TRANS ENERGY INC
Form 10-K
July 08, 2016

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, 2015

¨ **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, 2015) was $5,945,700 (based on a price of $1.75 per share).

The number of shares outstanding of each of the issuer s classes of common stock, as of July 8, 2016, was 15,549,454 shares

Documents incorporated by reference: None

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TRANS ENERGY, INC.

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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, 2015, we own working interests in 38 wells that have been completed in the Marcellus Shale formation, including 32 horizontal proved developed producing wells, 2 horizontal proved developed nonproducing wells, and 4 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 47,091 gross acres (13,846 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 to 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 May 20, 2016, we notified Morgan Stanley Capital Group, Inc. that we determined that we were in default under numerous provisions under the First Amended Credit Agreement dated as of July 31, 2015 (the Credit Agreement) among our subsidiary American Shale Development, Inc., a Delaware corporation (Borrower), the lenders party thereto from time to time (the Lenders), and Morgan Stanley Capital Group Inc., as administrative agent for such Lenders (in such capacity, Administrative Agent). The following defaults currently exist under the Credit Agreement:

1. The Borrower has failed to maintain the Asset Coverage Ratio as set forth in Section 6.21 of the Credit Agreement since September 30, 2015;

2. The Borrower has failed to timely provide the materials required pursuant to Sections 5.06 (r), (u), and (v) for the months ended December 31, 2015, January 31, 2016, February 29, 2016 and March 31, 2016;

3. The Borrower has failed to timely effect the Tug Hill Disposition in accordance with Section 5.19;

4. The Borrower has failed to timely engage a financial advisor reasonably acceptable to Administrative Agent and to commence the related refinancing activities in accordance with Section 5.20;

5. The Borrower has failed to timely provide the annual financial statements pursuant to Section 5.06 (a) for the year ended December 31, 2015;

6. The Borrower has failed to timely provide the Reserve Report pursuant to Section 5.06 (d) for the year ended December 31, 2015;

7. The Borrower has failed to timely provide the Quarterly Report on Hedging pursuant to Section 5.06 (g) for the quarter ended September 30, 2015.

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If these defaults under the Credit Agreement are not waived or otherwise resolved within the cure periods provided, the Administrative Agent will have the right to accelerate all of the outstanding indebtedness under the Credit Facility. If the Administrative Agent were to accelerate all of the obligations outstanding under the Credit Facility, we estimate that we would be required to pay approximately $135 million to the Administrative Agent and the Lenders. The debt balance under the Credit Agreements is presented as a current liability on the Company s balance sheet as of December 31, 2015.

We are currently in discussions with the Administrative Agent and the Lenders regarding a potential restructuring of the obligations outstanding under the Credit Agreement. While we hope to close the restructuring as soon as possible, definitive documentation is subject to negotiation. Additionally, we can provide no assurances that we will be able to successfully finalize such a restructuring, that the terms of any such restructuring will be acceptable to us or the timing or closing of such a restructuring.

Effective May 1, 2016, Tyler Construction Company, Inc., a subsidiary of the Company (Assignor) entered into an assignment and bill of sale of Gas Pipeline (hereinafter, Assignment) with Diversified Gas & Oil Corp. (Assignee) whereby the Assignor assigned the pipeline, customers, sales meters and equipment to the Assignee, and the Assignee assumed the Assignor s obligation to Dominion Field Services, Inc. under a contract between them in the amount of $87,469. Additionally, at closing, the Assignee paid the Assignor the sum of $32,530.

On September 3, 2015, American Shale entered into a Deposit Account Control Agreement (DACA) with the Administrative Agent and United Bank, Inc. Currently, the settlements related to the Company s derivative and hedge financial instruments are deposited directly into depository accounts subject to the DACA. The Administrative Agent exercises control of the depository accounts subject to the DACA and has the ability to prevent disbursements from those restricted accounts to our unrestricted cash accounts.

On July 31, 2015, American Shale entered into an amendment and waiver (the ***First Amendment and Waiver***) that amended the Credit Agreement and the associated NPI agreement. Under the terms of the First Amendment and Waiver, the parties agreed to:

Increase the Applicable Margin to 12% in the event that interest is paid in cash, and 14% if paid in kind (which represented a change from the 9% Applicable Margin then currently payable in cash);

Change the Maturity Date to December 31, 2016;

Remove the Leverage Ratio covenant;

Add a covenant requiring the PV-9 of the Borrower s proved reserves to be greater than 1.5 times the net debt, with a minimum PDP component of proved reserves that increases over time;

Eliminate the make-whole premium and any other prepayment penalties related to debt paydowns;

