50% of the proceeds of any equity issuance that occurs subsequent to the first anniversary of the Funding Date. The requirement that we comply with these provisions may materially adversely affect our ability to react to changes in market conditions, take advantage of business opportunities we believe to be desirable, obtain future financing, fund needed capital expenditures or withstand a continuing or future downturn in our business. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowings or arrange new financing, an event of default would occur under our Morgan Stanley Credit Agreement.

Our borrowings under Morgan Stanley Credit Agreement expose us to interest rate risk.

Our earnings are exposed to interest rate risk associated with borrowings under the Morgan Stanley Credit Agreement, which bear interest at a rate that is based on the LIBOR plus 9%. If interest rates increase, so will our interest costs, which may have a material adverse effect on our results of operations and financial condition.

A decrease in oil and natural gas prices may adversely affect our results of operations and financial condition.

Energy commodity prices have been historically highly volatile, and such high levels of volatility are expected to continue in the future. We cannot accurately predict the market prices that we will receive for the sale of our natural gas, condensate, or oil production.

Oil and natural gas prices are subject to a variety of additional factors beyond our control, which include, but are not limited to: changes in the supply of and demand for oil and natural gas; market uncertainty; weather conditions in the United States; the condition of the United States economy; the actions of the Organization of Petroleum Exporting Countries; governmental regulation; political stability in the Middle East and elsewhere; the foreign supply of oil and natural gas; the price of foreign oil and natural gas imports; the availability of alternate fuel sources; and transportation interruption. Any substantial and extended decline in the price of oil or natural gas could have an adverse effect on the carrying value of our proved reserves, borrowing capacity, our ability to obtain additional capital, and the Company s revenues, profitability and cash flows from operations.

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

A substantial portion of our reserves and production is natural gas. Prices for natural gas have been lower in recent years than at various times in the past and may remain lower in the future. Sustained low prices for natural gas may adversely affect our operations and financial condition.

Natural gas prices have been lower in recent years than at various times in the past. These lower prices may be the result of increased supply resulting from increased drilling in unconventional reservoirs and/or lower demand resulting from changes in economic activity. Natural gas prices may remain at current levels, or fall to lower levels, in the future. Approximately 91% of our estimated net proved reserves is natural gas, and approximately 82% of our production in 2014 was natural gas. Although we expect natural gas production operations on properties we currently own to be profitable at natural gas prices in effect during the past year, a period of sustained low natural gas prices could have adverse effects on our results of operations and financial condition.

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

Our future success will depend 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 analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions may materially affect the quantities and present value of our reserves, see below for a discussion of the uncertainties involved in these processes. Our costs of drilling, completing and operating wells are often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures could be materially and adversely affected by any factor that may curtail, delay or cancel drilling, including the following:

- delays imposed by or resulting from compliance with regulatory requirements;
- unusual or unexpected geological formations;
- unexpected pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment malfunctions, failures or accidents;
- unexpected operational events and drilling conditions;
- pipe or cement failures;
- casing collapses;
- lost or damaged oilfield drilling and service tools;
- loss of drilling fluid circulation;

uncontrollable flows of oil, natural gas and fluids;

fires and natural disasters;

environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures and discharges of toxic gases;

adverse weather conditions;

reductions in oil and natural gas prices;

oil and natural gas property title problems; and

market limitations for oil and natural gas.

If any of these factors were to occur with respect to a particular field, we could lose all or a part of our investment in the field, or we could fail to realize the expected benefits from the field, either of which could materially and adversely affect our revenue and profitability.

We have less experience in drilling wells to the Marcellus Shale (only 36 wells drilled since 2010) and limited information regarding reserves and decline rates in the Marcellus Shale. Wells drilled to this shale are more expensive and more susceptible to mechanical problems in drilling and completion techniques than wells in other conventional areas.

We have drilled only 36 Marcellus Shale wells since 2010, including limited horizontal drilling and completion experience. Other operators in the Marcellus Shale play may have significantly more experience in the drilling and completion of these wells, including the drilling and completion of horizontal wells. In addition, we have limited information with respect to the ultimate recoverable reserves and production decline rates in these areas. The wells drilled in the Marcellus Shale are primarily horizontal and require more stimulation, which makes them more expensive to drill and complete. The wells are also more susceptible to mechanical problems associated with the drilling and completion of the wells, such as casing collapse and lost equipment in the wellbore due to the length of the lateral portions of these unconventional wells. The fracturing of these shale formations will be more extensive and complicated than fracturing geological formations in conventional areas of operation.

Prospects that we decide to drill may not yield oil or natural gas in commercially viable quantities.

Our prospects are in various stages of evaluation. We cannot predict with certainty in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable, particularly in light of the current economic environment. The use of seismic data and other technologies, and the study of producing fields in the same area, will not enable us to know conclusively before drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercially viable quantities. Moreover, the analogies we draw from available data from other wells, more fully explored prospects or producing fields may not be applicable to our drilling prospects.

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The unavailability or high cost of drilling rigs, equipment, supplies, personnel and services could adversely affect our ability to execute on a timely basis our exploration and development plans within our budget.

We may, from time to time, encounter difficulty in obtaining, or an increase in the cost of securing, drilling rigs, equipment, services and supplies. In addition, larger producers may be more likely to secure access to such equipment and services by offering more lucrative terms. If we are unable to acquire access to such resources, or can obtain access only at higher prices, our ability to convert our reserves into cash flow could be delayed and the cost of producing those reserves could increase significantly, which would adversely affect our financial condition and results of operations.

Our reserve estimates may turn out to be incorrect if the assumptions upon which these estimates are based are inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

There are numerous uncertainties inherent in estimating quantities of proved reserves and projected future rates of production and timing of development expenditures, including many factors beyond our control. The reserve data and standardized measures set forth herein represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers often vary. In addition, drilling, testing and production data acquired subsequent to the date of an estimate may justify revising such estimates. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. Further, the estimated future net revenues from proved reserves and the present value thereof are based upon certain assumptions, including geologic success, the timing and identification of future drilling locations, prices, future production levels and costs that may not prove correct over time. Predictions of future production levels, development schedules (particularly with regard to non-operated properties), prices and future operating costs are subject to great uncertainty, and the meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they are based.

The present value of net proved reserves included in this report should not be considered as the market value of the reserves attributable to our properties. In accordance with SEC requirements, we base the present value, discounted at 10%, of the pre-tax future net cash flows attributable to our net proved reserves on the average oil and natural gas prices during the 12-month period before the ending date of the period covered by this report determined as an un-weighted, arithmetic average of the first-day-of the-month price for each month within such period, adjusted for quality and transportation. The costs to produce the reserves remain constant at the costs prevailing on the date of the estimate. Actual current and future prices and costs may be materially higher or lower. In addition, the 10% discount factor, which the SEC requires us to use in calculating our discounted future net revenues for reporting purposes, may not be the most appropriate discount factor based on our cost of capital from time to time and/or the risks associated with our business.

Current SEC requirements also state that proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of initial booking. This rule may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program, particularly as we develop our acreage in the Marcellus Shale in West Virginia. Moreover, we may be required to write down our proved undeveloped reserves if we do not drill and develop those reserves within the required five-year timeframe.

Our operations require significant amounts of capital and additional financing may be necessary in order for us to continue our exploration and development activities, including meeting certain drilling obligations under our existing *lease obligations*

Our cash flow from our reserves may not be sufficient to fund our ongoing activities at all times. From time to time, we may require additional financing in order to carry out our oil and gas acquisitions, exploration and development activities. Failure to obtain such financing on a timely basis could cause us to forfeit our interest in certain properties as a result of not fulfilling our existing drilling commitments. Certain of our undeveloped leasehold acreage is subject to leases that will expire unless production is established or we meet certain capital expenditure and drilling requirements. If our revenues from our reserves decrease as a result of lower oil and natural gas prices or production, it will affect our ability to expend the necessary capital to replace our reserves or to maintain our current production. If our cash flow from operations is not sufficient to satisfy our capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or available to us on favorable terms.

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We have limited control over activities conducted on properties we do not operate.

We own interests in properties that are operated by third parties. The success, timing and costs of drilling, completion, and other development activities on our non-operated properties depend on a number of factors that are beyond our control. Because we have only a limited ability to influence and control the operations of our non-operated properties, we can give no assurances that we will realize our targeted returns with respect to those properties.

Factors beyond our control affect our ability to effectively market production and may ultimately affect our financial results.

The ability to market oil and natural gas depends on numerous factors beyond our control. These factors include:

- the extent of domestic production and imports of oil and natural gas;
- the availability of pipeline, rail and refinery capacity, including facilities owned and operated by third parties;
- the availability of satisfactory transportation arrangements for our oil and natural gas production;
- the proximity of natural gas production to natural gas pipelines;
- the effects of inclement weather;
- the demand for oil and natural gas by utilities and other end users;
- the availability of alternative fuel sources;
- state and federal regulations of oil and natural gas marketing and transportation; and
- federal regulation of natural gas sold or transported in interstate commerce.

Because of these factors and other factors beyond our control, we may be unable to market all of the oil and natural gas that we produce. In addition, we may be unable to obtain favorable prices for the oil and natural gas we produce.

Certain federal income tax deductions currently available with respect to oil and natural gas exploration and development may be eliminated as a result of future legislation.

Congress has recently considered, is considering, and may continue to consider, legislation that, if adopted in its proposed or similar form, would deprive some companies involved in oil and natural gas exploration and production activities of certain U.S. federal income tax incentives and deductions currently available to such companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures.

Deficiencies of title to our leased interests could significantly affect our financial condition.

Our practice in acquiring exploration leases or undivided interests in oil and natural gas leases is not to incur the expense of retaining lawyers to examine the title to the mineral interest prior to executing the lease. Instead, we rely upon the judgment of lease brokers and others to perform the field work in examining records in the appropriate governmental or county clerk s office before leasing a specific mineral interest. This practice is widely followed in the industry. Prior to drilling an exploration well, the operator of the well will typically obtain a preliminary title review of the drill site lease or spacing unit within which the proposed well is to be drilled to identify any obvious deficiencies in title to the well and, if there are deficiencies, to identify measures necessary to cure those defects to the extent reasonably possible. It does happen, from time-to-time, that the examination made by the operator s title lawyers reveals that the lease or leases are invalid, having been purchased in error from a person who is not the rightful owner of the mineral interest desired. In these circumstances, we may not be able to proceed with our exploration and development of the lease site or may incur costs to remedy a defect, which could affect our financial condition and results of operations.

We are subject to complex federal, state and local laws and regulations which could adversely affect our business.

Exploration for and development, exploitation, production and sale of oil and natural gas in the United States are subject to extensive federal, state and local laws and regulations, including complex tax laws and regulations. Existing laws or regulations, as currently interpreted or reinterpreted in the future, or future laws, regulations or incremental taxes and fees, could harm our business, results of operations and financial condition. We may be required to make large expenditures to comply with environmental and other governmental regulations.

It is possible that new taxes on our industry could be implemented and/or tax benefits could be eliminated or reduced, reducing our profitability and available cash flow. In addition to the short-term negative impact on our financial results, such additional burdens, if enacted, would reduce our funds available for reinvestment and thus ultimately reduce our growth and future oil and natural gas production.

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Compliance with environmental and other government regulations could be costly and could negatively impact our production.

Our operations are subject to numerous laws and regulations relating to environmental protection. These laws and regulations may:

- require that we acquire permits before developing our properties;
- restrict the substances that can be released into the environment in connection with drilling, completion and production activities;
- limit or prohibit drilling activities on protected areas such as wetlands or wilderness areas; and
- require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells.

Under these laws and regulations or under the common law, we could be liable for personal injury and clean-up costs and other environmental, natural resource and property damages, as well as administrative, civil and criminal penalties. We could also be affected by more stringent laws and regulations adopted in the future, including any related to climate change, engine emissions, greenhouse gases and hydraulic fracturing. We maintain limited insurance coverage for sudden and accidental environmental damages, but do not maintain insurance coverage for the full potential liability that could be caused by accidental environmental damages. Accordingly, we may be subject to liability in excess of our insurance coverage or may be required to cease production from properties in the event of environmental damages.

Climate change legislation or regulations restricting emissions of greenhouse gases (GHGs) could result in increased operating costs and reduced demand for the oil and gas we produce.

More stringent laws and regulations relating to climate change and GHGs may be adopted and could cause us to incur material expenses to comply. In the absence of comprehensive federal legislation on GHG emission control, the EPA attempted to require the permitting of GHG emissions; although the Supreme Court struck down the permitting requirements, it upheld the EPA s authority to control GHG emissions when a permit is required due to emissions of other pollutants. The EPA also requires the reporting of GHG emissions from specified large GHG emission sources including onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage and distribution facilities, which may include facilities we operate. Reporting of GHG emissions from such facilities is required on an annual basis. We will have to incur costs associated with this reporting obligation.

In addition, the United States Congress has considered legislation to reduce emissions of GHGs and many states have already taken legal measures to reduce or measure GHG emission levels, often involving the planned development of GHG emission inventories and/or regional cap and trade programs. Most of these cap and trade programs require major sources of emissions or major producers of fuels to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to reduce overall GHG emissions. The cost of these allowances could escalate significantly over time. The adoption and implementation of any legislation or regulatory programs imposing GHG reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas that we produce.

Potential physical effects of climate change could adversely affect our operations and cause us to incur significant costs in preparing for or responding to those effects.

In an interpretative guidance on climate change disclosures, the SEC indicates that climate change could have an effect on the severity of weather (including hurricanes and floods), sea levels, the arability of farmland, and water availability and quality. If such effects were to occur, our exploration and production operations, including the hydraulic fracturing of our wells, have the potential to be adversely affected. Potential adverse effects could include disruption of our production activities, including, for example, damages to our facilities from powerful winds or increases in our costs of operation or reductions in the efficiency of our operations, as well as potentially increased costs for insurance coverages in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change.

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We must obtain governmental permits and approvals for our drilling operations, which can be a costly and time consuming process, and may result in delays and restrictions on our operations.

Regulatory authorities exercise considerable discretion in the timing and scope of permit issuance. Requirements imposed by these authorities may be costly and time consuming and may result in delays in the commencement or continuation of our exploration or production operations. For example, we are often required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that proposed exploration for or production of natural gas or oil may have on the environment. Further, the public may comment on and otherwise engage in the permitting process, including through intervention in the courts. Accordingly, the permits we need may not be issued, or if issued, may not be issued in a timely fashion, or may involve requirements that restrict our ability to conduct our operations or to do so profitably.

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

Hydraulic fracturing is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions but is not subject to regulation at the federal level (except for fracturing activity involving the use of diesel). The EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, but the final study has not yet been released. A committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. Legislation was introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. Some states have adopted or are considering adopting regulations requiring disclosure of chemicals in fluids used in hydraulic fracturing or other restrictions on drilling and completion operations, including requirements regarding casing and cementing of wells; testing of nearby water wells; restrictions on access to, and usage of, water; and restrictions on the type of chemical additives that may be used in hydraulic fracturing operations. Any other new laws or regulations that significantly restrict hydraulic fracturing could make it more difficult or costly for us to perform hydraulic fracturing activities and thereby affect our determination of whether a well is commercially viable. In addition, if hydraulic fracturing is regulated at the federal level, our fracturing activities could become subject to additional permit requirements or operational restrictions and also to associated permitting delays and potential increases in costs. We have conducted hydraulic fracturing operations on most of our existing wells, and we anticipate conducting hydraulic fracturing operations on substantially all of our future wells. As a result, restrictions on hydraulic fracturing could reduce the amount of oil and natural gas that we are ultimately able to produce in commercial quantities and adversely affect our operations and financial condition.

Any derivative transactions we enter into may limit our gains and expose us to other risks.

We enter into financial derivative transactions from time to time to manage our exposure to commodity price risks. These transactions limit our potential gains if commodity prices rise above the levels established by our derivative transactions. These transactions may also expose us to other risks of financial losses, for example, if our production is less than we anticipated at the time we entered into a derivative instrument or if a counterparty to our derivative instruments fails to perform its obligations under a derivatives transaction.

The enactment of the Dodd Frank Act could have an adverse impact on our ability to hedge risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act enacted in 2010 (the Dodd-Frank Act) provides for new statutory and regulatory requirements for swaps and other financial derivative transactions, including certain oil and gas hedging transactions. In its rulemaking under the Dodd Frank Act, the Commodity Futures Trading Commission (CFTC) issued final regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions or positions would be exempt from these position limits. In September 2012, The U.S. District Court for the District of Columbia vacated and remanded the rules for position limits adopted by the CFTC in October 2011 based on a necessity finding. Position limits may be imposed upon certain derivative transactions, which may restrict our ability to utilize these products.

The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties or curtail our dealings with that counterparty. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations.

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The rulemaking process under the Dodd-Frank Act has not been completed, and the timeframes for compliance with rules under the Dodd-Frank Act that are effective remain uncertain. Consequently, it is not possible at this time to determine the full effect that the Dodd-Frank Act and the rules and regulations adopted under the Dodd-Frank Act will have on our ability to continue to use the derivative products we currently utilize.

We depend on a relatively small number of purchasers for a substantial portion of our revenue. The inability of one or more of our purchasers to meet their obligations may adversely affect our financial results.

We derive a significant amount of our revenue from a relatively small number of purchasers. Any substituted purchasers may not provide the same level of our revenue in the future for a variety of reasons. The loss of all or a significant part of this revenue would adversely affect our financial condition and results of operations.

Competitive industry conditions may negatively affect our ability to conduct operations.

We compete with numerous other companies in virtually all facets of our business. Our competitors in development, exploration, acquisitions and production include major integrated oil and natural gas companies as well as numerous independents, including many that have significantly greater resources. Therefore, competitors may be able to pay more for desirable leases and evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources permit. We also compete for the materials, equipment and services that are necessary for the exploration, development and operation of our properties. Our ability to increase reserves in the future will be dependent on our ability to select and acquire suitable prospects for future exploration and development.

Factors that affect our ability to compete in the marketplace include:

- our access to the capital necessary to drill and complete wells and acquire properties;
- our ability to acquire and analyze seismic, geological and other information relating to a property;
- our ability to retain the personnel necessary to properly evaluate seismic and other information relating to a property;
- our ability to procure materials, equipment and services required to explore, develop and operate our properties; and
- our ability to access pipelines, and the locations of facilities used to produce and transport oil and natural gas production.

Our operating results are likely to fluctuate significantly and cause our stock price to be volatile which could cause the value of your investment in our shares to decline.

Quarterly and annual operating results are likely to fluctuate significantly in the future due to a variety of factors, many of which are outside of our control. If operating results do not meet the expectations of securities analysts and investors, the trading price of our common stock could significantly decline which may cause the value of your investment to decline. Some of the factors that could affect quarterly or annual operating results or impact the market price of our common stock include:

- our ability to develop properties and to market our oil and gas;
- the timing and amount of, or cancellation or rescheduling of, orders for our oil and gas;
- our ability to retain key management, sales and marketing and engineering personnel;
- a decrease in the prices of oil and gas; and
- changes in costs of exploration or marketing of oil and gas.

Due to these and other factors, quarterly and annual revenues, expenses and results of operations could vary significantly in the future, and period-to-period comparisons should not be relied upon as indications of future performance.

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Our business could be adversely affected by any adverse economic developments in the oil and gas industry and/or the economy in general.

The oil and gas industry is susceptible to significant change that may influence our business development due to a variety of factors, many of which are outside our control. Some of these factors include:

- varying demand for oil and gas;
- fluctuations in price;
- competitive factors that affect pricing;
- attempts to expand into new markets;
- the timing and magnitude of capital expenditures, including costs relating to the expansion of operations;
- hiring and retention of key personnel;
- changes in generally accepted accounting policies, especially those related to the oil and gas industry; and
- new government legislation or regulation.

Any of the above factors or a significant downturn in the oil and gas industry or with economic conditions generally, could have a negative effect on our business and on the price of our common stock.

Our future success depends on retaining existing key employees and hiring and assimilating new key employees. The loss of key employees or the inability to attract new key employees could limit our ability to execute our growth strategy, resulting in lost profitability and a slower rate of growth. We do not carry, nor do we anticipate obtaining, key man insurance on our executives. It would be difficult for us to replace any one of these individuals. In addition, we may need to hire additional key personnel as we grow. We may not be able to identify and attract high quality employees or successfully assimilate new employees into our existing management structure.

If we are unable to manage our growth effectively, our operations and financial performance could be adversely affected.