Require the Borrower to limit its capital expenditures and other monthly expenditures to amounts agreed upon in the First Amendment and Waiver;

Require the Borrower to close the sale of assets in Wetzel County and pay down at least $30 million of debt by September 30, 2015;

Allow the Borrower to use the next $17 million of proceeds from the Wetzel County sale, plus 50% of any proceeds thereafter, primarily for expenditures in connection with an approved plan of development;

Begin a process to refinance the debt facility, or otherwise effect its paydown through a sale of assets, during the first quarter of 2016;

Defer any payment related to the NPI on the Wetzel County assets until the loans are repaid in full;

Increase the NPI on the assets remaining after the Wetzel County sale by 2%, to approximately 11%;

Pay total fees to the administrative agent of $4 million, of which $1 million was added to the loan balance upon execution of the First Amendment and Waiver. The remainder is to be added to the loan balance upon the closing of the sale of the Wetzel County assets.

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In accordance with the First Amendment and Waiver, interest of $3,917,077 for the months of July, August, and September, 2015, was added to the principal balance of the loan. In addition, $1,000,000 was added to the principal balance of the loan upon execution of the First Amendment and Waiver.

On April 27, 2015, American Shale entered into a consent and agreement (the Consent and Agreement) that amended the Credit Agreement and the associated NPI agreement. 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 April 27, 2015, 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 reserved the option to reacquire the Working Interests pursuant to a notice of election at agreed upon prices set forth in the agreement.

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 Company paid the first installment on its penalty in the amount of $1 million, plus interest, on July 20, 2015. Under an agreement with the United States and the State of West Virginia, the Company paid a second installment on its penalty in the amount of $250,000 on April 8, 2016, and a third installment in the amount of $1,750,000, plus interest, is now due on April 21, 2017. 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 Company is in the process of submitting delineation reports and restoration plans, with corresponding timelines for performing restoration activities, to the EPA for approval. 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. Finally, on December 21, 2015, the Company entered into an Administrative Agreement with the EPA Suspension and Debarment Division to resolve all matters relating to suspension, debarment, and statutory disqualification arising from the Company s Clean Water Act misdemeanor plea. The Agreement requires that the Company comply with its plea agreement and Consent Decree, establish and review with employees a Code of Business Conduct and Ethics, establish an ethics hotline, prepare semiannual compliance reports, and retain an independent monitor to certify the Company s compliance.

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Drilling Operations

Republic Partners Joint Development Agreement

During 2015 we did not drill any new wells.

We drilled 14 horizontal wells in 2014 and retained a 41% working interest in three of the wells, approximately a 34% working interest in seven of the wells, and approximately a 13% 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 14% working interest in the remaining well. In 2012, we drilled five horizontal wells and retained a 50% working interest in two of the wells, a 43% working interest in one well, and approximately a 36% working interest in the remaining two wells.

Gastar Farm Out

Of the six horizontal wells drilled in 2011, four wells were drilled through a farm out with Gastar Exploration USA, Inc. (Gastar), whereby Gastar purchased 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 development agreement.

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

Name	Net WI	Spud Date	Completion Date	Status at 12/31/15
Woodruff 1H	.41	January 2014	April 2014	Producing
Woodruff 2H	.41	February 2014	April 2014	Producing
Blackshere 200H	.34	March 2014	June 2014	Producing
Blackshere 201H	.34	March 2014	June 2014	Producing
Anderson 8H	.32	May 2014	August 2014	Producing
Anderson 9H	.32	May 2014	August 2014	Producing
Jones 3H	.14	May 2014	Est. 2016	Est. 2016
Shaver 1H	.36	July 2014	November 2014	Producing
Shaver 2H	.36	July 2014	November 2014	Producing
Sivert 1H	.37	July 2014	September 2014	Producing
Sivert 2H	.41	July 2014	September 2014	Producing
Wright 2H	.13	September 2014	Est. 2016	Est. 2016
Wright 1H	.13	October 2014	Est. 2016	Est. 2016
Michael 1H	.10	November 2014	Est. 2016	Est. 2016
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	.14	June 2013	Est. 2016	Est. 2016
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	.48	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	Shut In

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.

For the years ended December 2015 and 2014, the majority of our natural gas was sold to SEI Energy, LLC. During 2015, the Company entered into purchase agreements with ARM Energy Management to purchase the majority of our gas sales in 2016.

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 the natural gas delivered through our pipeline 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 2015 and 2014, Sancho retained their marketing fee and remitted the 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 has renewed this enforcement initiative for 2017-2019, 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, or may be subject to additional regulatory requirements, 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. At the federal level, the 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 issued guidance regarding federal regulatory authority over hydraulic fracturing using diesel under the Safe Drinking Water Act s Underground Injection Control Program. Further, in June 2016, the EPA released a study on the effects of hydraulic fracturing on drinking water resources. The study remains subject to public comment. 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. Further the EPA recently issued rules prohibiting the discharge of waste water from onshore unconventional extraction facilities to publicly owned treatment works.

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.

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.

The EPA recently issued new rules limiting methane emissions from new or modified oil and gas sources. The rules amend the air emissions rules for the oil and natural gas sources and natural gas processing and transmission sources to include new standards for methane. Simultaneously with the methane rules, EPA adopted new rules governing the aggregating of multiple surface sites into a single-source of air quality permitting purposes. In addition, EPA had announced plans to begin work on regulations to regulate methane emissions from existing oil and gas sources. In January 2016, BLM has proposed rules governing flaring and venting on public and tribal lands, which could require additional equipment and emissions controls and well as inspection requirements.

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. As discussed above, EPA has prohibited the discharge of certain wastewater from oil and gas sources to publicly owned treatment works.

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.

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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 NSPS regulations in 2016 for reducing methane from new and modified oil and gas production sources and natural gas processing and transmission sources and the plan to propose rules for such existing sources, as discussed above.

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, 2015, we employed twelve full-time employees, consisting of four executives and managers, six marketing, lease acquisition and clerical persons, and two 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.

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 are currently in default under the Credit Agreement.

On May 20, 2016, we notified the Administrative Agent under our Credit Agreement that we were in default thereunder. If these defaults under the Credit Agreement are not waived or otherwise resolved within the cure periods provided, the Administrative Agent will have the right to accelerate all of the outstanding indebtedness under the Credit Facility. If the Administrative Agent were to accelerate all of the obligations outstanding under the Credit Facility, we estimate that we would be required to pay approximately $135 million to the Administrative Agent and the Lenders. The debt balance under the Credit Agreements is presented as a current liability on the Company s balance sheet as of December 31, 2015.

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We have a history of losses and may realize future losses

Our revenues decreased approximately 54% during the fiscal year ended December 31, 2015, primarily due to a decrease in commodity prices. 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, 2015, our net operating loss carry forward was approximately $94.0 million and our accumulated deficit was approximately $83.0 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.

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 2 to the consolidated financial statements, the Company has generated significant losses from operations and has a working capital deficit of $116,998,273 at December 31, 2015, which together raises substantial doubt about the Company s ability to continue as a going concern. Management s plans in regard to these matters are also described in Note 2. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

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

The Credit Agreement contains 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 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 an asset coverage ratio (PV-9 of proved reserves 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. Events of default have already occurred, and remain unremedied, under our Credit Agreement.

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

Our earnings are exposed to interest rate risk associated with borrowings under the Credit Agreement, which bear interest at a rate that is based on the LIBOR Currently the Company is paying a default interest rate of 17%. 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 81% of our estimated net proved reserves is natural gas, and approximately 85% of our production in 2015 was natural gas. A period of sustained low natural gas prices will have adverse effects on our results of operations and financial condition.

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;

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- 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 limited 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 is 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.

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 will 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.

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.

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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.

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. Failure to comply can also result in the issuance of orders enjoining operations. 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.

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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.

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.

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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 issued a draft study of the potential environmental impacts of hydraulic fracturing activities, but the study has not yet been finalized. A committee of the U.S. House of Representatives has conducted 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 Dodd-Frank Act 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.

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.

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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.

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.

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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.

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. Our common stock is no longer traded on the OTC Bulletin Board, it trades on the pink sheets and 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.

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Possible Penny Stock Regulation

Trading of our common stock 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.

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, 2015 and, 2014, are set forth below:

	As of December 31,							
	2015				2014			
	Oil and Condensates (BBL)	Natural Gas (Mcf)	NGL (BBL)	Mcfe	Oil and Condensates (BBL)	Natural Gas (Mcf)	NGL (BBL)	Mcfe
Developed Producing	5,457	32,129,896	1,421,576	40,692,094	9,337	44,937,000	968,283	50,802,720
Developed Non-Producing					8,037	17,552,000	300,924	19,405,766
Proved Undeveloped		5,486,768		5,486,768		14,444,121		14,444,121

Total Proved	5,457	37,616,664	1,421,576	46,178,862	17,374	76,933,121	1,269,207	84,652,607

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, 2015 and 2014 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 development 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. We plan to fund such capital expenditures with proceeds from the Credit Facility and from 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.