The ability to manage and operate our business as we execute our anticipated growth will require effective planning. Significant future growth could strain our internal resources, leading to a lower quality of service and other problems that could adversely affect our financial performance. Our ability to manage future growth effectively will also require us to successfully attract, train, motivate, retain and manage new employees and continue to update and improve our operational, financial and management controls and procedures. If we do not manage our growth effectively, our operations could be adversely affected, resulting in slower growth and a failure to achieve or sustain profitability.

Cyber-attacks targeting systems and infrastructure used by the oil and gas industry may adversely impact our operations.

Our business has become increasingly dependent on digital technologies to conduct certain exploration, development, production and financial activities. We depend on digital technology to estimate quantities of oil and gas reserves, process and record financial and operating data, analyze seismic and drilling information, and communicate with our employees and third party partners. Unauthorized access to our seismic data, reserves information or other proprietary information could lead to data corruption, communication interruption, or other operational disruptions in our exploration or production operations. Also, computers control nearly all of the oil and gas distribution systems in the United States and abroad, which are necessary to transport our production to market. A cyber-attack directed at oil and gas distribution systems could damage critical distribution and storage assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for production and settle transactions.

While our operations and financial condition have not been materially and adversely affected by cyber-attacks, there is no assurance that we will not suffer such attacks and resulting losses in the future. Further, as cyber-attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber-attacks.

Risks relating to ownership of our common stock

The price of our common stock is extremely volatile and investors may not be able to sell their shares at or above their purchase price, or at all.

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Our common stock is presently traded on the OTC Bulletin Board, although there is no assurance that a viable market will continue. The price of our shares in the public market is highly volatile and may fluctuate substantially because of:

- actual or anticipated fluctuations in our operating results;
- changes in or failure to meet market expectations;
- conditions and trends in the oil and gas industry; and
- fluctuations in stock market price and volume, which are particularly common among securities of small capitalization companies.

Future sales or the potential for sale of a substantial number of shares of our common stock could cause the market value to decline and could impair our ability to raise capital through subsequent equity offerings.

If we do not generate cash from our operations to finance future business, we may need to raise additional funds through public or private financing opportunities. The issuance of a substantial number of our common shares to individuals or in the public markets, or the perception that these sales may occur, could cause the market price of our common stock to decline and could materially impair our ability to raise capital through the sale of additional equity securities. Any such issuances would dilute the equity interests of existing stockholders.

We do not intend to pay dividends

To date, we have never declared or paid a cash dividend on shares of our common stock. We currently intend to retain any future earnings for growth and development of the business; therefore, we do not anticipate paying any dividends in the foreseeable future.

Possible Penny Stock Regulation

Trading of our common stock on the Bulletin Board may be subject to certain provisions of the Securities Exchange Act of 1934, commonly referred to as the penny stock rule. A penny stock is generally defined to be any equity security that has a market price less than $5.00 per share, subject to certain exceptions. If our stock is deemed to be a penny stock, trading in our stock will be subject to additional sales practice requirements on broker-dealers.

These may require a broker dealer to:

- make a special suitability determination for purchasers of penny stocks;
- receive the purchaser s written consent to the transaction prior to the purchase; and

deliver to a prospective purchaser of a penny stock, prior to the first transaction, a risk disclosure document relating to the penny stock market.

Consequently, penny stock rules may restrict the ability of broker-dealers to trade and/or maintain a market in our common stock. Also, many prospective investors may not want to get involved with the additional administrative requirements, which may have a material adverse effect on the trading of our shares.

Item 1B Unresolved Staff Comments

None.

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Item 2 Properties

Our properties consist of working and royalty interests owned by us in various oil and gas wells and leases located in West Virginia. Our proved reserves as of December 31, 2014 and, 2013, are set forth below:

	As of December 31,							
	2014				2013			
	Oil and Condensates (BBL)	Natural Gas (Mcf)	NGL (BBL)	Mcfe	Oil and Condensates (BBL)	Natural Gas (Mcf)	NGL (BBL)	Mcfe
Developed Producing	9,337	44,937,000	968,283	50,802,720	19,073	34,536,168	890,367	39,992,808
Developed Non-Producing	8,037	17,552,000	300,924	19,405,766		7,999,999		7,999,999
Proved Undeveloped		14,444,121		14,444,121				
Total Proved	17,374	76,933,121	1,269,207	84,652,607	19,073	42,536,167	890,367	47,992,807

All calculations converting oil and condensates to natural gas equivalent have been made using a ratio of one barrel of crude equivalent to six mcf of natural gas. The increase in proved developed reserves is from drilling in the Marcellus Shale formation and not in the traditional shallow well formations. In recent years, the application of lateral well drilling and completion technology has led to the development of the Marcellus Shale. The development of the Marcellus Shale has transformed the Appalachian Basin into one of the country s premier natural gas reserve plays. The horizontal lateral exceeds 2,000 feet in length and typically involves multistage fracturing completions.

Proved undeveloped reserves as of December 31, 2014 and 2013 reflect the Company s net working interest in such reserves that we have both the intent and ability to develop, within five years of initial booking. Our strategy and that of our joint venture partner, Republic, is to maximize potential drilling locations and acreage held by production. As a result, our development plan focuses primarily on drilling probable and possible locations, rather than proved locations. While we plan to fund such capital expenditures with proceeds from the Morgan Stanley Credit Facility, we may pursue other financing alternatives (e.g. farm outs, asset sales, etc.) We may elect to augment the drilling of probable and possible locations by including the drilling of some proved locations in our five year drilling plan, which would enable us to book the reserves associated with those proved locations.

As of December 31, 2014, our proved undeveloped reserves consisted of 4 locations (Jones 2H, Jones 3H, Wright 1H, and Wright 2H). As of December 31, 2012, our proved undeveloped reserves consisted of six gross locations. During 2013, we spent approximately $1.7 million to complete one of these locations, the Martinez 1H, and it is now in the proved developed producing category. With regard to the other five locations, all of which are in Wetzel and Marshall Counties, we have removed them from the proved undeveloped category as of December 31, 2013 due to uncertainty over the timing of their development, which results from the combination of our development strategy and available financial resources as of that date.

A review of our reserves was conducted as of December 31, 2014 and 2013 by Wright and Company, Inc., our independent petroleum consultants. The engineer was selected for their geographic expertise and their historical experience in engineering certain properties. The technical person responsible for reviewing the reserve estimates meets the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. We work closely with our independent petroleum consultants to ensure the integrity, accuracy and timeliness of data furnished to the independent petroleum consultants for their reserves review process. Throughout the year, our technical team meets periodically with representatives from our independent petroleum consultants to review properties and discuss methods and assumptions. While we have no formal committee specifically designated to review reserves reporting and the reserves estimation process, our senior management reviews and approves any internally estimated significant changes to our proved reserves. We provide historical information to our consultants for all of our producing properties such as ownership interest; oil and gas production; well test data; commodity prices and operating and development costs. The consultants perform an independent analysis and differences are reviewed.

All of our reserve estimates are reviewed and approved by the Company s President, John Corp. Mr. Corp is a graduate of Marietta College with a Bachelor of Science in Petroleum Engineering and has over thirty years of experience in the oil & gas industry.

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Effective for the year end 2009 and thereafter, SEC reporting rules require that year-end reserve calculations and future cash inflows be based on the simple average of the first-day-of-the-month price for the previous twelve month period. The benchmark prices as of December 31, 2014 and 2013 used in the above table were as follows:

	Oil (BBL)	**Condensates** (BBL)	**Natural Gas** (MMBTU)	**NGL** (BBL)
2014	$ 94.99	$ 71.61	$ 3.31	$ 41.74
2013	$ 96.78	$ 81.20	$ 3.67	$ 35.36

Such reports are, by their very nature, inexact and subject to changes and revisions. Proved developed reserves are reserves expected to be recovered from existing wells with existing equipment and operating methods. Proved undeveloped reserves are expected to be recovered from new wells drilled to known reservoirs on undrilled acreage for which existence and recoverability of such reserves can be estimated with reasonable certainty, or from existing wells where a relatively major expenditure is required to establish production. No estimates of reserves have been included in any reports to any federal agency other that the SEC in 2014 and 2013. See Note 20, Supplementary Information on Oil and Gas Producing Activities (unaudited) included as part of our consolidated financial statements.

Productive Wells

The following table summarizes the total number of wells to which proved developed reserves are attributed and we own a working interest. Wells are shown on a gross basis.

	As of December 31,			
	2014		2013	
	Oil	Natural Gas	Oil	Natural Gas
Producing Wells		27		23
Non-Producing Wells		11		5
Undrilled Well Locations				
Total Wells and Well Locations		38		28

Our total wells reported in 2013 decreased due to the sale of our shallow wells which closed on January 24, 2013.

Drilling Activity

The following table summarizes completed and producing drilling activity for the past three years. Gross wells reflect the sum of all wells in which we own a working interest. Net wells reflect the sum of our working interests in gross wells.

	During the Year Ended, December 31,		
	2014	2013	2012

	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	12	5.13	5	2.4	8	3.4
Dry						
Exploratory Wells						
Productive						
Dry						
Total	12	5.13	5	2.4	8	3.4

The Woodruff 1H, Woodruff 2H, Blackshere 200H, and Blackshere 201H were drilled in the first quarter of 2014. These wells were completed by the second quarter of 2014 and are reflected in the table above. The Anderson 8H and Anderson 9H were drilled in the second quarter of 2014. These wells were completed by the third quarter of 2014 and are reflected in the table above. The Jones 3H was drilled in the second quarter of 2014 but will not be completed until 2015, and is not reflected in the table above. The Shaver 1H, Shaver 2H, Sivert 1H, and Sivert 2H were drilled in the third quarter of 2014. These wells were completed by the fourth quarter of 2014 and are reflected in the table above. The Wright 1H, Wright 2H, and Michaels 1H were drilled in the fourth quarter of 2014 but will not be completed until 2015, and are not reflected in the table above.

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The Freeland 1H, Freeland 2H, Goshorn 3H, and Goshorn 4H were drilled in the second quarter of 2013. These wells were completed by the fourth quarter of 2013 and are reflected in the table above. The Jones 2H was drilled in the second quarter of 2013 but will not be completed until 2015, and is not reflected in the table above. The Martinez 1H was drilled in the second quarter of 2012 and completed in 2013 and is reflected in the table above. The Beaty 1H and Beaty 2H were drilled in the third quarter of 2013, but were not completed until 2014, and are not reflected in the table above under 2013 but are reflected under 2014.

The Anderson 5H and Anderson 7H, were completed in the first quarter of 2012. The Doman 1H and Doman 2H were drilled in the second quarter of 2012 and were completed in the third quarter of 2012. The Martinez 1H was drilled in the second quarter of 2012 but was not completed until 2013 and is not reflected in the table above under 2012 but is reflected under 2013

The Dewhurst 110H, Dewhurst 111H, Goshorn 1H, and Goshorn 2H were drilled in the fourth quarter of 2011. These wells were completed by the second quarter of 2012, and are reflected in the table above.

Oil and Gas Acreage

The following table summarizes our gross and net developed and undeveloped oil and gas acreage under lease in West Virginia as of December 31, 2014 and 2013.

	Developed Acres		Undeveloped Acres		Total	
	Gross	Net	Gross	Net	Gross	Net
2014	18,939	9,362	21,207	6,094	40,146	15,456
2013	24,099	10,023	23,982	7,840	48,081	17,863

The following table sets forth, for our continuing operations, the gross and net acres of undeveloped acreage that will expire during the periods indicated if not ultimately held by production by drilling efforts:

Year Ending	Expiring Acreage	
December 31,	Gross	Net
2015	1,915	675
2016	7,086	2,015
2017	5,407	1,576
2018	5,355	1,436
2019	1,289	380
2020	155	12
Total	21,207	6,094

It is our intention to purchase assets and/or property for the purpose of enhancing our primary business operations. We are not limited as to the percentage amount of our assets we may use to purchase any additional assets or properties.

Facilities

We currently occupy approximately 4,400 square feet of office space in St. Marys, West Virginia, which we share with our wholly-owned subsidiaries, Prima Oil Company, Inc., Ritchie County Gathering Systems, Inc., Tyler Construction Company, Inc., American Shale Development, Inc., and Tyler Energy, Inc. We lease this space from an unaffiliated third party under a verbal arrangement for $2,000 per month, inclusive of utilities.

Item 3 Legal Proceedings

We may be engaged in various lawsuits and claims, either as plaintiff or defendant, in the normal course of business. In the opinion of management, based upon advice of counsel, the ultimate outcome of these lawsuits will not have a material impact on our financial position or results of operations.

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Certain material pending legal proceedings to which we are a party or to which any of our property is subject, is set forth below:

EQT Corporation

On May 11, 2011, we filed an action in the U.S. District Court for the Northern District of West Virginia against EQT Corporation, a Pennsylvania corporation (Trans Energy, Inc., et al. v. EQT Corporation). The action relates to our attempt to quiet title to certain oil and gas properties referred to as the Blackshere Lease, consisting of approximately 22 oil and/or gas wells on the Blackshere Lease. The defendant, EQT Corporation, has filed with the Court an answer and counterclaim wherein it claims it holds title to the natural gas within and underlying the Blackshere Lease. On November 26, 2012, the Court granted our motion for summary judgment and denied the defendant s motions for declaratory judgment and summary judgment. On February 25, 2014, the United States Court of Appeals for the Fourth Circuit in Richmond Virginia affirmed the summary judgment motion of the U.S. District Court for the Northern District of West Virginia. The defendant s time to appeal this judgment has passed, so this judgment in our favor is final.

On June 12, 2013, EQT Production Company filed a quiet title action in the Circuit Court of Wetzel County, West Virginia. The action relates to a quiet title action relating to a 1,314 acre lease in Wetzel County, West Virginia known as the Robinson lease. On February 28, 2014, the presiding Judge issued an order granting a motion to stay this case pending appeal of the Blackshere case and the same styled case pending in the U.S. District Court of the Northern District of West Virginia.

On July 18, 2013, we filed an action in the U.S. District Court for the Northern District of West Virginia against EQT Production Company. The action relates to a quiet title action relating to a 1,314 acre lease known as the Robinson lease.

Abcouwer

On March 6, 2012, James K. Abcouwer (Abcouwer), former Chief Executive Officer of the Company, filed an action in the Circuit Court of Kanawha County, West Virginia against the Company (James K. Abcouwer vs. Trans Energy, Inc.). The action relates to the Stock Option Agreement (the Agreement) entered into between the Company and Abcouwer on February 7, 2008. By his complaint, Abcouwer alleges that the Company has breached the Agreement by not permitting Abcouwer to exercise options that are the subject of the Agreement. The Company believes that according to the terms of the Agreement all options and other rights described in the Agreement terminated ninety (90) days after the termination of Abcouwer s employment with the Company. Mr. Abcouwer is requesting an amount for his loss of the value of the stock options that are subject to the Agreement. Said amount has not been determined. Abcouwer and the Company filed cross motions for summary judgment, which were heard by the Court in June of 2014. All deadlines in the litigation have been suspended pending rulings on the motions for summary judgment.

On January 14, 2013, Abcouwer filed an action in the Circuit Court of Kanawha County, West Virginia against the Company, and two individual defendants currently on the Board of Directors of the Company William F. Woodburn and Loren E. Bagley. In his complaint, Abcouwer alleges that Plaintiff and Defendants entered into a verbal agreement that required the Company to enter into a third party sales transaction which would have allegedly caused Abcouwer to make significant profit as the result of his ownership of Company stock. Abcouwer alleges that he lost approximately $30 million as a result of the fact that no sale of the Company ever took place. The Company believes that no such agreement existed and that Abcouwer s claims are wholly without merit. On March 25, 2013, the Company filed an answer denying the existence of any liability and asserting, in the alternative, counterclaims for fraud and breach of fiduciary duty. The Company s counterclaims allege that, to the extent a binding agreement between Abcouwer and the Company existed, Abcouwer failed to disclose such agreement to the Company and the SEC despite a duty to do so. The Company has filed a motion for summary judgment which is currently set to be heard on June 18, 2015.

EPA

On October 1, 2014, Trans Energy, Inc. pleaded guilty to three misdemeanor charges related to Unauthorized Discharge into a Water of the United States in violation of the Clean Water Act. In connection with this plea, the Company agreed to pay a $600,000 fine and was placed on probation for a period of two years.

On August 25, 2014, we entered into a civil Consent Decree with the EPA with respect to the Clean Water Act matter and related issues that were discovered based upon an internal audit that we conducted. The Consent Decree requires us to pay a $3,000,000 civil penalty in two installments. The Consent Decree requires us to perform certain restoration activities at the affected pond, well pad and access road sites over a period of three construction seasons. The EPA has estimated that the restoration will cost as much as $13 million, but we intend to perform the work in a manner that will cause our costs to be significantly below this estimate. The Consent Decree also requires us to put in place and maintain an environmental compliance program.

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Item 4 Mine Safety Disclosures

Not Applicable

PART II

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

Our common stock is quoted on the OTC Bulletin Board under the symbol TENG. Set forth in the table below are the quarterly high and low prices of our common stock as obtained from the OTC Bulletin Board for the past two fiscal years.

	High	Low
2014		
First Quarter	$ 4.18	$ 3.45
Second Quarter	$ 4.25	$ 3.60
Third Quarter	$ 4.16	$ 2.61
Fourth Quarter	$ 3.85	$ 1.68
2013		
First Quarter	$ 3.30	$ 2.25
Second Quarter	$ 3.36	$ 2.55
Third Quarter	$ 3.15	$ 2.60
Fourth Quarter	$ 3.95	$ 2.71

As of May 8, 2015, there were approximately 392 holders of record of our common stock. This number does not take into account those shareholders whose certificates are held in the name of broker-dealers or other nominee accounts. We estimate there to be approximately 1,261 such shareholders.

Dividend Policy

We have not declared or paid cash dividends or made distributions in the past, and we do not anticipate that we will pay cash dividends or make distributions in the foreseeable future. In addition, provisions of the Morgan Stanley Credit Agreement restrict our ability to declare dividends. We currently intend to retain and reinvest future earnings to finance operations.

Recent Sales of Unregistered Securities

In January 2014, we issued 25,000 shares of common stock to Jonathan J. Corp, a related party, for the exercise of options at a price of $0.65 per share.

In January 2014, we issued 138,331 shares of common stock to Clarence E. Smith, a 5% Beneficial owner, for the exercise of options at a price of $1.50 per share.

In April 2014, we granted 21,000 shares of stock to three employees under the long-term incentive bonus program. The 21,000 shares are not performance based and vest semi-annually over a three year period. The 21,000 shares were valued at $3.80 per share of common stock using the fair value of the common stock at the date of grant.

In April 2014, we also granted 252,000 common stock options to six employees and five outside board members. These options vest semi-annually over three years and have a five year term. These stock options were granted at an exercise price of $3.80 per common share.

In August 2014, we issued 400,000 shares of common stock to William F. Woodburn, a related party, for the exercise of options at a price of $0.65 per share.

In August 2014, we issued 190,000 shares of common stock to Loren E. Bagley, a related party, for the exercise of options at a price of $0.65 per share.

In August 2014, we issued 75,000 shares of common stock to Mark D. Woodburn, a related party, for the exercise of options at a price of $0.65 per share.

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In August 2014, we issued 10,000 shares of common stock to Brett Greene, a related party, for the exercise of options at a price of $0.65 per share.

In August 2014, we issued 20,998 shares of common stock to Jordan Corp, a related party, for the exercise of options at a price of $0.65 per share.

In August 2014, we issued 62,963 shares of common stock to John G. Corp, a related party, for the exercise of options at a price of $0.65 per share.

In December 2014, we issued 142,857 shares of common stock to Mark D. Woodburn, a related party, for the exercise of options at a price of $0.80 per share.

All of the foregoing issuances were made in reliance upon the exemption provided by Section 4(2) of the Securities Act of 1933.

Item 6 Selected Financial Data

Not applicable.

Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations

The following Management s Discussion and Analysis of Financial Condition and Results of Operations (MD&A) is intended to help the reader understand Trans Energy s financial position, changes in financial condition, and results of operations. MD&A is provided as a supplement to the Company s Consolidated Financial Statements and the accompanying Notes to Consolidated Financial Statements (Footnote or Notes) and should be read in conjunction with the Consolidated Financial Statements and Notes.

Certain statements in this report including, without limitation, statements regarding future financial results and performance, plans and objectives, capital expenditures and the Company s or management s beliefs, expectations or opinions, are forward-looking statements. The Company s forward-looking statements should be read in conjunction with the Company s comments in this report under the heading, Disclosure Regarding Forward-Looking Statements. Actual results may differ materially from those statements as a result of factors, risks and uncertainties over which the Company has no control. For a list of these factors, risks and uncertainties, refer to Item 1A Risk Factors.