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As of December 31, 2015, our proved undeveloped reserves consisted of five gross locations that are drilled but not yet completed. As of December 31, 2014, our proved undeveloped reserves consisted of four gross locations.

A review of our reserves was conducted as of December 31, 2015 and 2014 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 experience in the oil & gas industry.

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, 2015 and 2014 used in the above table were as follows:

	Oil (BBL)	**Condensates** (BBL)	**Natural Gas** (MMBTU)	**NGL** (BBL)
2015	$ 50.28	$ 27.26	$ 1.43	$ 12.09
2014	$ 94.99	$ 71.61	$ 3.31	$ 41.74

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 than the SEC in 2015 and 2014. 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,			
	2015		2014	
	Oil	Natural Gas	Oil	Natural Gas
Producing Wells		32		27
Non-Producing Wells		6		11
Undrilled Well Locations				
Total Wells and Well Locations		38		38

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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,					
	2015		2014		2013	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive			12	5.13	5	2.4
Dry						
Exploratory Wells						
Productive						
Dry						
Total			12	5.13	5	2.4

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 2016, 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 2016, and are not reflected in the table above.

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 was not completed in 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 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

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, 2015 and 2014.

	Developed Acres		Undeveloped Acres		Total	
	Gross	Net	Gross	Net	Gross	Net

2015	24,390	10,014	22,700	3,832	47,090	13,846
2014	18,939	9,362	21,207	6,094	40,146	15,456

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
2016	4,474	856
2017	4,447	1,296
2018	4,892	1,001
2018	6,021	242
2020	2,249	231
2021	617	206
Total	22,700	3,832

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It is our intention to purchase assets and/or property for the purpose of enhancing our primary business operations.

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.

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. This case went to trial beginning May 9, 2016, and the jury began deliberations on May 13, 2016. On May 16, 2016, the jury ended deliberations without reaching a unanimous verdict. Accordingly, the judge declared a mistrial. While Abcouwer originally sought punitive damages in his complaint, the claims for punitive damages were not submitted to the jury for consideration. At this point it is unclear whether Abcouwer will seek a new trial in this case.

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. In addition, the Company alleges that Abcouwer made misrepresentations to Trans Energy concerning the extension of a maturity date of a credit facility with CIT Capital USA Inc. (CIT) which caused the Company damages. Trial is currently set to begin on August 22, 2016.

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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 April 21, 2015, 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 Company paid the first installment on its penalty in the amount of $1 million, plus interest, on July 20, 2015. Under an agreement with the United States and the State of West Virginia, the Company paid a second installment on its penalty in the amount of $250,000 on April 8, 2016, and a third installment in the amount of $1,750,000, plus interest, is now due on April 21, 2017. 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 Company is in the process of submitting delineation reports and restoration plans, with corresponding timelines for performing restoration activities, to EPA for approval. 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. Finally, on December 21, 2015, the Company entered into an Administrative Agreement with the EPA Suspension and Debarment Division to resolve all matters relating to suspension, debarment, and statutory disqualification arising from the Company s Clean Water Act misdemeanor plea. The Agreement requires that the Company comply with its plea agreement and Consent Decree, establish and review with employees a Code of Business Conduct and Ethics, establish an ethics hotline, prepare semiannual compliance reports, and retain an independent monitor to certify the Company s compliance.

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 was quoted on the OTC Bulletin Board under the symbol TENG until May 16, 2016 and since such time has traded on the pink sheets . 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
2015		
First Quarter	$ 3.04	$ 1.76
Second Quarter	$ 2.00	$ 1.09
Third Quarter	$ 1.75	$ 0.45
Fourth Quarter	$ 1.20	$ 0.40
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

As of June 23, 2016, there were approximately 369 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 1,500 such shareholders.

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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 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 December 2015, Trans Energy issued 25,000 shares of common stock to Gordian Group, LLC, for fees related to services rendered at a value of $0.60 per share.

In November 2015, Trans Energy issued 25,000 shares of common stock to Gordian Group, LLC, for fees related to services rendered at a value of $0.70 per share.

In October 2015, Trans Energy issued 25,000 shares of common stock to Gordian Group, LLC, for fees related to services rendered at a value of $0.80 per share.

In April 2015, Trans Energy issued 150,000 shares of common stock to Gordian Group, LLC, for fees related to services rendered at a value of $1.80 per share.

In February 2015, Trans Energy issued 100,000 shares of common stock to John G. Corp, President, for the 2014 Performance Payment at a value of $2.10 per share.

In February 2015, Trans Energy issued 100,000 shares of common stock to Stephen P. Lucado, Chairman of the Board, for the 2014 Performance Payment at a value of $2.10 per share.

In January, 2015, Trans Energy issued 109,005 shares of common stock to William F. Woodburn, a related party, for the exercise of options at a price of $1.50 per share.

In January, 2015, Trans Energy issued 109,005 shares of common stock to Loren E. Bagley, a related party, for the exercise of options at a price of $1.50 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.

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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. 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 2016 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.

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.

Results of Operations

	Fiscal Year Ended December 31,	
	2015	2014
Total revenues	12,442,028	27,220,818
Total costs and expenses	(25,457,922)	(35,472,423)
Gain (loss) on sale of assets	(12,221)	6,902,322
Loss from operations	(13,028,115)	(1,349,283)
Other expenses	(6,601,352)	(11,190,978)
Income tax expense		
Net loss	(19,629,467)	(12,540,261)

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The following table is a summary of revenues, volumes, and pricing for the twelve months ended December 31, 2015 and 2014.

Twelve Months Ended December 31, 2015 compared to the Twelve Months Ended December 31, 2014

	Twelve Months Ended December 31,		Increase/ (Decrease)	
	2015	2014		
Natural gas sales	$ 10,377,032	$ 22,119,129	$ (11,742,097)	(53.1%)
Oil sales	$ 52,215	$ 168,479	$ (116,264)	(69.0%)
Natural gas liquid sales	$ 1,832,292	$ 4,681,751	$ (2,849,459)	(60.9%)
Total Oil & Gas Sales	$ 12,261,539	$ 26,969,359	$ (14,707,820)	(54.5%)
Transportation and other revenue	$ 180,489	$ 251,459	$ (70,970)	(28.2%)
Total revenue	$ 12,442,028	$ 27,220,818	$ (14,778,790)	(54.3%)
Net Production				
Natural gas sales (Mcf)	6,505,617	6,274,237	231,380	3.7%
Oil sales (Bbls)	1,434	2,206	(772)	(35.0%)
Natural gas liquids (gallons)	8,043,999	5,356,463	2,687,536	50.2%
Natural Gas Equivalent (Mcfe)	7,663,364	7,052,683	610,681	8.7%
Average Sales Price per Unit				
Natural Gas (Mcf)	$ 1.60	$ 3.53	$ (1.93)	(54.7%)
Oil (Bbls)	$ 36.41	$ 76.37	$ (39.96)	(52.3%)
Natural gas liquids (gallons)	$ 0.23	$ 0.87	$ (0.64)	(73.6%)
Natural Gas Equivalent (Mcfe)	$ 1.60	$ 3.82	$ (2.22)	(58.1%)

Expenses

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

	Twelve Months Ended December 31,	
	2015	**2014**
Costs and Expenses of Production:		
Production Expenses	$ 10,494,539	$ 11,380,977
Production Taxes	1,114,040	1,762,696
G&A Expenses (Excluding Share-Based Compensation)	4,074,255	11,497,882
Non-Cash Shared-Based Compensation	993,149	1,128,676
Depletion of Oil and Natural Gas Properties	8,555,779	9,425,267
Impairment of Oil and Natural Gas Properties		
Depreciation and Amortization	220,102	272,088
Accretion of Discount on Asset Retirement Obligation	6,058	4,837

Costs and Expenses Per Mcfe of Production:				
Production Expenses	$	1.37	$	1.61
Production Taxes		0.15		0.25
G&A Expenses (Excluding Share-Based Compensation)		0.53		1.63
Non-Cash Shared-Based Compensation		0.13		0.16
Depletion of Oil and Natural Gas Properties		1.12		1.34
Impairment of Oil and Natural Gas Properties				
Depreciation and Amortization		0.03		0.04
Accretion of Discount on Asset Retirement Obligation				

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Total revenues of $12,422,028 for the year ended December 31, 2015 decreased $14,788,790 or 54.3% compared to $27,220,818 for the year ended December 31, 2014. The decrease in revenue is primarily due to a decrease in natural gas, oil, and natural gas liquid (NGL) prices that was only partially offset by an increase in natural gas and natural gas liquid (NGL) production volumes. During 2014 and 2013 we focused our efforts on the implementation of our drilling program in Marshall and Wetzel Counties, West Virginia. The increase in 2015 natural gas and NGL volumes resulted from bringing new wells into production.

Production costs decreased $1,535,094 or 11.7% for 2015 as compared to 2014, due to a change in estimate for ad valorem taxes in the third quarter of 2015 and lower production taxes, offset in part by higher gathering, transportation and processing fees associated with increased production in Marshall and Wetzel counties. 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 decreased $920,253 or 9.5% for 2015 as compared to 2014, primarily due to higher production volumes and lower capitalized costs in 2015.