Business Strategy

Trans Energy is an independent energy company primarily engaged in the acquisition, exploration, development, and production of oil and natural gas properties, with interests targeting the Marcellus Shale in West Virginia. We successfully increased our drilling program in 2014 and 2013, adding both natural gas and natural gas liquids reserves to the Company s 2014 proved developed reserve base and natural gas and oil reserves to the Company s 2013 proved reserves base. Furthermore, the Company established major interconnects with interstate pipelines to allow increased access to the market.

We intend to focus our development and exploration efforts in our Marcellus Properties and utilize our acreage position to expand our reserve base through continued exploratory and development drilling in the Marcellus Shale during 2015 and beyond. We will evaluate our properties on a continuous basis in order to optimize our existing asset base. We plan to employ the latest drilling, completion and fracturing technology in all of our wells to enhance recoverability and accelerate cash flows associated with these wells. We believe that our acreage position will allow us to grow through horizontal drilling in the near term.

In summary, our strategy is to increase our oil and gas reserves and production while keeping our development costs and operating costs as low as possible. We will implement this strategy through drilling exploratory and development wells from our inventory of available prospects that we have evaluated for geologic and mechanical risk and future reserve or resource potential. The success of this strategy is contingent on various risk factors, as discussed elsewhere in this Form 10-K.

The implementation of our strategy requires that we continually incur significant capital expenditures in order to replace current production and find and develop new oil and gas reserves. In order to finance our capital and exploration program, we depend on cash flow from operations or bank debt and equity offerings as discussed below in Liquidity and Capital Resources.

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Results of Operations

	Fiscal Year Ended December 31, 2014	2013
Total revenues	27,220,818	18,365,558
Total costs and expenses	(35,472,423)	(22,202,993)
Gain on sale of assets	6,902,322	7,015,950
Income (loss) from operations	(1,349,283)	3,178,515
Other expenses	(11,190,978)	(20,913,866)
Income tax expense		
Net loss	(12,540,261)	(17,735,351)

The following table is a summary of revenues, volumes, and pricing for the twelve months ended December 31, 2014 and 2013.

Twelve Months Ended December 31, 2014 compared to the Twelve Months Ended December 31, 2013

	Twelve Months Ended December 31, 2014	2013	Increase/ (Decrease)	
Natural gas sales	$ 22,119,129	$ 14,580,415	$ 7,538,714	51.7%
Oil sales	$ 168,479	$ 160,583	$ 7,896	4.9%
Natural gas liquid sales	$ 4,681,751	$ 3,433,526	$ 1,248,225	36.3%
Total Oil & Gas Sales	$ 26,969,359	$ 18,174,524	$ 8,794,835	48.3%
Transportation and other revenue	$ 251,459	$ 191,034	$ 60,425	31.6%
Total revenue	$ 27,220,818	$ 18,365,558	$ 8,855,260	48.2%
Net Production				
Natural gas sales (Mcf)	6,274,237	3,793,457	2,480,780	65.3%
Oil sales (Bbls)	2,206	1,897	309	16.2%
Natural gas liquids (gallons)	5,356,463	4,224,840	1,131,623	26.7%
Natural Gas Equivalent (Mcfe)	7,052,683	4,408,388	2,644,295	59.9%
Average Sales Price per Unit				
Natural Gas (Mcf)	$ 3.53	$ 3.84	$ (0.31)	(8.0%)
Oil (Bbl)	$ 76.37	$ 84.65	$ (8.28)	(9.7%)
Natural gas liquids (gallons)	$ 0.87	$ .81	$ 0.06	7.4%
Natural Gas Equivalent (Mcfe)	$ 3.82	$ 4.12	$ (0.30)	(7.2%)

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Expenses

All data presented below is derived from costs and production volumes for the relevant period indicated.

	Twelve Months Ended December 31, 2014	2013
Costs and Expenses of Production:		
Production Expenses	$ 11,380,977	$ 8,829,694
Production Taxes	1,762,696	1,390,340
G&A Expenses (Excluding Share-Based Compensation)	11,497,882	4,988,897
Non-Cash Shared-Based Compensation	1,128,676	1,241,701
Depletion of Oil and Natural Gas Properties	9,425,267	5,670,248
Impairment of Oil and Natural Gas Properties		
Depreciation and Amortization	272,088	79,007
Accretion of Discount on Asset Retirement Obligation	4,837	3,106
Costs and Expenses Per Mcfe of Production:		
Production Expenses	$ 1.61	$ 1.97
Production Taxes	0.25	0.34
G&A Expenses (Excluding Share-Based Compensation)	1.63	1.13
Non-Cash Shared-Based Compensation	0.16	0.28
Depletion of Oil and Natural Gas Properties	1.34	1.28
Impairment of Oil and Natural Gas Properties		
Depreciation and Amortization	0.04	0.02
Accretion of Discount on Asset Retirement Obligation		

Total revenues of $27,220,818 for the year ended December 31, 2014 increased $8,855,260 or 48.2% compared to $18,365,558 for the year ended December 31, 2013. The increase in revenue is due to an increase in production volumes on natural gas, natural gas liquids, and oil. We focused our efforts during 2014 and 2013 on the implementation of our drilling program in Marshall and Wetzel Counties, West Virginia. We expect an increase in production from the drilling program throughout 2015.

Production costs increased $2,923,639 or 28.6% for 2014 as compared to 2013, primarily due to an increase in transportation fees and natural gas liquid processing fees, associated with the increased production in NGLs. In lieu of constructing and maintaining a pipeline, the Company has agreed to pay the transporter $0.35 per Mcf to transport a contractual amount of production on the first well drilled on the pad. After the contractual amount is transported, the price reduces to $0.15 per Mcf to transport gas. Any future wells drilled are charged $0.15 per Mcf for transporting the gas produced. We are contractually obligated to provide 2,000,000 MMBTU/mile of lateral extension that must be fulfilled within the first five years in order to reduce our transportation fee per Mcf. If the volumes are not met the transportation fee remains at $0.35 per Mcf.

Depreciation, depletion, amortization and accretion expense increased $3,949,831 or 68.7% for 2014 as compared to 2013, primarily due to higher production volumes and higher year end reserves.

The Company recorded no impairments of its oil and gas properties for the year ended December 31, 2014 or 2013.

Environmental settlement and related costs increased $6,600,000 or 100% due to the settlement related to the Clean Water Act.

Selling, general and administrative expense decreased $204,040 or 3.3% for 2014 as compared to 2013, primarily due to a decrease in legal and professional fees and a decrease in share based compensation for the year.

Gain on sale of assets decreased by $113,628 in 2014 as compared to 2013 due to the gain on sale of Tyler County assets to Antero Resources Corporation in 2013 exceeded the gain resulting from the sale of over-riding royalty interests to Republic Energy Ventures and Wellbore Capital, LLC in 2014.

Our loss from operations for 2014 was $1,349,283 compared to income of $3,178,515 for 2013. This change is primarily due to the settlement related to the Clean Water Act and increased production costs in 2014.

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Interest expense increased $4,734,984 or 31.5% for 2014, as compared to 2013 due to a significantly higher loan balance due to Morgan Stanley as a result of additional borrowings and the Chambers loan refinancing. The average loan balance for 2014 and 2013 was $101,303,895 and $75,979,762 respectively.

Extinguishment/loss on warrant derivative for 2014 was $0.00 compared to a loss of $6,191,722 in 2013. The extinguishment/loss for 2013 was the result of settlement of the warrant derivative liability which was a part of the Chambers Credit Agreement.

We have accumulated approximately $63.6 million of net operating loss carryforwards as of December 31, 2014, which may be offset against future tax obligations through 2033. The use of these losses to reduce future income taxes will depend on the generation of sufficient taxable income prior to the expiration of the net operating loss carryforwards. In the event of certain changes in control, there would be an annual limitation on the amount of net operating loss carryforwards which can be used. We recorded no income tax expense in 2014 or 2013.

No tax benefit has been reported in the financial statements for the year ended December 31, 2014 because the potential tax benefit of the loss carry forward is offset by a valuation allowance of the same amount.

Off Balance Sheet Arrangements

None.

Liquidity and Capital Resources

Historically, we have satisfied our working capital needs with operating revenues, borrowed funds and the proceeds of acreage sales. At December 31, 2014, we have negative working capital of $4,211,011 compared to a positive working capital of $65,897 at December 31, 2013. This decrease in working capital is primarily attributed to an increase in derivative assets which is offset by an increase in accrued expenses.

During 2014, net cash provided by operating activities was $5,927,614 compared to net cash used of $3,760,460 in 2013. This increase in cash flow from operating activities is primarily due to an increase in production from the drilling program combined with reduced production expenses per Mcfe during 2014 compared to 2013.

We expect our cash flow provided by operations for 2015 to increase because of higher projected production from the drilling program, combined with steady operating, general and administrative, interest and financing costs per Mcfe.

Excluding the effects of significant unforeseen expenses or other income, our cash flow from operations fluctuates primarily because of variations in oil and gas production and prices, or changes in working capital accounts and actual well performance. In addition, our oil and gas production may be curtailed due to factors beyond our control, such as downstream activities on major pipelines causing us to shut-in production for various lengths of time.

During 2014, net cash used for investing activities was $13,385,539 compared to net cash used of $18,266,499 in 2013. The reason for the change was an increase in cash proceeds from sales of over-riding royalty interests that was only partially offset by increased expenditures for oil and gas properties during 2014 compared to 2013. See notes 5 and 7 to the financial statements for additional information.

During 2014, net cash provided by financing activities was $6,315,623 compared to net cash provided of $23,745,707 in 2013. This change reflects that the Company s debt increased by a greater amount in 2013 than in 2014. We anticipate meeting our working capital needs with revenues from our ongoing operations and from debt or equity financings.

Inflation

In the opinion of our management, inflation has not had a material overall effect on our operations. However, our Morgan Stanley Credit Agreement is indexed to LIBOR and any increase in LIBOR would affect our interest costs.

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Subsequent Events

On April 3, 2015, we and our wholly owned subsidiaries American Shale and Prima, along with Republic Energy Ventures, LLC, Republic Partners VIII, LLC, Republic Partners VI, LP, Republic Partners VII, LLC, and Republic Energy Operating, LLC (collectively, the Sellers) entered into a Purchase and Sale Agreement (the PSA), pursuant to which the Sellers agreed to sell certain interests located in Wetzel County, West Virginia, including 5,159 net acres held by the Company and the Company s interest in twelve Marcellus producing wellbores, to TH Exploration, LLC (Buyer). The Company expects to receive approximately $47.0 million at closing, net of funds used to repurchase assets that are to be included in the sale. The Company expects it will ultimately receive approximately $71.3 million in connection with the sale of its assets and the overriding royalty interests that are to be repurchased and included in the sale. The incremental funds are expected to be received upon the successful resolution of certain quiet title actions that are currently ongoing and the release of funds that will be held in escrow for a time following the closing.

The PSA contains customary representations, warranties and indemnities among the parties and the closing contemplated by the PSA is subject to the satisfaction of certain customary conditions as described therein. Additionally, the PSA provides Buyer with the opportunity to terminate the agreement and receive its deposit plus reimbursement for diligence expenses in the event that certain conditions are not met. There can be no assurance at this time that all of the conditions may be satisfied.

The sale of the Assets pursuant to the PSA is scheduled to close within approximately ninety days after the signing of the PSA and is to be effective as of October 1, 2014.

The foregoing descriptions of the PSA and the consideration payable hereunder do not purport to be complete and are qualified in their entirety by reference to the complete text of the PSA, a copy of which will be attached as an exhibit to the Company s Form 10-Q for the period ending June 30, 2015.

On April 27, 2015, our wholly owned subsidiary, American Shale entered into a consent and agreement (the Consent and Agreement) that amended the credit agreement dated May 21, 2014 and the associated NPI agreement by and among American Shale, several other financial institutions parties thereto as lenders, and Morgan Stanley Capital Group Inc. as the administrative agent. The Consent and Agreement reduced the contingent borrowing availability under the Tranche B facility from $47.5 million to $10.0 million, and eliminated the Tranche C facility. Potential borrowings under the Tranche B facility had been contingent on American Shale s ability to meet certain levels of PV-10 value for its producing properties, and as such there was no additional availability under Tranche B as of the signing of the Consent and Agreement. There were no other changes to the terms of the Tranche A facility loans under the credit agreement. The NPI agreement was amended to set the contingent NPI percentage at approximately 2.53%.

Under the Consent and Agreement, the administrative agent also consented to the monetization of a portion of American Shale s natural gas hedges and the disposition of a portion of American Shale s working and net revenue interests in wells in Marion County, West Virginia (the Working Interests) that have been recently drilled but not completed.

On the same date, American Shale entered into an agreement with Republic Energy Operating, LLC. Under this agreement, American Shale agreed to use the proceeds from the aforementioned hedge monetization as well as the sale of the Working Interests to pay all amounts due under the March 2015 joint interest billing statement in the amount of approximately $13.8 million provided by Republic Energy Operating, LLC. American Shale reserves the option to reacquire the Working Interests pursuant to a notice of election at agreed upon prices set forth in the agreement.

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Forward-looking and Cautionary Statements

This report includes forward-looking statements. These forward-looking statements may relate to such matters as anticipated financial performance, future revenues or earnings, business prospects, projected ventures, new products and services, anticipated market performance and similar matters. When used in this report, the words may, will, expect, anticipate, continue, estimate, project, intend, and similar expressions are intended to identify forward statements regarding events, conditions, and financial trends that may affect our future plans of operations, business strategy, operating results, and our future plans of operations, business strategy, operating results, and financial position. We caution readers that a variety of factors could cause our actual results to differ materially from the anticipated results or other matters expressed in forward-looking statements. These risks and uncertainties, many of which are beyond our control, include:

- the sufficiency of existing capital resources and our ability to raise additional capital to fund cash requirements for future operations;
- uncertainties involved in the rate of growth of our business and acceptance of any products or services;
- success of our drilling activities;
- volatility of the stock market, particularly within the energy sector;
- the risk factors described elsewhere herein; and
- general economic conditions.

Although we believe the expectations reflected in these forward-looking statements are reasonable, such expectations cannot guarantee future results, levels of activity, performance or achievements.

Critical Accounting Policies

We consider accounting policies related to our estimates of proved reserves, accounting for derivatives, share-based payments, accounting for oil and natural gas properties, asset retirement obligations and accounting for income taxes as critical accounting policies. The policies include significant estimates made by management using information available at the time the estimates are made. However, these estimates could change materially if different information or assumptions were used. These policies are summarized in Note 1 of Notes to Consolidated Financial Statements.

New Accounting Standards

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (Topic 606) (ASU 2014-09). ASU 2014-09 is intended to improve the financial reporting requirements for revenue from contracts with customers by providing a principle based approach. The core principal of the standard is that revenue should be recognized when the transfer of promised goods or services is made in an amount that the entity expects to be entitled to in exchange for the transfer of goods and services. ASU 2014-09 also requires disclosures enabling users of financial statements to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. This standard will be effective for financial statements issued by public companies for annual reporting periods beginning after December 15, 2016. Early adoption is not permitted. In April 2015, the FASB proposed deferring the effective date of ASU 2014-09 by one year. The Company is currently evaluating the potential impact of ASU 2014-09 on the financial statements.

In April 2015 the Financial Accounting Standards Board issued ASU 2015-03, Simplifying the Presentation of Debt Issuance Costs (ASU 2015-03). This standard amends the existing guidance to require that debt issuance costs be presented in the balance sheet as a deduction from the carrying amount of the related debt liability instead of as a deferred charge. ASU No. 2015-03 is effective on a retrospective basis for annual reporting periods beginning after December 15, 2015, but early adoption is permitted. The Company is currently evaluating the effect that the adoption of this standard will have on its financial statements and related disclosures.

The Company has reviewed all other recently issued accounting standards in order to determine their effects, if any, on the consolidated financial statements. Based on that review, the Company believes that none of these standards will have a significant effect on current or future earnings or results of operations.

Item 7A Quantitative and Qualitative Disclosures About Market Risk

Not applicable.

Item 8 Consolidated Financial Statements and Supplementary Data

Our consolidated financial statements as of December 31, 2014 and 2013 and for the fiscal years ended December 31, 2014 and 2013 have been audited to the extent indicated in their report by Maloney + Novotny LLC, independent registered public accounting firm, and have been prepared in accordance with generally accepted accounting principles. The aforementioned financial statements are included herein starting with page F-1.

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

None.

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Item 9A Controls and Procedures

Disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the Exchange Act) are designed to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms and that such information is accumulated and communicated to management, including the Chief Executive Officer and Principal Financial Officer, to allow timely decisions regarding required disclosures.

Evaluation of Controls and Procedures

In connection with the preparation of this Annual Report on Form 10-K, our management, with the participation of our Principal Executive Officer and our Principal Financial Officer, carried out an evaluation of the effectiveness of our disclosure controls and procedures as of December 31, 2014, as required by Rule 13a-15 of the Exchange Act. Based on the evaluation described above, our management, including our principal executive officer and principal financial officer, has concluded that, as of December 31, 2014, our disclosure controls and procedures were ineffective due to i) insufficient financial reporting resources; and ii) insufficient processes and procedures associated with the review of certain underlying data and assumptions used in the reserve report prepared by our third party reserve engineering firm.

Management s Report on Internal Control over Financial Reporting

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. Internal control over financial reporting is a process designed under the supervision of our principal executive and principal financial officers to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

Due to inherent limitations, internal control over financial reporting may not prevent or detect misstatements and, even when determined to be effective, can only provide reasonable, not absolute, assurance with respect to financial statement preparation and presentation. Projections of any evaluation of effectiveness to future periods are subject to risk that controls may become inadequate as a result of changes in conditions or deterioration in the degree of compliance.

Under the supervision and with the participation of our management, including our Principle Executive Officer and Principal Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2014 based on the criteria framework established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

This annual report does not include an attestation report of the Company s registered public accounting firm regarding internal control over financial reporting. Management s report was not subject to attestation by the Company s registered public accounting firm because the Company is a smaller reporting company.

Based on the assessment, our management has concluded that our internal control over financial reporting was ineffective as of December 31, 2014 due to i) insufficient financial reporting resources; and ii) insufficient processes and procedures associated with the review of certain underlying data and assumptions used in the reserve report prepared by our third party reserve engineering firm. The results of management s assessment were reviewed with our Board of Directors. To remediate these issues, our management has retained the services of additional third party consulting personnel and will modify existing internal controls in a manner designed to ensure compliance.

Changes in Internal Control over Financial Reporting

During the period ended, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B Other Information

None.

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PART III

Item 10 Directors, Executive Officers, and Corporate Governance

MANAGEMENT

The following table sets forth the names, ages, and offices held by our directors and executive officers:

Name	Age	Position	Director Since
John G. Corp	55	President and Director	February 2005
Loren E. Bagley	73	Director	August 1991
William F. Woodburn	73	Director	August 1991
Michael R. Guzzetta (a)	57	Treasurer	n/a
Robert L. Richards	69	Director	September 2001
Richard L. Starkey	62	Director	June 2011
Stephen P. Lucado	43	Director\Chairman of the Board	June 2011
Josh L. Sherman	39	Director	September 2012

(a) Mr. Guzzetta was appointed as Treasurer on July 1, 2014.

Information About Directors and Executive Officer

Background information about our directors and executive officers, including information regarding additional experience, qualifications, attributes or skills that led the Board to conclude that the nominee should serve on the Board, is set forth below. There are no family relationships among the nominees or between any nominee and any executive officer of Trans Energy.

John G. Corp, age 55, became a director on February 28, 2005 and was appointed Vice President of Northern Operations in May 2009. Mr. Corp was then appointed to President in July 2010. Mr. Corp has more than 25 years of extensive experience in drilling, production and oilfield service operations in the Appalachian Basin. Prior to joining Trans Energy, Inc., he held various management positions with Belden & Blake Corp. from 1987-2004. He has a BS degree in Petroleum Engineering from Marietta (Ohio) College and is a member of the Society of Petroleum Engineers and the Ohio Oil & Gas Association. Mr. Corp is qualified to serve on our Board due to his significant operational and engineering experience in the oil and gas industry as well as his extensive relationships throughout the industry, particularly within the Appalachian Basin.

Loren E. Bagley, age 73, cofounder, served as our President and CEO from September 1993 to September 2001, at which time he resigned as President and was appointed Vice President. On April 26, 2012, Mr. Bagley resigned his position as Vice President. Mr. Bagley has been actively engaged in the oil and gas business in various capacities for the past thirty years. Prior to becoming involved in the oil and gas industry, Mr. Bagley was employed by the United States government with the Agriculture Department. Mr. Bagley attended Ohio University and Salem College and earned a B.S. Degree. Mr. Bagley s status as cofounder of the Company, a former senior executive, as well as a current major shareholder provide an excellent background with regard to his nomination as a Director. In addition, he has worked in the oil and gas industry within West Virginia for over 20 years.