The Company recorded no impairments of its oil and gas properties for the year ended December 31, 2015 or 2014.

Environmental settlement and related costs decreased $6,600,000 or 100% due to the settlement related to the Clean Water Act in 2014.

Selling, general and administrative expense decreased $959,154 or 15.9% for 2015 as compared to 2014, primarily due to an increase in legal and professional fees which was offset by a decrease in share based compensation for the year.

Gain on sale of assets decreased by $6,914,543 for 2015 as compared to 2014 due to the gain on sale resulting from the sale of over-riding royalty interests to Republic Energy Ventures and Wellbore Capital, LLC in 2014.

Our loss from operations was $13,028,115 for 2015 as compared to a loss of $1,349,283 for 2014. This change is primarily due to lower revenues and lower gain on sale of assets during 2015 which was offset by the Clean Water Act settlement and increased production costs in 2014.

Interest expense decreased $822,886 or 4.2% for 2015 as compared to 2014, due the Chambers loan refinancing in 2014 which was offset by a significantly higher loan balance due to Morgan Stanley as a result of additional borrowings and PIK interest. The average loan balance for 2015 and 2014 was $115,199,392 and $101,303,895 respectively.

Gain on commodity derivative increased $3,767,633 or 43.9% for 2015 as compared to 2014 primarily due to the increase in the fair value of our gas hedges, and includes the gain booked in the second quarter of 2015 related to the resetting of certain of our hedges.

Net loss of $19,629,467 for the year ended December 31, 2015 increased $7,089,206 or 56.5% compared to $12,540,261 for the year ended December 31, 2014. This increase in net loss is due primarily to a decrease in revenues and lower gain on sale of assets during 2015 which was offset by an increase in the gain on commodity derivatives.

We have accumulated approximately $94.0 million of net operating loss carryforwards as of December 31, 2015, which may be offset against future tax obligations through 2034. 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 2015 or 2014.

No tax benefit has been reported in the financial statements for the years ended December 31, 2015 or 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.

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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, 2015, we have negative working capital of $116,988,273 compared to a negative working capital of $4,211,011 at December 31, 2014. This decrease in working capital is primarily attributed to a reclassification of our notes payable to current, offset by a decrease in accrued expenses.

During 2015, net cash used in operating activities was $1,714,891 compared to net cash provided of $5,927,614 in 2014. This decrease in cash flow from operating activities is primarily due to a decrease in commodity prices and a decrease to accounts payable during 2015.

We expect our cash flow provided by operations for 2016 to increase because of higher projected commodity prices, 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 2015, net cash used for investing activities was $186,055 compared to net cash used of $13,385,539 in 2014. The reason for the change was a decrease in expenditures for oil and gas properties during 2015 compared to 2014.

During 2015, net cash provided by financing activities was $1,020,413 compared to net cash provided of $6,315,623 in 2014. This change reflects that the Company s debt decreased by a greater amount in 2014 than in 2015.

We are currently in default under our Credit Agreement and have been relying upon an informal forbearance from our lenders under that facility. See Subsequent Events below. We can give no assurance that our lenders will continue to forebear on the exercise of their remedies under the Credit Agreement. We are currently evaluating all available means to raise additional capital, including restructuring the Credit Agreement, issuing additional equity securities, and sales of a substantial part of our assets. We can give no assurance that any of these endeavors will be successful.

Inflation

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

Subsequent Events

On May 20, 2016, we notified the Administrative Agent under our Credit Agreement that we were in default thereunder. The following defaults currently exist under the Credit Agreement:

American Shale has failed to maintain the Asset Coverage Ratio as set forth in Section 6.21 of the Credit Agreement since September 30, 2015;

American Shale has failed to timely provide the materials required pursuant to Sections 5.06 (r), (u), and (v) for the months ended December 31, 2015, January 31, 2016, February 29, 2016 and March 31, 2016;

American Shale has failed to timely effect the Tug Hill Disposition in accordance with Section 5.19;

American Shale has failed to timely engage a financial advisor reasonably acceptable to Administrative Agent and to commence the related refinancing activities in accordance with Section 5.20;

American Shale has failed to timely provide the annual financial statements pursuant to Section 5.06 (a) for the year ended December 31, 2015;

American Shale has failed to timely provide the Reserve Report pursuant to Section 5.06 (d) for the year ended December 31, 2015;

American Shale has failed to timely provide the Quarterly Report on Hedging pursuant to Section 5.06 (g) for the quarter ended September 30, 2015.

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If these defaults under the Credit Agreement are not waived or otherwise resolved within the cure periods provided, the Administrative Agent will have the right to accelerate all of the outstanding indebtedness under the Credit Facility. If the Administrative Agent were to accelerate all of the obligations outstanding under the Credit Facility, we estimate that we would be required to pay approximately $135 million to the Administrative Agent and the Lenders. The debt balance under the Credit Agreements is presented as a current liability on the Company s balance sheet as of December 31, 2015.

We are currently in discussions with the Administrative Agent and the Lenders regarding a potential restructuring of the obligations outstanding under the Credit Agreement. While we hope to close the restructuring as soon as possible, definitive documentation is subject to negotiation. Additionally, we can provide no assurances that we will be able to successfully finalize such a restructuring, that the terms of any such restructuring will be acceptable to us or the timing or closing of such a restructuring.

Effective May 1, 2016, Tyler Construction Company, Inc., a subsidiary of the Company (Assignor) entered into an assignment and bill of sale of Gas Pipeline (hereinafter, Assignment) with Diversified Gas & Oil Corp. (Assignee) whereby the Assignor assigned the pipeline, customers, sales meters and equipment to the Assignee, and the Assignee assumed the Assignor s obligation to Dominion Field Services, Inc. under a contract between them in the amount of $87,469. Additionally, at closing, the Assignee paid the Assignor the sum of $32,530.

On April 3, 2015, the Company and its wholly owned subsidiaries American Shale Development, Inc. and Prima Oil Company, Inc., 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). On July 30, 2015, the Buyer elected to formally extend the expiration date of the PSA until August 14, 2015 (the Extension Period). During the Extension Period, the Buyer provided notice to the Company that the PSA would terminate on August 13, 2015. The Company believes that the PSA terminated as a result of such notice. Because of uncertainty surrounding whether the Buyer would contest the termination of the PSA along with Management s intention to sell the underlying assets as soon as such uncertainty was definitively resolved, the Wetzel county assets are being reported as assets held for sale at December 31, 2015. If those assets were reported as proved oil and gas properties for 2015, the Company would have reported additional depletion expense of $4,372,965. In January 2016, the Wetzel county assets were reclassified to proved oil and gas properties and a catch up entry for the depletion was booked by the Company. No assets were ultimately sold under this PSA.

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.

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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. The original effective date for financial statements issued by public companies was for annual reporting periods beginning after December 15, 2016. In July 2015, the FASB deferred the effective date for annual reporting periods beginning after December 15, 2017 (including interim reporting periods within those periods). Early adoption is permitted to the original effective date. 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, 2015 and 2014 and for the fiscal years ended December 31, 2015 and 2014 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.

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 Principal Executive Officer and Principal Financial Officer, to allow timely decisions regarding required disclosures.

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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, 2015, 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, 2015, our disclosure controls and procedures were ineffective due to insufficient financial reporting resources.

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 Principal Executive Officer and Principal Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2015 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, 2015 due to insufficient financial reporting resources. 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	56	President and Director	February 2005
Loren E. Bagley	74	Director	August 1991
William F. Woodburn	74	Director	August 1991
Robert L. Richards	70	Director	September 2001
Richard L. Starkey	63	Director	June 2011
Stephen P. Lucado	44	Director\Chairman of the Board\Treasurer	June 2011
Josh L. Sherman	40	Director	September 2012

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 56, 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 College (Ohio) 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 74, 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 30 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 74, 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 30 years. Prior to his involvement in the oil and gas industry, Mr. Woodburn was employed by the United States Army Corps of Engineers for 24 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 70, 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 63, 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 44, became a director on June 29, 2011, was elected Chairman of the Board on April 17, 2012, and was appointed as Treasurer of the Company on December 17, 2015. He has over 22 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 40, became a director September 4, 2012 and serves as the Chairman of the Audit and Compensation Committees. He has more than 17 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.

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, 2015, 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.

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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. In May 2015, the Company engaged Opportune LLP, a consulting firm specializing in assisting clients across the energy industry, to perform reporting functions for which the Company did not have the staff to complete in the prescribed timeframes. Josh L. Sherman, a member of our board of directors and chairman of our Audit Committee, is a partner in Opportune LLP.

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.

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 during 2015 and 2014:

Name and Principal Position	Year	Salary or Fees Paid in Cash	Bonus	Stock Awards (1)	Option Awards (2)	All Other Compensation	Total Compensation
John G. Corp (3) (4)	2015	$ 197,886	$	$ 210,000	$ 10,570	$ 15,115	$ 433,571
President	2014	$ 204,261	$ 20,000	$	$ 184,289	$ 15,370	$ 423,920
Stephen P. Lucado (5)	2015	$ 227,431	$	$ 210,000	$ 10,570	$ 14,932	$ 462,933
Treasurer	2014	$ 372,337	$	$	$ 194,951	$ 48,983	$ 616,271

(1) The amount shown in the table represents the grant date fair value of the restricted stock granted in 2015, 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 2015 and 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.
(5) All other compensation relates to reimbursed business expenses.