William F. Woodburn, age 73, cofounder, served as our Vice President from August 1991 to September 2001, at which time he resigned as Vice President and was appointed Secretary / Treasurer. In January 2006, Mr. Woodburn was named as our Chief Operating Officer. Mr. Woodburn resigned his position as Secretary/Treasurer and Chief Operating Officer on April 26, 2012. Mr. Woodburn has been actively engaged in the oil and gas business in various capacities for the past thirty years. Prior to his involvement in the oil and gas industry, Mr. Woodburn was employed by the United States Army Corps of Engineers for twenty four years and was Resident Engineer on several construction projects. Mr. Woodburn graduated from West Virginia University with a B.S. in civil engineering. Mr. Woodburn s status as cofounder of the Company, a former senior executive, as well as a current major shareholder provide an excellent background with regard to his nomination as a Director. In addition, he has worked in the oil and gas industry within West Virginia for over 20 years and currently consults on location and pad site development as well as other operational concerns in the oil and gas industry.

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Robert L. Richards, age 69, became a director and was appointed President and CEO in September 2001. On February 28, 2004, Mr. Richards relinquished his position as CEO, but remained as a director. From 1982 to the present, he has been President of Robert L. Richards, Inc. a consulting geologist firm with 27 years experience in the petroleum industry. He has also served as a geologist with Exxon, exploration geologist with Union Texas Petroleum, and regional exploration manager for Carbonit Exploration, Inc. From 2000 to the present, he has been President and CEO of Derma Rx, Inc., a formulator and marketer of skin care products. Also, from 1992 to August 2000, Mr. Richards was CEO of Kaire Nutraceuticals, Inc., a developer and marketer of health and nutritional products. Mr. Richards served as Vice President of Continental Tax Corporation from March 1989 to August 1992. He has five and one-half years experience in the United States Air Force as an Instructor Pilot. Mr. Richards holds a B.S. degree in geology from Brigham Young University. Mr. Richards has an extensive history with the Company, and has been a long serving Board member as well as a former executive of the Company. His background in petroleum geology as well as his executive experience outside the petroleum industry make him a significant contributor to our Board.

Richard L. Starkey, age 62, became a director on June 29, 2011. He has over 33 years of professional legal experience with an emphasis on oil and gas law. Since 1994, Mr. Starkey has practiced law as a sole practitioner in Parkersburg, West Virginia with an emphasis in oil and gas, real estate and corporate transactions. Mr. Starkey holds a BA degree from the University of Ohio and a Juris Doctor Degree from the University of Cincinnati School of Law. Mr. Starkey has extensive experience in oil and gas law, with a particular experience in the Company s focus area of West Virginia. As such, he provides a unique skill set to our Board.

Stephen P. Lucado, age 43, became a director on June 29, 2011 and was elected Chairman of the Board on April 17, 2012. He has over 18 years of professional financial experience. He has been associated with various financial companies and has managed investments in the oil and gas and power industries. Since 2009, Mr. Lucado has served as Senior Managing Director and Founder of Three Oaks Group, specializing in financial advisory to companies in the oil and gas industry. In 2009, he served as interim CFO of Texas American Resources Company in Austin, Texas, an oil and gas exploration and production company. From 2006 to 2008, Mr. Lucado was a director managing an investment portfolio with Z Capital Partners, LLC in Lake Forest, Illinois. Mr. Lucado holds a Bachelor of Arts Degree in history and science from Harvard University and a Master of Business Administration Degree from the University of Chicago. Mr. Lucado s extensive financial executive experience and contacts within the oil and gas financial community make him very well qualified to serve on our Board.

Josh L. Sherman, age 39, became a director September 4, 2012 and serves as the Chairman of the Audit and Compensation Committees. He has more than 16 years of experience in the oil and gas industry, with an emphasis on financial reporting. He is currently a partner at the energy focused consulting firm, Opportune, LLP, where he leads the firm s complex financial reporting practice. Mr. Sherman currently serves as Chairman of the Audit Committee of the general partner of JP Energy Partners, LP and previously served as Chairman of the Audit Committee of Voyager Oil and Gas, serving from November 2010 until that company s merger in July 2012. Mr. Sherman worked in the audit and global energy markets departments with Deloitte & Touche from January 1997 to August 2002, where he managed the audits of regulated gas and electric utilities, independent power producers and energy trading entities. A Certified Public Accountant and a member of the American Institute of Certified Public Accountants and the National Association of Corporate Directors, Mr. Sherman holds a BBA and a Masters in Accountancy from the University of Texas. Mr. Sherman s background in complex financial reporting and accounting related consulting as well as his focus on the oil and gas industry make him a key contributor to our Board and provides a skill set that serves our shareholders by assisting the Company in its efforts to deliver the highest quality of financial reporting.

Michael R. Guzzetta, age 57, became Treasurer on July 1, 2014. He has 9 years of experience in the petroleum industry and more than 15 years of experience in accounting and finance management, with emphasis on policy and procedure development, and specialized reporting. Past positions include Midwest Business Manager at Time Warner

Media Sales, Corporate Controller at Nicole Energy & Power, and Supervisor of Accounting at Belden & Blake Inc., an exploration and production company. He is a practicing Certified Public Accountant licensed in Ohio since 1997. He has been an adjunct professor at Stark State College in Canton, Ohio and developed accounting classes for the Columbus Adult Education program. Currently he serves on the Finance Committee of the Stark County Board of Developmental Disabilities and has held board positions on the ALS CARE Project and Canton Ballet. Mr. Guzzetta holds a BA in Accounting from Walsh University where he graduated Magna Cum Laude, and an MBA from Capital University.

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SECTION 16(a) BENEFICIAL OWNERSHIP COMPLIANCE

Section 16(a) of the Securities Exchange Act of 1934 requires the Company s executive officers, directors and persons who own more than 10% of the common stock to file initial reports of ownership and changes in ownership with the SEC. To the Company s knowledge, with respect to the fiscal year ended December 31, 2014, all applicable filings were made.

CORPORATE GOVERNANCE

Code of Ethics. The Company has adopted a code of ethics that applies to the Company s chief executive officer, chief financial officer and chief accounting officer. The full text of such code of ethics has been posted on the Company s website at www.transenergyinc.com, and is available free of charge in print to any shareholder who requests it. Request for copies should be addressed to the Secretary at our mailing address 210 Second Street, P.O. Box 393, St. Marys, West Virginia 26170.

Director Nominations. The Board does not currently have a standing nominating committee nor has it adopted a nominating committee charter. The entire Board currently operates as the nominating committee. There is no formal process or policy that governs the manner in which we identify potential candidates for the Board. Historically, the Board has considered several factors in evaluating candidates for nomination to the Board including, but not limited to, the candidate s knowledge of the Company and its business, the candidate s business experience and credentials, and whether the candidate would represent the interests of all our stockholders as opposed to a specific group of stockholders.

Audit Committee. Currently, the audit committee consists of Messrs. Sherman (Chairman), Starkey and Richards. Messrs. Sherman, Starkey and Richards are independent directors within the meaning of Rule 5605(a)(2) of the NASDAQ Stock Market Inc. listing rules. Mr. Sherman, the chairman of the audit committee, serves as the audit committee financial expert. The audit committee examines and reviews, on behalf of the Board, internal financial controls, financial and accounting policies and practices, the form and content of financial reports and statements and the work of the external auditors. The Audit Committee is responsible for hiring, overseeing and terminating the independent registered public accounting firm and determining the compensation of such accountants. The Principal Financial Officer attends the meetings of the Audit Committee by invitation.

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Item 11 Executive Compensation

EXECUTIVE COMPENSATION

The following table sets forth information concerning the compensation earned by our principal executive officer and principal financial officer (Named Executive Officers) during 2014 and 2013:

Name and Principal Position	Year	Salary	Bonus	Stock Awards (1)	Option Awards (2)	All Other Compensation	Total Compensation
John G. Corp (3) (4)	2014	$ 204,261	$ 20,000	$	$ 184,289	$ 15,370	$ 423,921
President	2013	$ 200,554		$ 152,450	$ 249,758	$ 14,934	$ 617,696
Michael R. Guzzetta (3) (4)	2014	$ 58,846		$ 11,700	$ 23,603	$ 10,015	$ 93,164
Treasurer	2013	$ N/A	$ N/A	$ N/A	$ N/A	$ N/A	$ N/A

(1) The amount shown in the table represents the grant date fair value of the restricted stock granted in 2014, computed in accordance with FASB ASC Topic 718. Information regarding assumptions made in valuing the stock awards can be found in Note 13, Stockholders Equity, to the consolidated financial statements included herein.

(2) The amount shown in the table represents the grant date fair value of the stock options granted in 2014, computed in accordance with FASB ASC Topic 718. The fair value of the stock options awarded was determined using the Black-Scholes option pricing model. Information regarding assumptions made in valuing the option grants under this model can be found in Note 13, Stockholders Equity, to the consolidated financial statements included herein.

(3) All other compensation relates to the matching 401k contribution by the Company.

(4) All other compensation includes a housing reimbursement.

No other executive officers received cash compensation greater than $100,000 in any of the past two fiscal years.

We currently have a long-term incentive and bonus program for the benefit of employees and officers of the Company. The program is primarily focused on senior officers, but certain elements of the plan are made available to key managers and to any employee in certain circumstances. In addition, management has established a 401(K) plan for employees and officers of the Company.

Change in Control Termination Agreement

Mr. Corp has a change in control termination agreement. A change of control is defined in the change of control termination agreement to mean when more than 50% of the Company s common shares are sold to a new owner or a group forming a bloc for the purpose of such investment in ownership.

The Change in Control Termination Agreement provides a severance payment equal to twice the annual salary in the event one of the following occurs subsequent to a change in control of the Company, (1) the new ownership of the Company terminates Mr. Corp s employment or demotes him in level of responsibility or moves his place of employment (office) more than 30 miles from St. Marys WV during the 12 month period beginning immediately upon the change in control, such termination or demotion not being the result of good cause , or (2) Mr. Corp voluntarily ends his employment during the 30-day period immediately following the 12-month period described in (1).

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Outstanding Equity Awards at Fiscal Year-End for 2013

The following table sets forth information about outstanding equity awards held by our Named Executive Officers as of December 31, 2014:

		Option Awards				Stock Awards	
Name	Grant Date	Number of Securities Underlying Unexercised Options Exercisable	Number of Securities Underlying Unexercised Options Unexercisable	Options Exercise Price	Options Expiration Date	Number of Shares of Restricted Stock That Have Not Vested	Market Value of Shares of Restricted Stock That Have Not Vested (1)
John G. Corp (2)	10/7/2010	90,000		$ 3.00	10/8/2015		$
	5/26/2011	60,000		$ 2.68	6/30/2016		$
	4/26/2012	300,00		$ 2.30	6/30/2017		
	2/13/2013	66,666	33,334	$ 2.50	6/30/2018		
Michael R. Guzzetta (3)	4/30/2014	6,000	12,000	$ 3.80	6/30/2019	6,000	$ 18,240

(1) The closing price of our common stock on December 31, 2014 was $3.04.

(2) The 33,334 unvested stock options granted to Mr. Corp on February 13, 2013 will vest 50% on each of June 30, 2015 and December 31, 2015

(3) The 12,000 unvested stock options granted to Mr. Guzzetta on April 30, 2014 will vest 25% on each of June 30, 2015, December 31, 2015, June 30, 2016, and December 31, 2016. The 6,000 unvested restricted common stock shares granted to Mr. Guzzetta on April 30, 2014 vest 25% on each of June 30, 2015, December 31, 2015, June 30, 2016, and December 31, 2015.

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Set forth below is the amount paid to each non-executive director of the Company during the year ended December 31, 2014.

DIRECTOR COMPENSATION

Name	Fees earned or paid in cash	Stock awards (1)	Option awards (2)	Non-equity incentive plan compensation	Nonqualified deferred compensation earnings	All other compensation	Total
Loren E. Bagley	27,000		29,935				56,935
William F. Woodburn	36,000		29,935				65,935
Robert L. Richards (3)	18,000		29,935			1,517	49,452
Richard L. Starkey	18,000		29,935				47,935
Stephen P. Lucado (3)	372,337		194,951			48,983	616,271
Josh L. Sherman (3)	36,000	17,500	70,430			180	124,110

(1) The amount shown in the table represents the grant date fair value of the restricted stock granted in 2014, computed in accordance with FASB ASC Topic 718. At December 31, 2014, Mr. Sherman held 5,000 of restricted common shares subject to vesting.

(2) The Amount shown in the table represents the grand date fair value of the stock options granted in 2014, computed in accordance with FASB ASC Topic 718. The fair value of the stock options awarded was determined using the Black-Scholes option pricing model. Information regarding assumptions made in valuing the option grants under this model can be found in Note 13, Stockholders Equity, to the consolidated financial statements for the year ended December 31, 2014 included in the Form 10-K. At December 31, 2014, Messrs. Lucado, Richards, Starkey, Sherman, Woodburn, and Bagley held 33,332, 18,000, 18,000, 46,000, 18,000, and 18,000 common stock options, respectively, subject to vesting.

(3) Fees Earned or Paid in Cash to Messrs. Lucado, Richards, and Sherman includes reimbursed business expenses in the amount of $48,983, $1,517, and $180, respectively.

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

The following table sets forth information, to the best of our knowledge as December 31, 2014, with respect to each person known by us to own beneficially more than 5% of our outstanding common stock, each director, each Named Executive, and all directors and officers as a group. Unless otherwise noted, the address of each person listed below is that of Trans Energy, 210 Second Street, St. Marys, West Virginia 26170.

Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class(1)
5% Beneficial Owners		
James K. Abcouwer, 2006 Kanawha Ave. SE, Charleston, WV 25304	2,256,819(2)	15.5%
Mark D. Woodburn	1,580,067(3)	10.8%
Clarence E. Smith	1,483,797	10.1%
Directors and Officers		
John G. Corp.*	383,163	2.6%
Robert L. Richards*	411,498(4)	2.8%
Loren E. Bagley*	2,381,247(5)	16.3%
William F. Woodburn*	2,653,636(6)	18.2%
Michael R. Guzzetta*	3,000	<1.0%
Richard L. Starkey*	30,000	<1.0%
Stephen P. Lucado*	30,000	<1.0%
Josh L. Sherman*	20,000	<1.0%
All directors and executive officers as a group (8 persons)	5,912,544	39.90%

* Indicates director and/or executive officer at December 31, 2014.
(1) Based upon 14,576,477 shares of common stock outstanding as of December 31, 2014.
(2) Includes 1,287,000 shares of common stock held in the name of the Abcouwer Family Limited Partnership Trust.
(3) Includes 739,956 shares held in the name of MDW Capital, Inc., of which Mr. Woodburn is the CEO and stockholder, and 397,100 shares in the name of Meredith Woodburn, wife of Mr. Woodburn, which Mr. Woodburn disavows beneficial ownership or voting power.
(4) Includes 35,087 shares held in the name of Argene Richards, wife of Mr. Richards.
(5) Includes 33,543 shares held in the name of Carolyn S. Bagley, wife of Mr. Bagley, over which Mrs. Bagley retains voting power, and 803,372 shares in the name of a corporation in which Mr. Bagley is the President and stockholder.
(6) Includes 333,986 shares in the name of Janet L. Woodburn, wife of Mr. Woodburn, over which shares Mrs. Woodburn retains voting power, and 454,230 in the name of two corporations in which William and Janet Woodburn are officers and stockholders.

On March 6, 2012, James K. Abcouwer (Abcouwer), former Chief Executive Officer of the Company, filed an action in the Circuit Court of Kanawha County, West Virginia against the Company (James K. Abcouwer vs. Trans Energy, Inc.). The action relates to the Stock Option Agreement (the Agreement) entered into between the Company and Abcouwer on February 7, 2008. By his complaint, Abcouwer alleges that the Company has breached the Agreement by not permitting Abcouwer to exercise options that are the subject of the Agreement. The Company believes that according to the terms of the Agreement all options and other rights described in the Agreement terminated ninety (90) days after the termination of Abcouwer s employment with the Company. Mr. Abcouwer is requesting an amount for his loss of the value of the stock options that are subject to the Agreement. Said amount has not been determined. Abcouwer and the Company filed cross motions for summary judgment, which were heard by the Court in June of 2014. All deadlines in the litigation have been suspended pending rulings on the motions for summary judgment.

On January 14, 2013, Abcouwer filed an action in the Circuit Court of Kanawha County, West Virginia against the Company, and two individual defendants currently on the Board of Directors of the Company William F. Woodburn and Loren E. Bagley. In his complaint, Abcouwer alleges that Plaintiff and Defendants entered into a verbal agreement that required the Company to enter into a third party sales transaction which would have allegedly caused Abcouwer to make significant profit as the result of his ownership of Company stock. Abcouwer alleges that he lost approximately $30 million as a result of the fact that no sale of the Company ever took place. The Company believes that no such agreement existed and that Abcouwer s claims are wholly without merit. On March 25, 2013, the Company filed an answer denying the existence of any liability and asserting, in the alternative, counterclaims for fraud and breach of fiduciary duty. The Company s counterclaims allege that, to the extent a binding agreement between Abcouwer and the Company existed, Abcouwer failed to disclose such agreement to the Company and the SEC despite a duty to do so. The Company has filed a motion for summary judgment which is currently set to be heard on June 18, 2015.

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EQUITY COMPENSATION PLAN INFORMATION

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (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 security holders			
Equity compensation plans not approved by security holders	3,144,993	$ 2.39	52,500
Total	3,144,993	$ 2.39	52,500

Item 13 Certain Relationships and Related Transactions and Director Independence

Certain Relationships and Related Transactions. The Company does not have a written policy pertaining solely to the approval or ratification of related party transactions. However, it is our policy that any material transactions between us and members of management or their affiliates, must be on terms no less favorable than those available from unaffiliated third parties.

In November 2013, Clarence E. Smith, a 5% Beneficial Owner, issued payment to the Company in the amount of $200,000. Mr. Smith was exercising 138,331 options at a price of $1.50 per share. On January 24, 2014, Mr. Smith s stock was issued. The Company is recognizing interest since the funds were held approximately three months before the stock was actually issued. At December 31, 2013, the $205,314 due to Mr. Smith is recorded as a note payable, related party in the current liability section of the balance sheet.

During 2014 and 2013, the Company conducted business with two companies owned by Clarence E. Smith. Work was awarded the companies after bids were sought and reviewed. The amount of payments total $141,626 and $64,000 for the year of 2014 and 2013, respectively.

Director Independence. Our common stock is currently traded on the OTC Bulletin Board. Accordingly, we are not subject to the rules of any national securities exchange that require that a majority of a listed company s directors and specified committees of the board of directors meet independence standards prescribed by such rules. However, of our seven directors currently serving on the Board, we believe that Robert L. Richards, Richard L. Starkey, and Josh L. Sherman are independent directors within the meaning of Rule 5605(a)(2) of the NASDAQ Stock Market Inc. listing rules. The Board believes this leadership structure provides effective and clear leadership for the Company.

Item 14 Principal Accounting Fees and Services

Audit Fees. Audit fees (including expenses) billed to the Company by Maloney + Novotny LLC were $243,167 in fiscal year 2014, and $196,405 in fiscal year 2013. The increase fees in 2014 reflect additional time spent by our auditor in reviewing our 2014 transactions (sale of assets), new financing and derivatives, and increased activity. Audit fees include professional services with respect to the audit of the Company s consolidated financial statements included in our Annual Report on Form 10-K and review of financial statements included in our Quarterly Reports on Form 10-Q. These services are normally provided by Maloney + Novotny LLC in connection with statutory and regulatory filings performed by Maloney + Novotny LLC to comply with generally accepted auditing standards, as well as fees for the audit of the Company s internal control over financial reporting, as required by Section 404 of the Sarbanes-Oxley Act of 2002.

Audit-Related Fees. Audit-related fees (including expenses) billed to the Company by Maloney + Novotny LLC were $0 in both fiscal years 2014 and 2013.

Tax Fees. Tax fees (including expenses) billed to the Company by Maloney + Novotny LLC were $22,109 in fiscal year 2014 and $14,978 in fiscal year 2013.

All Other Fees. All other fees billed by our auditors were $2,523 related to 2013 COSO adoption requirements and the EPA settlement.

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The Board has adopted procedures for pre-approving all audit and permissible non-audit services provided by the independent registered public accountants. The Board will annually review and pre-approve the audit, review and attest services to be provided during the next audit cycle by the independent registered public accountants and may annually review and pre-approve permitted non-audit services to be provided during the next audit cycle by the independent registered public accountants.

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PART IV

Item 15 Exhibits and Financial Statement Schedules

Exhibit No.	Exhibit Name
10.1	Credit Agreement dated as of May 21, 2014, among American Shale Development, Inc., the lenders party thereto from time to time and Morgan Stanley Capital Group, I. as Administrative Agent and Arranger (incorporated by reference to Exhibit 10.1 to the Company s Form 8-K filed on May 22, 2014.)
10.2	Conveyance and Agreement of Net Profits Interest dated as of May 21, 2014, by and among American Shale Development, Inc. and Morgan Stanley Capital Group Inc. (incorporated by reference to Exhibit 10.2 to the Company s Form 8-K filed on May 22, 2014.)
10.3	Purchase and Sale Agreement dated May 20, 2014, between American Shale Development, Inc. and Republic Partners VIII, LLC (incorporated by reference to Exhibit 10.3 to the Company s Form 8-K filed on May 22, 2014.)
31.1	Certification of Principal Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification of Principal Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification of Principle Executive Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of Principal Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1	Independent Engineer Resource Report by Wright and Company, Inc. for the year ended December 31, 2014.
**101.INS	XBRL Instance Document
**101.SCH	XBRL Taxonomy Extension Schema
**101.CAL	XBRL Taxonomy Extension Calculation Linkbase
**101.DEF	XBRL Taxonomy Extension Definition Linkbase
**101.LAB	XBRL Taxonomy Extension Label Linkbase
**101.PRE	XBRL Taxonomy Extension Presentation Linkbase

** Filed herewith.

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SIGNATURES

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

TRANS ENERGY, INC.

By /s/ John G. Corp
John G. Corp,
President and Principal Executive Officer
Dated: May 11, 2015

In accordance with the Exchange Act, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ John G. Corp	President and Director	May 11, 2015
John G. Corp	(Principal Executive Officer)	
/s/ Michael R. Guzzetta	Treasurer	May 11, 2015
Michael R. Guzzetta	(Principal Financial Officer)	
/s/ Loren E. Bagley	Director	May 11, 2015
Loren E. Bagley		
/s/ William F. Woodburn	Director	May 11, 2015
William F. Woodburn		
/s/ Josh L. Sherman	Director	May 11, 2015
Josh L. Sherman		
/s/ Richard L. Starkey	Director	May 11, 2015
Richard L. Starkey		
/s/ Stephen P. Lucado	Director	May 11, 2015
Stephen P. Lucado		

/s/ Robert L. Richards	Director	May 11, 2015
Robert L. Richards		

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TRANS ENERGY, INC. AND SUBSIDIARIES

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors

Trans Energy, Inc.

St. Marys, West Virginia

We have audited the accompanying consolidated balance sheets of Trans Energy, Inc. and subsidiaries (the Company) as of December 31, 2014 and 2013, and the related consolidated statements of operations, stockholders equity and cash flows for the years then ended. 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 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit 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 financial position of Trans Energy, Inc. and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

/s/ Maloney + Novotny LLC
Maloney + Novotny LLC

Cleveland, Ohio

May 11, 2015

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TRANS ENERGY, INC. AND SUBSIDIARIES

Consolidated Balance Sheets

	December 31, 2014	December 31, 2013
ASSETS		
CURRENT ASSETS		
Cash	$ 1,585,530	$ 2,727,832
Accounts receivable, trade	4,248,152	4,460,535
Accounts receivable, related parties	18,500	18,500
Derivative assets	5,420,309	
Advance royalties	68,133	16,937
Prepaid expenses	767,233	1,065,061
Deferred financing costs, net of amortization of $599,971 and $1,308,817, respectively	1,051,671	817,938
Total current assets	13,159,528	9,106,803
OIL AND GAS PROPERTIES, USING SUCCESSFUL EFFORTS ACCOUNTING		
Proved properties	88,194,425	77,961,183
Unproved properties	5,728,196	15,092,783
Pipelines	1,259,052	1,397,440
Accumulated depreciation, depletion and amortization	(17,731,699)	(14,473,069)
Oil and gas properties, net	77,449,974	79,978,337
PROPERTY AND EQUIPMENT, net of accumulated depreciation of $364,710 and $317,704, respectively	504,526	587,218
OTHER ASSETS		
Assets held for sale	14,301,375	
Derivative assets	2,809,847	
Deferred financing costs	3,155,014	139,076
Other assets	388,881	303,887
Total other assets	20,655,117	442,963
TOTAL ASSETS	$ 111,769,145	$ 90,115,321

See notes to consolidated financial statements.

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TRANS ENERGY, INC. AND SUBSIDIARIES

Consolidated Balance Sheets (continued)

	December 31, 2014	December 31, 2013
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES		
Accounts payable, trade	$ 531,761	$ 632,795
Accounts payable due to drilling operator	5,777,983	2,698,302
Accounts payable, related party	1,500	1,500
Accrued expenses	7,429,874	5,302,816
Environmental settlement and related costs	3,600,000	
Revenue payable	25,019	127,106
Commodity derivative liability		58,176
Notes payable, current	4,402	14,897
Notes payable, related party		205,314
Total current liabilities	17,370,539	9,040,906
LONG-TERM LIABILITIES		
Notes payable, net	109,539,647	89,204,102
Asset retirement obligations	90,928	41,440
Environmental settlement and related costs	3,000,000	
Commodity derivative liability	716,488	67,597
Deferred revenue	62,510	
Total long-term liabilities	113,409,573	89,313,139
Total liabilities	130,780,112	98,354,045
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS EQUITY		
Preferred stock 10,000,000 shares authorized at $0.001 par value; -0- shares issued and outstanding		
Common stock 500,000,000 shares authorized at $0.001 par value; 14,578,467 and 13,457,978 shares issued, and 14,576,467 and 13,455,978 shares outstanding, respectively	14,578	13,458
Additional paid-in capital	44,323,190	42,556,292
Treasury stock, at cost, 2,000 shares	(1,950)	(1,950)
Accumulated deficit	(63,346,785)	(50,806,524)
Total stockholders equity (deficit)	(19,010,967)	(8,238,724)

TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 111,769,145	$ 90,115,321

See notes to consolidated financial statements.

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TRANS ENERGY, INC. AND SUBSIDIARIES

Consolidated Statements of Operations

	For the Year Ended December 31, 2014	2013
OPERATING REVENUES		
Oil and gas sales	$ 26,969,359	$ 18,174,524
Gas transportation, gathering, and processing	161,975	158,937
Other income	89,484	32,097
Total operating revenues	27,220,818	18,365,558
OPERATING COSTS AND EXPENSES		
Production costs	13,143,673	10,220,034
Depreciation, depletion, amortization, and accretion	9,702,192	5,752,361
Environmental settlement and related costs	6,600,000	
Selling, general, and administrative	6,026,558	6,230,598
Total operating costs and expenses	35,472,423	22,202,993
Gain on sale of assets	6,902,322	7,015,950
(LOSS) INCOME FROM OPERATIONS	(1,349,283)	3,178,515
OTHER INCOME (EXPENSES)		
Interest income	3,090	19,090
Interest expense	(19,782,603)	(15,047,619)
Extinguishment/loss on warrant derivatives		(6,191,722)
Gain on commodity derivative	8,588,535	306,385
Total other income (expenses)	(11,190,978)	(20,913,866)
NET LOSS BEFORE INCOME TAXES	(12,540,261)	(17,735,351)
INCOME TAX BENEFIT (EXPENSE)		
NET LOSS	$ (12,540,261)	$ (17,735,351)
NET LOSS PER SHARE BASIC AND DILUTED	$ (0.90)	$ (1.34)
WEIGHTED AVERAGE SHARES BASIC AND DILUTED	13,910,016	13,281,859

See notes to consolidated financial statements.

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TRANS ENERGY, INC. AND SUBSIDIARIES

Consolidated Statements of Stockholders Equity

For the years ended December 31, 2014 and 2013

	Common Stock Shares	Common Stock Amount	Additional Paid in Capital	Treasury Stock	Accumulated Deficit	Total
Balance, December 31, 2012	13,238,228	$ 13,238	$ 41,131,636	$ (1,950)	$ (33,071,173)	$ 8,071,751
Shares issued for services	151,750	152	414,848			415,000
Stock option compensation expense			826,701			826,701
Stock options exercised	30,500	30	81,520			81,550
Stock issued	37,500	38	101,587			101,625
Net loss					(17,735,351)	(17,735,351)
Balance, December 31, 2013	13,457,978	$ 13,458	$ 42,556,292	$ (1,950)	$ (50,806,524)	$ (8,238,724)
Shares issued for services	55,350	55	160,349			160,404
Stock option compensation expense			799,419			799,419
Stock options exercised	1,065,139	1,065	807,130			808,195
Net loss					(12,540,261)	(12,540,261)
Balance, December 31, 2014	14,578,467	$ 14,578	$ 44,323,190	$ (1,950)	$ (63,346,785)	$ (19,010,967)

See notes to consolidated financial statements.

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TRANS ENERGY, INC. AND SUBSIDIARIES

Consolidated Statements of Cash Flows

	For the Year Ended December 31, 2014	For the Year Ended December 31, 2013
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ (12,540,261)	$ (17,735,351)
Adjustments to reconcile net loss to net cash provided (used) by operating activities:		
Depreciation, depletion, amortization, and accretion	9,702,192	5,752,361
Amortization of deferred financing cost and debt discount	8,426,119	4,809,081
Share-based compensation	959,823	1,241,701
Gain on sale of assets	(6,902,322)	(7,015,950)
Unrealized gain on derivatives	(7,639,441)	(682,505)
Interest and legal expense added to principal	1,818,240	4,591,088
Realized (gain) loss on warrant derivatives	(949,094)	7,000,000
Changes in operating assets and liabilities:		
Accounts receivable, trade	835,263	(1,086,705)
Noncurrent other assets	(84,994)	(1,964)
Prepaid expenses and other current assets	246,632	(452,950)
Accounts payable and accrued expenses	5,495,034	73,206
Accounts payable drilling operator		(153,904)
Environmental settlement and related costs	6,600,000	
Revenue payable	(39,577)	(98,568)
Net cash provided (used) by operating activities	5,927,614	(3,760,460)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Proceeds from sale of assets	19,332,078	11,451,244
Expenditures for oil and gas properties	(32,709,147)	(29,708,602)
Expenditures for property and equipment	(8,470)	(9,141)
Net cash used for investing activities	(13,385,539)	(18,266,499)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Issuance of common stock		101,625
Stock options exercised	808,195	81,550
Financing costs paid	(4,806,656)	(122,230)
Payment on warrant derivative liability		(1,500,000)
Proceeds from notes payable	113,093,750	25,000,000
Proceeds from notes payable - related party		205,314
Payments on notes payable	(102,779,666)	(20,552)
Net cash provided by financing activities	6,315,623	23,745,707

NET CHANGE IN CASH		(1,142,302)		1,718,748
CASH, BEGINNING OF YEAR		2,727,832		1,009,084
CASH, END OF YEAR	$	1,585,530	$	2,727,832

See notes to consolidated financial statements.

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TRANS ENERGY, INC. AND SUBSIDIARIES

Consolidated Statements of Cash Flows

SUPPLEMENTAL DISCLOSURES FOR CASH FLOW INFORMATION

CASH PAID FOR:		
Interest	$ 11,623,165	$ 6,016,039
Income Taxes		
Non-cash investing and financing activities		
Accrued expenditures for oil and gas properties	3,079,681	2,344,893
Increase in asset retirement obligation	49,488	13,123
Warrant extinguishment added to loan		7,500,000

See notes to consolidated financial statements.

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TRANS ENERGY, INC. AND SUBSIDIARIES

Notes to Consolidated Financial Statements

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations and Organization

Trans Energy, Inc. (Trans Energy or the Company) is an independent energy company engaged in the acquisition, exploration, development, and production of oil and natural gas. Its operations are presently focused in the State of West Virginia.

Principles of Consolidation

The consolidated financial statements include Trans Energy and our wholly-owned subsidiaries, Prima Oil Company, Inc. (Prima), Ritchie County Gathering Systems, Inc., Tyler Construction Company, Inc., American Shale Development, Inc. (American Shale), and Tyler Energy, Inc., and interest with joint venture partners, which are accounted for under the proportioned consolidation method. All significant inter-company balances and transactions have been eliminated in consolidation.

Use of Estimates

The preparation of financial statements in conformity with GAAP 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 financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Our financial statements are based on a number of significant estimates, including oil and gas reserve quantities which are the basis for the calculation of depreciation, depletion, amortization, and impairment of oil and gas properties and timing and costs associated with its asset retirement obligations, estimates of fair value of derivative instruments and estimates used in stock-based compensation calculations. Reserve estimates are by their nature inherently imprecise.

Cash

Financial instruments that potentially subject us to a concentration of credit risk include cash. At times, amounts may exceed federally insured limits and may exceed reported balances due to outstanding checks. Management does not believe it is exposed to any significant credit risk on cash.

Receivables

Accounts receivable are carried at their expected net realizable value. The allowance for doubtful accounts is based on management s assessment of the collectability of specific customer accounts and the aging of the accounts receivables. If there were a deterioration of a major customer s creditworthiness, or actual defaults were higher than historical experience, estimates of the recoverability of the amounts due could be overstated, which could have a negative impact on operations. No allowance for doubtful accounts is deemed necessary at December 31, 2014 and December 31, 2013 by management and no bad debt expense was incurred during the years ended December 31, 2014 and 2013.

Financing Cost

In connection with obtaining the Morgan Stanley financing in May 2014 and subsequent borrowings, we incurred fees and expenses of $4,806,656. These fees and expenses were recorded as financing costs and are being amortized over the life of the loan using the straight-line method, which approximates the effective interest method.

In October 2013 we reached a settlement with Oppenheimer & Co., Inc. (Opco) which related to the amount of the fee which was earned by Opco acting as our investment banker in assisting the Company in obtaining funding (Tranche A) with Chambers Energy Capital (Chambers). We recorded $401,625 in financing fees related to the settlement. The Opco financing fees were being amortized over the same period as the Tranche A loan. In addition, when we obtained new financing in February 2013 and April 2012, we incurred $122,230 in fees during 2013 and $1,741,976 in 2012. These fees were recorded as financing costs and were being amortized over the life of the loan using the straight-line method, which approximates the effective interest method. When we obtained the Morgan Stanley financing, the remaining balance of the finance fees related to the Chambers financing were expensed due to the payoff of the related loan.

Amortization of financing costs for the years ended December 31, 2014 and 2013 was $1,390,924 and $906,292, respectively. Our policy is to recognize twelve months of future deferred financing cost amortization as a current asset and the remaining balance of deferred financing costs as other assets in the consolidated balance sheets.

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Property and Equipment

Property and equipment are recorded at cost. Depreciation on vehicles, machinery and equipment is computed using the straight-line method over expected useful lives of five to ten years. Additions are capitalized and maintenance and repairs are charged to expense as incurred.

Oil and Gas Properties

Trans Energy uses the successful efforts method of accounting for oil and gas producing activities. Under the successful efforts method, costs to acquire mineral interests in oil and gas properties, to drill and equip exploratory wells that find proved reserves, and to drill and equip development wells and asset retirement costs are capitalized. Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs, and costs of carrying and retaining unproved properties are expensed as incurred.

Unproved oil and gas properties that are individually significant are periodically assessed for impairment of value, and a loss is recognized at the time of impairment by providing an impairment allowance. Other unproved properties are amortized based on Trans Energy s experience of successful drilling and average holding period. Capitalized costs of producing oil and gas properties, after considering estimated dismantlement and abandonment costs and estimated salvage values, are depreciated and depleted by the unit-of-production method. Depreciation on pipelines and related equipment, including compressors, is computed using the straight-line method over the expected useful lives of ten to twenty-five years.

On the sale or retirement of a proved property, the cost and related accumulated depreciation, depletion, and amortization are eliminated from the property accounts, and the resultant gain or loss is recognized.

On the sale of an entire interest in an unproved property for cash or cash equivalent, gain or loss on the sale is recognized, taking into consideration the amount of any recorded impairment if the property had been assessed individually.

If a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained.

Impairments

Generally accepted accounting principles require that long-lived assets (including oil and gas properties) and certain identifiable intangibles are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. The Company, at least annually, reviews its proved oil and gas properties for impairment by comparing the carrying value of its properties to the properties undiscounted estimated future net cash flows. Estimates of future oil and gas prices, operating costs, and production are utilized in determining undiscounted future net cash flows. The estimated future production of oil and gas reserves is based upon the Company s independent reserve engineer s estimate of proved reserves, which includes assumptions regarding field decline rates and future prices and costs. For properties where the carrying value exceeds undiscounted future net cash flows, the Company recognizes as impairment the difference between the carrying value and fair market value of the properties.

In January 2013, the Company sold certain shallow wells for approximately $2.6 million. We determined that the sales price negotiated with the independent buyer represented the fair market value of those properties as of December 31, 2012. Accordingly, the Company recorded an impairment of approximately $10.1 million in 2012 so that the carrying value of those properties as of December 31, 2012 was equal to the subsequent sales price.

No impairments were recorded in 2014 and 2013.

Derivatives

We may enter into derivative commodity contracts at times to manage or reduce commodity price risk related to our production. Derivatives and embedded derivatives, if applicable, are measured at fair value and recognized in the consolidated balance sheets as assets or liabilities. Derivatives are classified in the consolidated balance sheets as current or non-current based on whether net-cash settlement is expected to be required within 12 months of the balance sheet date. These commodity contracts are not designated as cash flow hedges, so changes in the fair value are recognized immediately in other income (expense) in the consolidated statement of operations. The pricing models used for valuation often incorporate significant estimates and assumptions, which may impact the level of precision in the financial statements.

We have determined that the warrant previously issued for equity of one of our wholly-own subsidiaries was a derivative liability prior to being settled in December 2013.

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Notes Payable

We record notes payable at fair value and recognize interest expense for accrued interest payable under the terms of the agreements. Principal and interest payments due within one year are classified as current, whereas principal and interest payments for periods beyond one year are classified as long term.

Asset Retirement Obligations

We record the fair value of a liability for an asset retirement obligation in the period in which it is incurred if a reasonable estimate of fair value can be made. These obligations include dismantlement, plugging and abandonment of oil and gas wells and associated pipelines and equipment. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depleted over the estimated useful life of the related asset which has been determined to be 40 years for Marcellus Shale wells.

The following is a description of the changes to our asset retirement obligations for the twelve months ended December 31:

	2014	2013
Asset retirement obligations at beginning of period	$ 41,440	$ 416,322
Liabilities incurred during the period	45,488	4,259
Accretion expense	4,000	4,124
Liability revisions		4,740
Liabilities held for sale		(388,005)
Asset retirement obligations at end of period	$ 90,928	$ 41,440

At December 31, 2014 and 2013, the Company s current portion of the asset retirement obligation was $0. In addition, $388,005 of asset retirement obligations are reported as liabilities held for sale as of December 31, 2012.

The revisions in the 2012 estimated liabilities were the result of changes in numerous assumptions and judgments including the ultimate retirement costs, inflation factors, credit-adjusted discount rates, and timing of retirement. The revisions in the 2013 estimated liabilities are the result of a change in the ultimate retirement cost.

Income Taxes

At December 31, 2014, the Company had net operating loss carry forwards (NOLs) for future years of approximately $63.6 million. These NOLS will expire at various dates through 2033. There is no current tax provision for the year ended December 31, 2014 due to a net operating loss for the period. No tax benefit has been recorded in the consolidated financial statements for the remaining NOLs or Alternative Minimum Tax (AMT) credit since the potential tax benefit is offset by a valuation allowance of the same amount. Utilization of the NOLs could be limited if there is a substantial change in ownership of the Company and is contingent on future earnings.

We have provided a valuation allowance equal to 100% of the total net deferred asset in recognition of the uncertainty regarding the ultimate amount of the net deferred tax asset that will be realized.

The Company has no material unrecognized tax benefits. No tax penalties or interest expense were accrued as of December 31, 2014 or 2013 or paid during the periods then ended. We file tax returns in the United States and states in which we have operations and are subject to taxation. Tax years subsequent to 2010 remain open to examination by U.S. federal and state tax jurisdictions, however prior year net operating losses remain open for examination.

Revenue and Cost Recognition

We recognize gas revenues upon delivery of the gas to the customers pipeline from our pipelines when recorded as received by the customer s meter. We recognize oil revenues when pumped and metered by the customer. We use the sales method to account for sales and imbalances of natural gas. Under this method, revenues are recognized based on actual volumes sold to purchasers. The volumes sold may differ from the volumes to which we are entitled based on our interest in the properties. These differences create imbalances which are recognized as a liability only when the imbalance exceeds the estimate of remaining reserves. We had no material imbalances as of December 31, 2014 and 2013. Costs associated with production are expensed in the period incurred.

Revenue payable represents cash received but not yet distributed to third parties.

Transportation revenue is recognized when earned and we have a contractual right to receive payment.

On January 1, 2013, the Company adopted new authoritative accounting guidance issued by the Financial Accounting Standards Board (FASB), which enhanced disclosures by requiring an entity to disclose information about netting arrangements, including rights of offset, to enable users of its financial statements to understand the effect of those arrangements on its financial position and provided clarification as to the specific instruments that should be considered in these disclosures. These pronouncements were issued to facilitate comparison between financial statements prepared on the basis of GAAP and International Financial Reporting Standards. These disclosures are effective for annual and interim reporting periods beginning on or after January 1, 2013, and are to be applied retrospectively for all comparative periods presented. See Note 11 Derivative and Hedging Financial Instruments for tabular presentation of the Company s gross and net derivative positions.

Share-Based Compensation

Trans Energy estimates the fair value of each stock option award at the grant date by using the Black-Scholes option pricing model. The model employs various assumptions, based on management s best estimates at the time of the grant, which impact the fair value calculated and ultimately, the expense that is recognized over the life of the award. We have utilized historical data and analyzed current information to reasonably support these assumptions. The fair value of restricted stock awards is determined based on the fair market value of our common stock on the date of the grant.

We recognize share-based compensation expense on a straight-line basis over the requisite service period for the entire award. As a result of stock and option transactions, we recorded total share-based compensation of $959,823 and $1,241,701 for the years ended December 31, 2014 and 2013, respectively.

New Accounting Standards

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (Topic 606) (ASU 2014-09). ASU 2014-09 is intended to improve the financial reporting requirements for revenue from contracts with customers by providing a principle based approach. The core principal of the standard is that revenue should be recognized when the transfer of promised goods or services is made in an amount that the entity expects to be entitled to in exchange for the transfer of goods and services. ASU 2014-09 also requires disclosures enabling users of financial statements to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. This standard will be effective for financial statements issued by public companies for annual reporting periods beginning after December 15, 2016. Early adoption is not permitted. In April 2015, the FASB proposed deferring the effective date of ASU 2014-09 by one year. The Company is currently evaluating the potential impact of ASU 2014-09 on the financial statements.

In April 2015 the Financial Accounting Standards Board issued ASU 2015-03, Simplifying the Presentation of Debt Issuance Costs (ASU 2015-03). This standard amends the existing guidance to require that debt issuance costs be presented in the balance sheet as a deduction from the carrying amount of the related debt liability instead of as a deferred charge. ASU No. 2015-03 is effective on a retrospective basis for annual reporting periods beginning after December 15, 2015, but early adoption is permitted. The Company is currently evaluating the effect that the adoption of this standard will have on its financial statements and related disclosures.

The Company has reviewed all other recently issued accounting standards in order to determine their effects, if any, on the consolidated financial statements. Based on that review, the Company believes that none of these standards will have a significant effect on current or future earnings or results of operations.

Reclassification

Certain reclassifications have been made to the 2013 financial presentation to correspond to the current year s format.

NOTE 2 OPERATIONS

We have incurred net losses for the years ended December 31, 2014 and 2013 of $(12,540,261) and $(17,735,351), respectively. Although our current and prior year-to-date revenues were not sufficient to cover our operating costs and interest expense, we are focusing on drilling Marcellus Shale wells which based upon projections, are expected to increase our cash flow. If our cash flows from operations are not sufficient to meet liquidity requirements, we may need to sell assets, obtain additional financing or issue equity.

Our net losses and cash flows used in operating and investing activities during the years ended December 31, 2014 and 2013 were primarily funded using net proceeds from notes payable to Chambers and Morgan Stanley (see Note 10), in addition to proceeds from the sale of certain oil and gas properties (see Note 7).

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NOTE 3 ACCOUNTS PAYABLE DUE TO DRILLING OPERATOR

We have historically been the drilling operator for wells drilled on our behalf and other third parties in which we own a working interest. In 2012, another working interest owner became the drilling operator for wells in which we own a working interest. We owed the drilling operator $5,777,983 and $2,698,302 for charges incurred, but not paid, as of December 31, 2014 and 2013, respectively. The amount due to the operator reported at December 31, 2014 has been reduced for consideration received from the Republic purchase and sale agreement, which is to be paid in the form of a credit against the expenses incurred by Republic Energy Ventures on behalf of American Shale (see Note 7). The amount due to the operator reported at December 31, 2014 and 2013, is net of a $708,467 and $637,667 credit respectively, related to a refund of prior drilling costs previously invoiced to America Shale for wells we are not participating in as well as intercompany charges related to employee salary reimbursements, travel expenses, and lease costs.

NOTE 4 OIL AND GAS PROPERTIES

Total additions for oil and gas properties for the year ended December 31, 2014 and 2013 were $32,709,147 and $29,708,602, respectively. Depreciation, depletion, and amortization expenses on oil and gas properties were $8,499,325 and $5,664,047 for the years ended December 31, 2014 and 2013, respectively.

NOTE 5 ASSETS AND LIABILITIES HELD FOR SALE

The $14,301,375 of assets available for sale relate to the Wetzel county properties located in West Virginia including 5,159 net acres held by the Company and the Company s interest in twelve Marcellus producing wellbores which the Company has contracted to sell to TH Exploration, LLC, a Texas limited liability company. See Note 19 Subsequent Events

NOTE 6 PROPERTY AND EQUIPMENT

At December 31, 2014 and 2013, property and equipment consisted of:

	2014	2013
Vehicles	$ 140,768	$ 140,768
Machinery and equipment	84,062	114,032
Furniture and fixtures	230,759	236,475
Leasehold improvements	30,696	30,696
Land	382,951	382,951
Accumulated depreciation	(364,710)	(317,704)
Total fixed assets	$ 504,526	$ 587,218

Total additions for property, plant and equipment for the years ended December 31, 2014 and 2013 were $8,470 and $9,141, respectively. Depreciation, depletion and amortization expenses for property and equipment were $84,589 and $88,314 for the years ended December 31, 2014 and 2013, respectively.

NOTE 7 SALE OF OIL AND GAS PROPERTIES

On January 24, 2013, we closed the sale of our interests in certain non-core assets for approximately $2.6 million of net cash proceeds. The interests sold consisted of our working interest in all existing shallow wells, but we retained an overriding royalty interest of approximately 2.5% on most of the wells. The purchaser assumed the role of operator with respect to approximately 300 wellbores, and has commenced a workover program with respect to a number of the existing wells. The wells produced at a rate of approximately 800 Mcfe per day as of December 31, 2012, which was the effective date for the transaction.

Additionally, we granted the purchaser the right to drill wells in or above conventional shallow Devonian formations, for leases where we currently hold rights to such depths. We did not farm out any of our rights to drill in deeper formations such as the Rhinestreet, Marcellus or Utica. We retained up to a 5% overriding royalty interest on any such wells drilled, depending on the net revenue interest.

On December 13, 2013, the Company and Republic closed a transaction pursuant to a Purchase and Sale Agreement (the PSA) dated September 30, 2013. The Company owned 1,114.8 lease acres of the total 4,650 lease acres and leasehold working interests in certain partially completed well sites, located in Tyler County, West Virginia. At closing, the Company received cash of approximately $10.6 million of the total purchase price of $36.3 million, net of holdback. A total of 118.6 lease acres were excluded from the sale (39.8 lease acres net to the Company) due to incurable title defects. An additional 135.5 lease acres (30.7 lease acres net to the Company) were excluded from the sale due to curable title defects, which were cured and an additional $0.2 million was due and payable to the Company, as of December 31, 2013, per the terms of the PSA. In February 2014, the Company received $489,608 related to curable title defects. The proceeds were applied to a receivable of $230,064 recorded at December 31, 2013. The remaining $259,544 is reported, net of expenses, as a gain on sale of assets in 2014.

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On May 21, 2014 (Funding Date), American Shale entered into a purchase and sale agreement (the Republic PSA) with its joint venture partner, Republic Energy Ventures (Republic). Under the Republic PSA, for $15 million, American Shale sold (i) an undivided interest across all of its undeveloped leasehold amounting to approximately 2,239 net acres, (ii) an over-riding royalty interest of 1.5% in all of its leasehold in Wetzel County, West Virginia, and (iii) an over-riding royalty interest of 1.0% in six (6) wells that are currently being drilled in Marshall County, West Virginia. The consideration is to be paid in the form of a credit against expenses incurred by Republic on behalf of American Shale. American Shale reserved the right to receive 25% of the net profits earned by Republic on the assets sold. American Shale had the option to repurchase the undivided interest across all of its undeveloped leasehold, plus the over-riding royalty interest in its Wetzel County leasehold, for $15 million if (i) such payment is made within six (6) months of the Funding Date, or (ii) a purchase and sale agreement that would allow for such repayment by American Shale is signed within such period and the transaction contemplated therein is closed prior to December 31, 2014. American Shale did not exercise the option to repurchase the royalty interest and the sale is recognized as a gain on sale of assets at December 31, 2014.

As part of the Republic PSA, Republic also agreed to amend the Amended Joint Development Agreement with American Shale (the AJDA). Under the revised AJDA, Republic agreed to fund all costs associated with new leasehold acquisitions subsequent to April 1, 2014. American Shale has the right to buy a 25% interest in any such leasehold at Republic s cost, plus 12% interest, in the event that Republic sells its interest in the leasehold or permits a third party to drill a well on the leasehold. In the event that American Shale repays Republic under the terms of the Republic PSA, American Shale will have the option to fund a 50% portion of any future leasehold expenditures, upon providing satisfactory evidence of its ability to continue such funding on a go-forward basis.

On December 24, 2014, American Shale closed a transaction pursuant to a Purchase and Sale Agreement (the PSA) executed as of December 24, 2014 with Wellbore Capital, LLC, a Delaware limited liability company (Wellbore). Pursuant to the PSA, the Sellers granted to Wellbore overriding royalty interests in certain leases (the Oil and Gas Properties) located in Wetzel and Marion Counties, West Virginia (collectively, the ORRI). Under the PSA, the purchase price for the ORRI was $11.0 million, of which the Company received approximately $10.7 million in cash at closing. The PSA provides Wellbore the right to sell its interests in the ORRI to a third party acquiror in the event that Sellers sell all of their interests in the oil and gas properties to such acquiror. If such sale occurs prior to December 31, 2017, Wellbore alternatively has the right to require Sellers to repurchase the ORRI for a certain return on its investment in the ORRI.

NOTE 8 ENVIRONMENTAL SETTLEMENT AND RELATED COSTS

On September 28 and December 17, 2012, the U.S. Environmental Protection Agency (EPA) issued to the Company seven administrative compliance orders and a request for information. The orders and request relate to our compliance with Clean Water Act (CWA) permitting requirements at seven pond and/or well site locations in Marshall and Wetzel Counties, West Virginia and concern the alleged discharge of dredged and/or fill material into waters of the United States. The Company is actively cooperating with the EPA to resolve these matters in a timely manner. The CWA provides authority for significant civil and criminal penalties for the placement of fill in a jurisdictional stream or wetland without a permit from the Army Corps of Engineers. Monetary civil and/or criminal penalties can be substantial for non-compliance with CWA requirements. The CWA sets forth criteria, including degree of fault and history of prior violations, which may influence CWA penalty assessments. The EPA may also seek to recover any economic benefit derived from non-compliance with the CWA.

On August 25, 2014, Trans Energy entered into a civil Consent Decree with the EPA with respect to the CWA matter and related issues that were discovered based upon an internal audit. Fines associated with the Consent Decree amount to $3,000,000.

As part of the Consent Decree, Trans Energy is required to perform certain restoration activities at affected pond, well pad and access roads at multiple sites. We have preliminarily estimated the cost of early components of restoration over all the sites involved to be an additional $3,000,000, net to Trans Energy. Overall costs may range as high as $9,000,000. The restoration will be performed during the 2015, 2016 and 2017 construction seasons. Our estimate of costs to us will be refined, and may increase or decrease as we submit work plans to the EPA for approval to perform these restoration activities. Additionally, we are exploring avenues to offset some costs to the extent they are reimbursable through our joint venture agreements and the purchase or trading of wetland credits.

On October 1, 2014, Trans Energy, Inc. pleaded guilty to three misdemeanor charges related to Unauthorized Discharge into a Water of the United States in violation of the Clean Water Act. In connection with this plea, the Company agreed to pay a $600,000 fine and was placed on probation for a period of two years.

As a result of this plea and the previously disclosed settlement agreement, all civil and criminal matters arising out of the EPA s investigation and complaints arising out of the ponds in Marshall and Wetzel Counties West Virginia have been resolved.

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NOTE 9 PROVISION FOR TAXES

The Company s income tax (benefit) provision is as follows:

	2014	2013
Current:	$	$
Deferred:		
Change in depreciation, depletion and amortization	$ 1,437,000	$ 2,895,000
Change in unrealized gain (loss) on derivative	2,841,000	232,000
Change in other items	(17,000)	128,000
Change in NOL	(4,160,000)	(11,783,000)
Change in accruals	(1,020,000)	
Change in valuation allowance	919,000	8,528,000
Total	$	$

The income tax provision differs from the amount of income tax determined by applying the U.S. federal and state income tax rates to pretax income from continuing operations for the years ended December 31, 2014 and 2013 primarily due to the generation of NOL carryforwards, expense related to stock options, intangible drilling costs, availability of AMT credit carryforwards, unrealized gain (loss) on derivative contracts and the valuation allowance.

At December 31, 2014, Trans Energy had net operating loss carryforwards of approximately $63.6 million that may be offset against future taxable income from 2015 through 2033. No tax benefit has been reported in the December 31, 2014 and 2013 consolidated financial statements since the potential tax benefit is offset by a valuation allowance of the same amount.

Due to the change in ownership provisions of the Tax Reform Act of 1986, net operating loss carryforwards for Federal income tax reporting purposes are subject to annual limitations. Should a change in ownership occur, net operating loss carryforwards may be limited as to use in future years.

Net deferred tax assets and liabilities consist of the following components as of December 31, 2014 and 2013:

	2014	2013
Deferred tax assets:		
NOL carryover	$ 21,625,000	$ 17,465,000
AMT credit	606,000	606,000
Accruals	1,020,000	
Unrealized loss on derivative contract		43,000
Other	31,000	14,000
Total deferred tax assets	23,282,000	18,128,000
Deferred tax liabilities:		
Depreciation, depletion and amortization	(4,884,000)	(3,447,000)
Unrealized gain on derivative contract	(2,798,000)	

Total deferred tax liabilities	(7,682,000)	(3,447,000)
Valuation allowance	(15,600,000)	(14,681,000)
Net deferred taxes	$	$

NOTE 10 NOTES PAYABLE

On April 26, 2012 American Shale closed a Credit Agreement transaction (hereafter the Chambers Credit Agreement) with several banks and other financial institutions or entities that from time-to-time will be parties to the Chambers Credit Agreement (the Lenders), and Chambers Energy Management, LP as the administrative agent (Agent or Chambers).

The Chambers Credit Agreement provided that the Lenders would lend American Shale up to $50 million, which funds would be used to develop wells and properties that we transferred to American Shale. In order to accommodate the terms of the Chambers Credit Agreement Trans Energy transferred certain assets and properties to American Shale. Trans Energy and Prima were not direct parties to the Chambers Credit Agreement, but were guarantors of loans to be made there under. We received a portion of the loan proceeds to repay outstanding debts. The assets and properties transferred are referred to herein as the Marcellus Properties, which at the time of the transfer consisted of working interests in 13 gross (7.60 net) producing Marcellus shale liquids-rich gas wells and approximately 22,000 net acres of Marcellus shale leasehold rights, located in Northwestern West Virginia in the counties of Wetzel, Marshall, Marion, Tyler, and Doddridge.

The Chambers Credit Agreement was originally for a notional amount of $50 million, which was received at closing net of a $3 million Original Issue Discount (OID) and a $50,000 administrative fee due annually. These OID costs were netted against notes payable and were being amortized over the life of the loan using the straight-line method, which approximated the effective interest method. For the years ended December 31, 2014 and 2013, $1,189,400 and $794,118 of the OID was amortized as interest expense, respectively.

On February 28, 2013, American Shale, the Lenders and the Agent amended and restated the Chambers Credit Agreement in order to facilitate an increase in the principal amount of the borrowings under the facility to $75 million. The additional funds were received February 28, 2013. The other terms of the Chambers Credit Agreement were unchanged.

Interest was due monthly at 10% plus the greater of 1% or the 3 month LIBOR rate (11% at time of payoff). Principal was due at maturity, February 28, 2015. We had to pay interest through April 26, 2014, on any principal prepayments with respect to the original $50 million loan at the time of the prepayment prior to April 26, 2014. American Shale was obligated to pay a Termination Fee with respect to the $25 million loan upon the earliest to occur of (i) a Change of Control, (ii) repayment in full of the loans under the Chambers Credit Agreement and (iii) certain defaults under the Chambers Credit Agreement related to seeking relief from creditors or generally being unable to repay debts as they come due. The Termination Fee was defined as $12.5 million less all interest payments actually made with respect to the $25 million loan prior to such date.

The Company estimated its liability related to the Termination Fee to be approximately $6.8 million ($12.5 million gross fee, less $5.7 million in interest payments) (the Termination Fee Liability).

The Termination Fee Liability was recorded on the Company s condensed consolidated balance sheet as an addition to the related debt balance, offset by an equal debt discount of $6.8 million (the Termination Fee Debt Discount). The Termination Fee Debt Discount was being amortized to interest expense through the expected payment date of February 28, 2015; however, such amortization was accelerated upon payment of the Termination Fee in conjunction with the Morgan Stanley Credit Agreement. At repayment of the loan the Termination Fee was computed to be $9,077,778. For the years ended December 31, 2014 and 2013, the Company recorded $3,940,689 and $0 of amortization related to the Termination Fee, respectively.

During the year ended December 31, 2014 and 2013, the Company recorded interest expense of $1,115,280 and $0 related to the amortization of the Termination Fee Debt Discount, respectively.

The Chambers Credit Agreement included a contingent interest provision that added 1% of the outstanding principal amount of the loan to the loan balance for any quarter in which American Shale s Consolidated Leverage Ratio exceeds certain levels. American Shale s Consolidated Leverage Ratio exceeded the allowed level at September 30, 2012, and quarterly thereafter. Therefore, the contingent interest provision had been applied and $1,149,969 and

$2,030,050 was added to the principal balance and interest expense in 2014 (through the date of the repayment) and for the year ended December 31, 2013, respectively.

For the months of August, September, and October 2013, the Chambers Credit Agreement was amended to add the interest due during those months to the principal balance of the loan. In addition, $375,000 was added to the principal balance of the loan in connection with this amendment. The $375,000 was being amortized over the three month period. August, September and October 2013 interest of $2,186,038 had been added to the principal balance of the loan.

On December 20, 3013, American Shale amended the Chambers Credit Agreement to increase the principal amount of the borrowings by $7.5 million to pay a portion of the cost to purchase an outstanding warrant held by Chambers (See Note 11). The additional funds were received December 20, 2013.

On May 21, 2014, American Shale entered into a credit agreement (the Morgan Stanley Credit Agreement) by and among American Shale, several lenders (the Lenders), and Morgan Stanley Capital Group Inc. as the administrative agent (Agent). Trans Energy is a guarantor of the Morgan Stanley Credit Agreement as is Prima, another of our wholly owned subsidiaries. The Morgan Stanley Credit Agreement provides that the Lenders will lend American Shale up to $200 million, including an initial draw of $102.5 million plus a PIK fee of $593,750, a contingent committed amount of $47.5 million and an uncommitted amount of $50 million (the Loans). The initial draw under the facility was used primarily to repay all of the outstanding debt under the Chambers Credit Agreement, as well as to fund certain fees and expenses incurred in connection with the Morgan Stanley Credit Agreement.

The Loans will initially bear interest at a per annum rate equal to 9% plus the greater of 1% or LIBOR, for a three month interest period. The interest rate will be automatically lowered if American Shale improves the ratio of the value of its proved developed producing (PDP PV9) properties to its funded debt, less cash and other liquid assets, as further defined under the Morgan Stanley Credit Agreement (the Net Debt Ratio). Upon the occurrence of certain events of default, the loans will bear interest at an additional 2% per annum above the initial rate, and with respect to other events of default, may bear interest at the higher default rate. Interest will be due and payable monthly in arrears. During the year ended December 31, 2014, the Company recorded interest expense of $5,884,793 related to the Morgan Stanley Credit Agreement.

The initial loan was advanced as a single funding of $102.5 million plus a PIK fee of $593,750 on the Funding Date. Additional amounts up to $47.5 million may be drawn within the two year period after the Funding Date provided that the Net Debt Ratio, pro forma for such subsequent drawdowns, based on the level of PDP PV9 that is projected six months from the date of each drawdown, meets certain pre-defined targets. All principal will be due on December 31, 2018 (the Maturity Date), if not accelerated before that date. Scheduled amortization of the principal amount of the loans may begin on May 1, 2015, unless the Net Debt Ratio exceeds certain defined parameters, in which case scheduled amortization may begin as late as May 1, 2016. No amortization is required if American Shale s Net Debt Ratio meets certain criteria. The minimum amortization required each month will be the greater of (i) 0.75% of the then outstanding balance (after May 1, 2016) or (ii) the amortization amount that would be required for American Shale to achieve a predetermined Net Debt Ratio within six months. Such ratios increase over time.

The principal amount of the Loans may be prepaid, but not reborrowed. If the Loans are prepaid on or prior to the first anniversary of the Funding Date, a make-whole amount will be charged equal to 4.0% of the principal balance of the Loans, plus the sum of the remaining scheduled payments of interest prior to the first anniversary of the Funding Date. Up to $25 million of prepayments from specified sources will be exempt from this provision if payments are made prior to the first anniversary of the Funding Date. If the Loans are prepaid on or after the first anniversary of the Funding Date but prior to the second anniversary of the Funding Date, a make-whole amount equal to 4.0% of the principal balance of the Loans will be charged. Prepayments between the second and third anniversary of the Funding Date will be charged 3.0% of the principal balance of the Loans.

Also on the Funding Date of the Morgan Stanley Credit Agreement, Trans Energy and Prima executed a Guarantee and Security Agreement providing that Trans Energy and Prima will guarantee the indebtedness of American Shale under the terms of the Morgan Stanley Credit Agreement.

The Morgan Stanley Credit Agreement includes certain customary affirmative covenants such as minimum hedging requirements, delivery of financial information, operation and maintenance of properties, and maintenance of books and records. Financial covenants include a maximum leverage ratio (latest twelve months EBITDA to net debt) and minimum current ratio (consolidated current assets to consolidated current liabilities). The definition of net debt includes funded debt plus accounts payable, offset by cash as well as accounts receivable. American Shale is also required to apply toward approved capital expenditures a minimum of 50% of the proceeds of any equity issuance that occurs subsequent to the first anniversary of the Funding Date.

Negative covenants include limitations on indebtedness, liens, fundamental changes, dispositions of property, payment of dividends or distributions, capital expenditures, investments and transactions with affiliates. There are also limitations on hedging transactions, creation or acquisition of subsidiaries, use of proceeds, drilling without providing title opinions, amending certain documents and appointing non-approved officers or directors.

Upon the occurrence of a change of control (as defined in the Morgan Stanley Credit Agreement), the Lenders may require American Shale to pay all of the outstanding interest, make-wholes and fees in addition to 101% of the principal amounts of the Loans under the Morgan Stanley Credit Agreement.

On the Funding Date, American Shale also entered into a Net Profits Interest Agreement (the NPI Agreement) with the Agent. The NPI Agreement provides that subsequent to the repayment of the Loans, American Shale will pay a net profits interest to the Agent (the NPI). The NPI is to be calculated based on production revenues less certain expenditures, including operating costs, general and administrative expenses, interest and capital expenditures. The amount of interest expense and general and administrative expenses that can be charged are limited based on the amounts that were previously expensed prior to repayment of the Loans. The NPI is earned based on amounts borrowed under the Morgan Stanley Credit Agreement. As of the Funding Date, a NPI of 6.5% of the net profits, as defined under the NPI Agreement, has been earned. The Agent will earn up to an additional 2.5% of the net profits pro rata for any subsequent borrowing by American Shale under the $47.5 million contingent commitment. At June 30, 2014, the company recorded a discount related to the NPI of $3,339,376 on proved property and $733,034 on unproved property. The total value recorded as a discount on loan payable related to the NPI is $4,072,410. For the year ended December 31, 2014, the company recorded accretion of the discount related to the NPI in the amount of $518,307 which is computed using the straight line method over the life of the loan.

The NPI Agreement provides the Agent with the option to sell its NPI for fair value, as defined in the NPI Agreement, alongside American Shale or Trans Energy in the event that either American Shale or Trans Energy sells interests, including partial interests, in the subject properties at a fair value for the NPI that meets or exceeds $1.5 million for each 1.0% of NPI earned by the Agent prior to such date. In such event, American Shale can also require the Agent to sell all of its NPI to American Shale (or, alternatively, to the buyer of any subject interests) for fair value. In the event of a sale of all or substantially all of the assets of American Shale, fair value is defined as the net cash received that is attributable to the equity interests of either American Shale or Trans Energy in such transaction.

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On August 20 and October 3, 2014, American Shale made $5 million draws in accordance with the Morgan Stanley Credit Agreement.

The following table summarizes the components of total debt recorded on the Company s consolidated balance sheets as of December 31, 2014 and 2013:

	December 31, 2014 (audited)	**December 31, 2013** (audited)
Chambers Credit Agreement	$	$ 50,000,000
Unamortized Original Issuance Discount Chambers Credit Agreement		(1,235,294)
PIK Contingent Interest Expense		2,530,050
Chambers Credit Agreement-February 2013		25,000,000
Termination Fee Chambers Credit Agreement		6,784,626
Termination Fee Debt Discount Chambers Credit Agreement		(3,940,659)
PIK Interest Fee-Chambers Credit Agreement		375,000
PIK Interest Chambers Credit Agreement		2,186,037
Chambers Credit Agreement -December 2013		7,500,000
Other loans related party		205,314
Other loans vehicles	4,402	19,239
Morgan Stanley Credit Agreement Morgan Stanley Tranche A and B	112,500,000	
Morgan Stanley Credit Agreement Morgan Stanley PIK Fee	593,750	
Morgan Stanley Credit Agreement Morgan Stanley NPI	(3,554,103)	
Total debt	$ 109,544,049	$ 89,424,313

The debt balances under the Credit Agreements are presented as a long-term liabilities on the Company s balance sheet as of December 31, 2014 and 2013. As of September 30, 2014, the Company previously presented the debt balance as current due to an uncertainty of whether the Agent of the Credit Agreement believed the Company was in technical default of the current ratio covenant (greater than 1:1) thereunder due to the deferred gain liability recorded as of such date. Although non-cash in nature, the deferred gain recorded as a current liability as of September 30, 2014 resulted in a less than 1:1 current ratio and was not explicitly excluded from the covenant calculation within the Credit Agreement. The Company has also confirmed that the Credit Agreement provides for the inclusion of the $47.5 million contingent committed tranche as a current asset when calculating the current ratio defined therein, provided that the Company is not in violation of any other covenants. As such the Company is not in default under the Credit Agreement as of September 30, 2014 or December 31, 2014. The deferred gain proceeds were reclassified to a gain on sale in December 2014 due to the expiration of the Company s repurchase option under the Republic PSA. As of December 31, 2014, the Company s current ratio exceeds 1:1 and, thus, is not in default under the Credit Agreement.

NOTE 11 DERIVATIVE AND HEDGING FINANCIAL INSTRUMENTS

On May 9, 2013, American Shale, entered into costless collars (BP Hedge) covering approximately 85% of its expected natural gas production from wells that were considered proved developed producing (PDP) as of that date. Neither oil nor natural gas liquids have been hedged, but the BTU associated with our ethane production was essentially hedged, since it is sold as part of the natural gas stream. The costless collars consist of long put options (floor) with a strike price of $4.00 per MMBtu and offsetting short calls (ceiling) with a strike price of $4.28 per MMBtu. The aforementioned volumes are hedged beginning with the June 2013 contract and ending with the April 2015 contract. A total of 3.4 MMBtu are hedged over this period, with monthly volumes declining from a high of approximately 207,000 MMBtu in June 2013 to 113,000 MMBtu in April 2015. The fair value of these commodity contracts was $410,389 and $(125,773) at December 31, 2014 and 2013, respectively.

On May 21, 2014 American Shale, entered into fixed price hedges (Morgan Stanley Fixed I), which, when combined with existing hedges, covered approximately 90% of its expected natural gas production from PDP wells as of that date. Neither oil nor natural gas liquids have been hedged, but the BTU associated with our ethane production was essentially hedged, since it is sold as part of the natural gas stream. The hedges consist of swaps with strike prices ranging between $4.38 per MMBtu to $4.06 per MMBtu. The hedges begin with the June 2014 contract and end with the December 2018 contract. A total of 13,932,171 MMBtu are hedged over this period, with monthly volumes declining from a high of 444,534 MMBtu in July 2014 to 171,940 MMBtu in November 2018. The fair value of these commodity contracts was $5,878,302 at December 31, 2014.

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On August 20, 2014 American Shale, entered into fixed price hedges (Morgan Stanley Fixed II), which, when combined with existing hedges, covered approximately 90% of its expected natural gas production from PDP wells as of that date. Neither oil nor natural gas liquids have been hedged, but the BTU associated with our ethane production was essentially hedged, since it is sold as part of the natural gas stream. The hedges consist of swaps with a fixed strike price of $3.92 per MMBtu. The hedges begin with the September 2014 contract and end with the December 2018 contract. A total of 10,499,038 MMBtu are hedged over this period, with monthly volumes declining from a high of 326,700 MMBtu in January 2015 to 33,200 MMBtu in October 2018. The fair value of these commodity contracts was $1,941,465 at December 31, 2014.

On December 23, 2014 American Shale, entered into Basis Swap fixed price hedges (Morgan Stanley Fixed III) covering approximately 50% of its expected natural gas production from PDP wells as of December 23, 2014. Neither oil nor natural gas liquids have been hedged, but the BTU associated with our ethane production was essentially hedged, since it is sold as part of the natural gas stream. The hedges consist of swaps with a fixed strike price of $(1.12) per MMBtu. The hedges begin with the December 2014 contract and end with the December 2018 contract. A total of 7,301,209 MMBtu are hedged over this period, with monthly volumes declining from a high of 266,891 MMBtu in December 2014 to 104,084 MMBtu in October 2018. The fair value of these commodity contracts was $(716,488) at December 31, 2014.

The Company has a master netting agreement on the gas hedge and therefore the current asset and liability are netted on the condensed consolidated balance sheet and the non-current asset and liability are netted on the condensed consolidated balance sheet.

The use of derivative transactions involves the risk that the counterparties will be unable to meet the financial terms of such transactions. The Company has netting arrangements with BP Energy Company that provide for offsetting payables against receivables from separate derivative instruments.

The following tables summarize the approximate volumes and average contract prices of contracts the Company had in place for gas collars and gas hedges as of December 31, 2014:

Contract Period of BP Hedge	Volumes (MMBtu)	Weighted-Average Floor Price (per MMBtu)	Weighted-Average Ceiling Price (per MMBtu)
2015	345,523	$ 4.00	$ 4.28
All gas collars*	345,523		

* Gas collars are comprised of IF Henry Hub (100%).

Contract Period Of Morgan Stanley Fixed I	Volumes (MMBtu)	Weighted-Average Fixed Price (per MMBtu)

2015	3,578,155	$	4.11
2016	3,002,489	$	4.06
2017	2,495,153	$	4.16
2018	1,995,696	$	4.29
All gas hedges*	11,071,493		

* Gas hedges are comprised of IF Henry Hub (100%).

Contract Period Of Morgan Stanley Fixed II	Volumes (MMBtu)	Weighted-Average Fixed Price (per MMBtu)	
2015	2,038,628	$	3.92
2016	1,067,313	$	3.92
2017	753,034	$	3.92
2018	546,949	$	3.92
All gas hedges*	4,405,924		

* Gas hedges are comprised of IF Henry Hub (100%).

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Contract Period Of Morgan Stanley Fixed III	Volumes (MMBtu)	Basis Swap Fixed Price (per MMBtu)	
2015	2,553,454	$	(1.12)
2016	1,878,290	$	(1.12)
2017	1,539,998	$	(1.12)
2018	1,329,467	$	(1.12)
All gas hedges*	7,301,209		

* Gas hedges are comprised of IF Henry Hub (100%).

As a part of the Chambers Credit Agreement, we entered into a warrant agreement with Chambers which required American Shale to sell the Lenders for a total of $2 million a warrant for 19,500 shares representing 19.5% of American Shale s stock at $263.44 per share. The warrant would have contractually expired on February 28, 2015. The warrant included a put option whereby the Lenders could require American Shale to repurchase the warrant as of February 28, 2015, or earlier if certain events occur. Under the put option, American Shale would pay the excess of the fair value per share of the stock over $263.44 times the number of shares exercisable less any distributions or similar payments defined by the agreement. In certain circumstances, American Shale had the option to transfer working interest in all of its wells equal to the value of the put option instead of paying in cash. As a result of the contingent put, the warrant was accounted for as a liability with changes in its fair value reported in earnings.

On December 20, 2013, American Shale entered into an agreement with the holders of the warrants whereby American Shale agreed to purchase the warrants from the holders for $9 million. The proceeds from the increased borrowings under the Chambers Credit Agreement were used to partially fund the purchase of the warrants from the holders.

The following tables detail the fair value of derivatives recorded in the accompanying balance sheets, by category:

	As of December 31, 2014			
	Derivative Assets		**Derivative Liabilities**	
	Balance Sheet Classification	**Fair Value**	**Balance Sheet Classification**	**Fair Value**
Commodity derivative	Current assets	$ 5,420,309	Current liabilities	$
Commodity derivative	Noncurrent assets	2,809,847	Noncurrent liabilities	716,488
		$ 8,230,156		$ 716,488

	As of December 31, 2013			
	Derivative Assets		**Derivative Liabilities**	
	Balance Sheet Classification	**Fair Value**	**Balance Sheet Classification**	**Fair Value**

Commodity derivative	Current assets	$	Current liabilities	$ 58,176
Commodity derivative	Noncurrent assets		Noncurrent liabilities	67,597
		$		$ 125,773

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The table below summarizes the realized and unrealized gains and losses related to our derivative instruments for the years ended December 31, 2014 and 2013.

	Twelve Months Ended December 31,	
	2014	**2013**
Realized gains on commodity derivative	$ 949,094	$ 432,158
Change in fair value of commodity derivative	7,639,441	(125,773)
Change in fair value of warrant derivative		808,278
Realized loss on warrant derivative		(7,000,000)
Total realized and unrealized gains/(losses) recorded	$ 8,588,535	$ (5,885,337)

These realized and unrealized gains and losses are recorded in the accompanying consolidated statements of operations as derivative gains (losses).

NOTE 12 FAIR VALUE MEASUREMENTS

The authoritative guidance establishes a hierarchy for inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. Observable inputs are inputs that market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the Company. Unobservable inputs are inputs that reflect the Company s assumptions of what market participants would use in pricing the asset or liability developed based on the best information available in the circumstances. The hierarchy is broken down into three levels based on the reliability of the inputs as follows:

Level 1: Quoted prices are available in active markets for identical assets or liabilities;

Level 2: Quoted prices in active markets for similar assets and liabilities that are observable for the asset or liability; or

Level 3: Unobservable pricing inputs that are generally less observable from objective sources, such as discounted cash flows models or valuations.

The financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. The Company s policy is to recognize transfers in and/or out of fair value hierarchy as of the end of the reporting period for which the event or change in circumstances caused the transfer. The valuation policies are determined by the principal financial officer and are approved by the President. Fair value measurements are discussed with the Company s audit committee, as deemed appropriate. Each quarter, the inputs used in the fair value calculations are updated and management reviews the changes from period to period for reasonableness. The Company has consistently applied the valuation techniques discussed below in all periods presented.

The following table presents the Company s financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2014 and December 31, 2013, respectively by level within the fair value hierarchy

	Level 1	Level 2	Level 3	Total
December 31, 2014				
ASSETS:				
Commodity contracts		$ 8,230,156		$ 8,230,156
LIABILITIES:				
Commodity contracts		$ 716,488		$ 716,488
December 31, 2013				
ASSETS:				
Commodity contracts				
LIABILITIES:				
Commodity contracts		$ 125,773		$ 125,773

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We use Level 2 inputs to measure the fair value of gas commodity collar derivatives. Level 2 assets consist of commodity derivative assets and liabilities (See Note 11 Derivative and Hedging Financial Instruments). The fair value of the commodity derivative assets and liabilities are estimated by the Company using income valuation techniques utilizing the income approach and an option pricing model, which take into account notional quantities, market volatility, market prices, contract parameters, counterparty credit risk and discount rates based on published LIBOR rates. The Company validates the data provided by third parties by understanding the pricing models used, obtaining market values from other pricing sources, analyzing pricing data in certain situations and confirming that those securities trade in active markets. Assumed credit risk adjustments, based on published credit ratings, public bond yield spreads and credit default swap spreads, are applied to the Company s commodity derivatives.

As of December 31, 2012, the Company s warrant derivative financial instrument issued as a part of the Chambers Credit Agreement is comprised of the warrants issued by the Company to purchase 19,500 shares of common stock with a put option (See Note 11 Derivative and Hedging Financial Instruments). The warrants were valued by third parties using a binomial lattice-based valuation model and were classified as Level 3 in the fair value hierarchy. The lattice-based valuation technique is utilized because it embodies all of the requisite assumptions (including the underlying price, exercise price, term, volatility, and risk-free interest-rate) that were necessary to measure the fair value of these instruments. The Company uses data from its peers as well as from external sources in the determination of the volatility and risk free interest rates used in the fair value calculations. A sensitivity analysis is performed as well to determine the impact of the inputs on the ending fair value estimate. Estimating fair values of derivative financial instruments requires the development of significant and subjective estimates that may, and are likely to, change over the duration of the instrument due to both internal and external market factors. In addition, option-based techniques are highly sensitive to volatility assumptions. An increase in the volatility would cause an increase in the fair value of the warrants. Likewise, a decrease in the volatility would cause a decrease in the value of the Warrants.

The significant assumptions used in the valuation of the warrant derivative liability as of December 31, 2012 were as follows:

Exercise price	$1.63 per share
Stock price	$2.89 per share
Volatility	75%
Remaining Term of Warrants	1.41 years
Risk-free interest rate	0.20%

The following table sets forth a reconciliation of changes in the fair value of financial liabilities classified as Level 3 in the fair value hierarchy:

	For the Twelve Months Ended December 31, 2014	For the Twelve Months Ended December 31, 2013
Balance as of beginning of period	$	$ (2,808,278)
Total unrealized gains (losses) included in earnings		(6,191,722)
Issuances		
Settlements		9,000,000
Transfers in and out of Level 3		

Balance as of December 31	$	$
Change in unrealized gains (losses) included in earnings		
relating to instruments still held as of December 31,	$	$

NOTE 13 STOCKHOLDERS EQUITY

In December 2014, we issued 142,857 shares of common stock to Mark D. Woodburn, a related party, for the exercise of options at a price of $0.80 per share.

In August 2014, Trans Energy issued 400,000 shares of common stock to William F. Woodburn, a related party, for the exercise of options at a price of $0.65 per share.

In August 2014, Trans Energy issued 190,000 shares of common stock to Loren E. Bagley, a related party, for the exercise of options at a price of $0.65 per share.

In August 2014, Trans Energy issued 75,000 shares of common stock to Mark D. Woodburn, a related party, for the exercise of options at a price of $0.65 per share.

In August 2014, Trans Energy issued 10,000 shares of common stock to Brett Greene, a related party, for the exercise of options at a price of $0.65 per share.

In August 2014, Trans Energy issued 20,998 shares of common stock to Jordan Corp, a related party, for the exercise of options at a price of $0.65 per share.

In August 2014, Trans Energy issued 62,963 shares of common stock to John G. Corp, a related party, for the exercise of options at a price of $0.65 per share.

In April 2014, we granted 21,000 shares of stock to three employees under the long-term incentive bonus program. The 21,000 shares are not performance based and vest semi-annually over a three year period. The 21,000 shares were valued at $3.80 per share of common stock using the fair value of the common stock at the date of grant and the fair value will be amortized to compensation expense semi-annually over three years.

In April 2014, we also granted 252,000 common stock options to six employees and five outside board members. These options vest semi-annually over three years and have a five year term. These stock options were granted at an exercise price of $3.80 per common share and the fair value was determined using the Black Scholes option pricing model. The options are being amortized to share-based compensation expense semi-annually over the vesting period.

In January 2014, Trans Energy issued 25,000 shares of common stock to Jonathan J. Corp, a related party, for the exercise of options at a price of $0.65 per share.

In January 2014, Trans Energy issued 138,331 shares of common stock to Clarence E. Smith, a 5% Beneficial owner, for the exercise of options at a price of $1.50 per share.

In December 2013, Trans Energy granted 9,000 shares of common stock to eleven employees. These shares vest immediately and the shares were valued using the fair market value of the common stock at the date of grant. During 2013, we recorded $25,650 of share-based compensation expense related to these shares.

In November 2013, Trans Energy issued 37,500 shares of common stock to Opco related to their settlement agreement.

In February 2013, we granted 42,000 shares of stock to five employees under the long-term incentive bonus program. Of the 42,000 shares, 36,000 shares are not performance based and vest semi-annually over a three year period and 6,000 shares are performance based and vest semi-annually over a three year period, subject to ongoing employment. The 42,000 shares were valued at $2.50 per share of common stock using the fair value of the common stock at the date of grant and the fair value will be amortized to compensation expense semi-annually over three years.

In February 2013, we also granted 346,000 common stock options to seven employees and five outside board members. These options vest semi-annually over three years and have a five year term. These stock options were granted at an exercise price of $2.50 per common share and the fair value was determined using the Black Scholes option pricing model. The options are being amortized to share-based compensation expense semi-annually over the vesting period. Of the 346,000 options granted, 12,000 of the options are performance based.

In May 2013, we also granted 100,000 common stock options to an outside board member. These options vest semi-annually over three years and have a five year term. These stock options were granted at an exercise price of $3.00 per common share and the fair value was determined using the Black Scholes option pricing model. The options are being amortized to share-based compensation expense semi-annually over the vesting period.

The Company has computed the fair value of all options granted using the Black-Scholes option pricing model. In order to calculate the fair value of the options, certain assumptions are made regarding components of the model, including the estimated fair value of the underlying common stock, risk-free interest rate, volatility, expected dividend yield and expected option life. Changes to the assumptions could cause significant adjustments to valuation. The Company estimated a volatility factor utilizing a weighted average of comparable published volatilities of peer companies. The Company has estimated a forfeiture rate of zero as the effect of forfeitures has not been significant and the small number of option holders does not provide a reasonable basis for prediction. The Company estimates the expected term based on the average of the vesting term and the contractual term of the options. The risk- free interest rate is based on the U.S. Treasury yield in effect at the time of the grant for treasury securities of similar maturity. The fair value of all options granted during the years ended December 31, 2014 and 2013 was determined using the following assumptions:

Expected volatility	70%	90%
Risk free interest rate	0.80%	1.75%
Expected term (years)	3.0	5.0
Dividend yield	0%	

As a result of the above stock and option transactions, we recorded total stock-based compensation of $959,823 and $1,241,701 for the years ended December 31, 2014 and 2013, respectively.

Stock option activity is as follows:

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Aggregate Fair Value
Outstanding December 31, 2012	3,640,324	$ 1.76	2.69 Years	$ 6,406,970
Granted	446,000	$ 2.61		
Exercised	(30,500)	$ 2.67		
Forfeited	(10,500)	$ 2.35		
Expired				
Outstanding December 31, 2013	4,045,324	$ 1.85	2.05 Years	$ 7,483,849
Granted	252,000	$ 3.80		
Exercised	(1,138,331)	$ 0.78		
Forfeited	(14,000)	$ 2.43		
Expired				
Outstanding December 31, 2014	3,144,993	$ 2.39	1.48 Years	$ 7,516,533
Exercisable at, December 31, 2014	2,829,329	$ 2.29		$ 6,479,163
Unvested at December 31, 2014	315,664			

NOTE 14 EARNINGS PER SHARE

Basic net income (loss) per share is computed by dividing net income (loss) by the weighted-average number of common shares outstanding during the reporting period. The shares of restricted common stock granted to certain officers and employees of the Company are included in the computation of basic net income (loss) per share only after the shares become fully vested. Diluted net income (loss) per share of common stock includes both vested and unvested shares of restricted stock. Diluted net income (loss) per common share of stock is computed by dividing net income by the diluted weighted-average common shares outstanding. When a loss from continuing operations exists, all potentially dilutive securities are anti-dilutive and are therefore excluded from the computation of diluted earnings per share. As the Company had losses for the twelve month periods ended December 31, 2014 and 2013, the potentially dilutive shares were anti-dilutive and were thus not included in the net loss per share calculation.

As of December 31, 2014, potentially dilutive securities included (i) 52,500 unvested shares of restricted common stock and (ii) 3,144,993 in-the-money outstanding options.

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NOTE 15 BUSINESS SEGMENTS

Our principal operations consist of exploration and production through Trans Energy, American Shale and Prima, and pipeline transmission with Ritchie County Gathering Systems and Tyler Construction Company.

Certain financial information concerning our operations in different segments is as follows:

	For the Year Ended December 31,	Exploration and Production	Pipeline Transmission	Corporate	Total
Revenue	2014	$ 26,969,359	$ 161,975	$ 89,484	$ 27,220,818
	2013	$ 18,174,524	$ 158,937	$ 32,097	$ 18,365,558
Income (Loss) from operations	2014	11,187,962	(172)	(12,537,073)	(1,349,283)
	2013	9,302,666	70,263	(6,194,414)	3,178,515
Interest expense	2014	19,776,017		6,586	19,782,603
	2013	15,047,619			15,047,619
Depreciation, depletion,	2014	9,701,086	1,106		9,702,192
amortization and accretion	2013	5,751,781	580		5,752,361
Property and equipment	2014	32,709,147		8,470	32,717,617
acquisitions, including oil and gas properties	2013	29,698,602	10,000	9,141	29,717,743
Total assets, net of intercompany accounts:					
December 31, 2014		111,755,587	13,558		111,769,145
December 31, 2013		90,098,192	17,129		90,115,321

NOTE 16 RELATED PARTY TRANSACTIONS

In November 2013, Clarence E. Smith, a 5% Beneficial Owner, issued payment to the Company in the amount of $200,000. Mr. Smith was exercising 138,331 options at a price of $1.50 per share. On January 24, 2014, Mr. Smith s stock was issued. The Company is recognizing interest since the funds were held approximately three months before the stock was actually issued. At December 31, 2013, the $205,314 due to Mr. Smith is recorded as a note payable, related party in the current liability section of the balance sheet.

During 2013, the Company has conducted business with two companies owned by Clarence E. Smith. Work was awarded the companies after bids were sought and reviewed. The amount of payments total $141,626 and $64,000 for the year of 2014 and 2013, respectively.

NOTE 17 ECONOMIC DEPENDENCE AND MAJOR CUSTOMERS

Trans Energy, Inc. has five customers for the year ended December 31, 2014 and five customers for the year ended December 31, 2013 that represent 100% of its gross oil and gas sales. BD Oil Gathering Corporation is the major purchaser of oil and SEI Energy, LLC is the major purchaser of gas and Williams Ohio Valley Midstream, LLC is the major purchaser of NGLs of the Company.

NOTE 18 COMMITMENTS AND CONTINGENCIES

We operate exclusively in the United States, entirely in West Virginia, in the business of oil and gas acquisition, exploration, development, exploitation and production. We operate in an environment with many financial risks, including, but not limited to, the ability to acquire additional economically recoverable oil and gas reserves, the inherent risks of the search for, development of and production of oil and gas, the ability to sell oil and gas at prices which will provide attractive rates of return, the volatility and seasonality of oil and gas production and prices, and the highly competitive and, at times, seasonal nature of the industry and worldwide economic conditions. Our ability to expand our reserve base and diversify our operations is also dependent upon our ability to obtain the necessary capital through operating cash flow, borrowings or equity offerings. Various federal, state and local governmental agencies are considering, and some have adopted, laws and regulations regarding environmental protection which could adversely affect our proposed business activities. We cannot predict what effect, if any, current and future regulations may have on our results of operations.

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In October 2013 we reached a settlement with Oppenheimer & Co., Inc. which related to the amount of the fee which was earned by Opco acting as our investment banker in assisting the Company in obtaining funding with Chambers. We recorded $401,625 in financing fees related to the settlement. The settlement consisted of $300,000 in cash, and 37,500 shares of common stock valued at $101,625 ($2.71 per share) and a registration rights agreement relating to the common stock issued.

On October 1, 2014, Trans Energy, Inc. pleaded guilty to three misdemeanor charges related to Unauthorized Discharge into a Water of the United States in violation of the Clean Water Act. In connection with this plea, the Company agreed to pay a $600,000 fine and was placed on probation for a period of two years.

On August 25, 2014, we entered into a civil Consent Decree with the EPA with respect to the Clean Water Act matter and related issues that were discovered based upon an internal audit that we conducted. The Consent Decree requires us to pay a $3,000,000 civil penalty in two installments. The Consent Decree requires us to perform certain restoration activities at the affected pond, well pad and access road sites over a period of three construction seasons. The EPA has estimated that the restoration will cost as much as $13 million, but we intend to perform the work in a manner that will cause our costs to be significantly below this estimate. The Consent Decree also requires us to put in place and maintain an environmental compliance program.

In April and May 2013, our President and Chairman of the Board, respectively, entered into change of control agreements. These agreements provide that both individuals are entitled to receive a severance payment equal to twice their annual salary and 85,000 vested common shares if there is a change in control of the Company and they are terminated or demoted. There are four other Company employees who received change in control agreements in 2013 that provide them severance payments equal to their salary for six to twenty four months and one employee would receive 50,000 vested common shares upon consummation of a change in control of the Company.

Trans Energy has gas delivery commitments to Dominion Field Services for Gateway firm nomination up to 800 Dth per day with the receipt/delivery point being Meter #4395501 (ED120). We believe that we can meet the delivery commitments based on our estimated production. If, however, Trans Energy cannot meet such commitments, it will purchase natural gas at market prices to meet such commitments which will result in a gain or loss for the difference between the delivery commitment price and the price the Trans Energy is able to purchase the gas for redelivery (resale) to its customers.

NOTE 19 SUBSEQUENT EVENTS

On April 3, 2015, we and our wholly owned subsidiaries American Shale and Prima, along with Republic Energy Ventures, LLC, Republic Partners VIII, LLC, Republic Partners VI, LP, Republic Partners VII, LLC, and Republic Energy Operating, LLC (collectively, the Sellers) entered into a Purchase and Sale Agreement (the PSA), pursuant to which the Sellers agreed to sell certain interests located in Wetzel County, West Virginia, including 5,159 net acres held by the Company and the Company s interest in twelve Marcellus producing wellbores, to TH Exploration, LLC (Buyer). The Company expects to receive approximately $47.0 million at closing, net of funds used to repurchase assets that are to be included in the sale. The Company expects it will ultimately receive approximately $71.3 million in connection with the sale of its assets and the overriding royalty interests that are to be repurchased and included in the sale. The incremental funds are expected to be received upon the successful resolution of certain quiet title actions that are currently ongoing and the release of funds that will be held in escrow for a time following the closing.

The PSA contains customary representations, warranties and indemnities among the parties and the closing contemplated by the PSA is subject to the satisfaction of certain customary conditions as described therein. Additionally, the PSA provides Buyer with the opportunity to terminate the agreement and receive its deposit plus reimbursement for diligence expenses in the event that certain conditions are not met. There can be no assurance at this time that all of the conditions may be satisfied.

The sale of the Assets pursuant to the PSA is scheduled to close within approximately ninety days after the signing of the PSA and is to be effective as of October 1, 2014.

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The foregoing descriptions of the PSA and the consideration payable hereunder do not purport to be complete and are qualified in their entirety by reference to the complete text of the PSA, a copy of which will be attached as an exhibit to the Company s Form 10-Q for the period ending June 30, 2015.

On April 27, 2015, our wholly owned subsidiary, American Shale entered into a consent and agreement (the Consent and Agreement) that amended the credit agreement dated May 21, 2014 and the associated NPI agreement by and among American Shale, several other financial institutions parties thereto as lenders, and Morgan Stanley Capital Group Inc. as the administrative agent. The Consent and Agreement reduced the contingent borrowing availability under the Tranche B facility from $47.5 million to $10.0 million, and eliminated the Tranche C facility. Potential borrowings under the Tranche B facility had been contingent on American Shale s ability to meet certain levels of PV-9 value for its producing properties, and as such there was no additional availability under Tranche B as of the signing of the Consent and Agreement. There were no other changes to the terms of the Tranche A facility loans under the credit agreement. The NPI agreement was amended to set the contingent NPI percentage at approximately 2.53%.

Under the Consent and Agreement, the administrative agent also consented to the monetization of a portion of American Shale s natural gas hedges and the disposition of a portion of American Shale s working and net revenue interests in wells in Marion County, West Virginia (the Working Interests) that have been recently drilled but not completed.

On the same date, American Shale entered into an agreement with Republic Energy Operating, LLC. Under this agreement, American Shale agreed to use the proceeds from the aforementioned hedge monetization as well as the sale of the Working Interests to pay all amounts due under the March 2015 joint interest billing statement in the amount of approximately $13.8 million provided by Republic Energy Operating, LLC. American Shale reserves the option to reacquire the Working Interests pursuant to a notice of election at agreed upon prices set forth in the agreement.

NOTE 20 SUPPLEMENTARY INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves. Crude oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment.

Trans Energy retained Wright & Company, Inc., independent third-party reserve engineers, to perform an independent evaluation of proved reserves as of December 31, 2014 and 2013, respectively. Results of drilling, testing and production subsequent to the date of the estimates may justify revision of such estimates. Accordingly, reserve estimates are often different from the quantities of crude oil and natural gas that are ultimately recovered. All of Trans Energy s reserves are located in the United States.

The standardized measure of discounted future net cash flows is computed by applying the required prices of oil and gas to the estimated future production of proved oil and gas reserves, less estimated future expenditures (based on fiscal year-end cost estimates assuming continuation of existing economic conditions) to be incurred in developing and producing the proved reserves, less estimated future income tax expenses (based on fiscal year-end statutory tax rates) to be incurred on pre-tax net cash flows less tax basis of the properties and available credits, and assuming continuation of existing economic conditions. The estimated future net cash flows are then discounted using a rate of 10 percent per year to reflect the estimated timing of the future cash flows.

Capitalized Costs and Accumulated Depreciation, Depletion and Amortization

Aggregate capitalized costs relating to Trans Energy s crude oil and natural gas producing activities, including asset retirement costs and related accumulated depreciation, depletion, and amortization are as follows:

	As of December 31,	
	2014	2013
Proved oil and gas producing properties and related lease, wells and equipment	89,453,477	$ 79,358,623
Unproved Oil and Gas Properties	5,728,196	15,092,783
Accumulated Depreciation, Depletion and Amortization	(17,731,699)	(14,473,069)
Net Capitalized Costs	$ 77,449,974	$ 79,978,337

All of Trans Energy s operations are in the United States.

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Costs Incurred in Oil and Gas Activities

Costs incurred in connection with Trans Energy s crude oil and natural gas acquisition, exploration and development activities for each of the periods shown below:

	For the Year Ended December 31,	
	2014	2013
Acquisition of Properties		
Proved	$	$
Unproved	960,554	6,065,258
Exploration Costs		
Development Costs	31,748,593	23,643,344
Total Costs Incurred	$ 32,709,147	$ 29,708,602

Results of Operations for Oil and Gas Producing Activities

Aggregate results of operations, in connection with Trans Energy s crude oil and natural gas producing activities, for each of the periods shown below:

	For the Year Ended December 31,	
	2014	2013
Sales	$ 26,969,359	$ 18,174,524
Production Costs (a)	(12,982,632)	(10,136,028)
Depreciation, Depletion and Amortization	(9,701,086)	(5,751,781)
Income Tax Expense		
Total Results of Operations for Producing Activities (b)	$ 4,285,641	$ 2,286,715

(a) Production costs consist of oil and gas operations expense, production and ad valorem taxes, plus general and administrative expense supporting Trans Energy s oil and gas operations.
(b) Excludes the activities of pipeline transmission operations, corporate overhead and interest costs, gain on sale of oil and gas assets, impairment of fixed assets and related income taxes.

Estimated Quantities of Proved Oil and Gas Reserves

Trans Energy s proved oil and natural gas reserves have been estimated by independent petroleum engineers. Proved reserves are the estimated quantities that geologic 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 the quantities expected to be recovered through existing wells with existing equipment and operating methods. Due to the inherent uncertainties and the limited nature of reservoir data, such estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production of these reserves may be substantially different from the original estimate. Revisions result primarily from new information obtained from development drilling and production history; acquisitions of oil and natural gas properties; and changes in economic factors.

The following schedule sets forth the proved reserves of Trans Energy during each of the periods presented:

	As of December 31,					
	2014			2013		
	Oil (BBL)	Gas (Mcf)	NGL (BBL)	Oil (BBL)	Gas (Mcf)	NGL (BBL)
Proved Reserves:						
Beginning of the period	19,073	42,536,167	890,367	133,735	43,939,005	1,649,873
Revisions of previous estimates	397	2,579,426	124,580	(1,808)	(13,028,885)	(722,757)
Extensions and discoveries	8	40,437,710	453,816	6,267	16,916,629	63,537
Production	(2,104)	(6,273,384)	(127,530)	(1,414)	(3,783,427)	(100,284)
Purchases of minerals in place		(2,346,798)	(72,026)			
Sales of minerals in place-leaseholds				(117,707)	(1,507,155)	(2)
End of period	17,374	76,933,121	1,269,207	19,073	42,536,167	890,367
Proved Developed Reserves, End of Year	17,374	62,489,000	1,269,207	19,073	42,536,167	890,367

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Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following information is based on Trans Energy s best estimate of the required data for the Standardized Measure of Discounted Future Net Cash Flows as of December 31, 2014 and 2013 in accordance with GAAP which requires the use of a 10% discount rate. This information is not the fair market value, nor does it represent the expected present value of future cash flows of Trans Energy s proved oil and gas reserves.

	As of December 31,	
	2014	2013
Future Cash Inflows	$ 330,073,018	$ 186,892,866
Future Production Costs (a)	(142,451,499)	(71,482,928)
Future Development Costs	(7,852,451)	
Future Income Tax Expense	(37,524,303)	(23,081,988)
Future Net Cash Flows	142,244,765	92,327,950
Discounted for Estimated Timing of Cash Flows	(75,150,765)	(48,013,950)
Standardized Measure of Discounted Future Net Cash Flows	$ 67,094,000	$ 44,314,000

(a) Production costs include oil and gas operations expense, production ad valorem taxes, transportation costs and general and administrative expense supporting Trans Energy s oil and gas operations and are based on current year-end economic conditions.

SEC reporting rules require that year-end reserve calculations and future cash inflows be based on the weighted average of the first day of the month price for the previous twelve month period. The benchmark prices for 2014 used in the above table were gas $3.31 per MMBTU, oil $94.99 per BBL and natural gas liquids $41.74 per BBL. The benchmark prices used for 2013 were gas $3.67 per MMBTU, oil $96.78 per BBL and natural gas liquids $35.36 per BBL.

Summary of Changes in Standardized Measure of Discounted Future Net Cash Flow Relating to Proved Oil and Gas Reserves

Principal changes in the aggregate standardized measure of discounted future net cash flows attributable to Trans Energy s proved crude oil and natural gas reserves at year end are set forth in the table below:

	For the Year Ended December 31,	
	2014	2013
Standardized Measure, Beginning of Year	$ 44,314,000	$ 34,295,000
Oil and gas sales, net of production costs	(14,625,871)	(8,648,780)
Changes in prices and future production	(1,676,515)	2,402,924
	40,301,999	21,245,578

Extensions, discoveries and improved recovery, net of costs		
Sales of Minerals in place-leaseholds	(3,433,255)	(7,591,348)
Change in estimated future development costs	(6,553,408)	18,845,514
Previously estimated development costs incurred		
Revisions of previous quantity estimates	4,682,554	(25,123,031)
Accretion of Discount	4,431,400	3,429,500
Net change in income taxes	(7,071,933)	(365,365)
Timing and Other	6,725,029	5,824,008
Standardized Measure, End of Year	67,094,000	$ 44,314,000

In 2013, the Company had net negative revisions of 8.2 MMcf, as 5 proved undeveloped locations were removed from its estimate of reserves at December 31, 2013 due primarily to declines in natural gas pricing and changes to the Company s drilling plans with regards to horizontal drilling.