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.

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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).

Mr. Lucado also has a change in control termination agreement with terms substantially similar to those in Mr. Corp s agreement.

Outstanding Equity Awards at Fiscal Year-End for 2015

The following table sets forth information about outstanding equity awards held by our Named Executive Officer as of December 31, 2015:

		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)	5/26/2011	60,000		$ 2.68	6/30/2016		$
	4/26/2012	300,000		$ 2.30	6/30/2017		
	2/13/2013	83,334	16,666	$ 2.50	6/30/2018		
	12/17/2015	4,167	45,833	$ 0.60	12/17/2020		
Stephen P. Lucado (3)	5/26/2011	60,000		$ 2.68	6/30/2016		
	4/26/2012	300,000		$ 2.30	6/30/2017		
	5/02/2013	83,334	16,666	$ 3.00	6/30/2018		

12/17/2015	4,167	45,833	$ 0.60	12/17/2020

(1) The closing price of our common stock on December 31, 2015 was $0.40.
(2) The 45,833 unvested stock options granted to Mr. Corp on December 17, 2015, will vest 46% on each of June 30, 2016 and December 31, 2016.
(3) The 45,833 unvested stock options granted to Mr. Lucado on December 17, 2015, will vest 46% on each of June 30, 2016 and December 31, 2016.

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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, 2015.

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	7,500						7,500
William F. Woodburn	15,000						15,000
Robert L. Richards (3)	17,700					810	18,510
Richard L. Starkey	7,500						7,500
Josh L. Sherman	15,000						15,000

(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, 2015, Mr. Sherman held 0 of restricted common shares subject to vesting.

(2) The Amount shown in the table represents the grant date fair value of the stock options granted in 2014 and 2013, 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, 2015 included in the Form 10-K. At December 31, 2015, Messrs. Richards, Starkey, Sherman, Woodburn, and Bagley held 6,000, 6,000, 12,000, 6,000, and 6,000 common stock options, respectively, subject to vesting.

(3) Fees Earned or Paid in Cash to Mr. Richards includes reimbursed business expenses in the amount of and $810, 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, 2015, 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	2,324,311(2)	15.2%
Mark D. Woodburn	1,580,067(3)	10.4%
Clarence E. Smith	1,504,253	9.9%
Directors and Officers		
John G. Corp.*	483,163	3.2%
Robert L. Richards*	411,498(4)	2.7%
Loren E. Bagley*	2,490,251(5)	16.3%
William F. Woodburn*	2,763,391(6)	18.1%
Richard L. Starkey*	30,000	<1.0%
Stephen P. Lucado*	130,000	<1.0%
Josh L. Sherman*	30,000	<1.0%
All directors and executive officers as a group (7 persons)	6,338,303	41.5%

* Indicates director and/or executive officer at December 31, 2015.

(1) Based upon 15,261,977 shares of common stock outstanding as of December 31, 2015.

(2) Includes 1,287,500 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 334,7366 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. This case went to trial beginning

May 9, 2016, and the jury began deliberations on May 13, 2016. On May 16, 2016, the jury ended deliberations without reaching a unanimous verdict. Accordingly, the judge declared a mistrial. While Abcouwer originally sought punitive damages in his complaint, the claims for punitive damages were not submitted to the jury for consideration. At this point it is unclear whether Abcouwer will seek a new trial in this case.

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. In addition, the Company alleges that Abcouwer made misrepresentations to Trans Energy concerning the extension of a maturity date of a credit facility with CIT Capital USA Inc. (CIT) which caused the Company damages. Trial is currently set to begin on August 22, 2016.

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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	2,137,000	$ 2.53	13,000
Total	2,137,000	$ 2.53	13,000

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.

During 2015 and 2014, 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 $29,450 and $141,626 for 2015 and 2014, respectively.

During 2015 and 2014, the Company has conducted business with a company owned by William F. Woodburn. Work related to consulting services performed by Mr. Woodburn for the Company s joint venture with Republic that were billed to the Company. The amount of payments total $84,254 and $126,016 for 2015 and 2014, respectively.

In May 2015, the Company engaged Opportune LLP, a consulting firm specializing in assisting clients across the energy industry, to perform reporting functions for which the Company did not have the staff to complete in the prescribed timeframes. Josh L. Sherman, a member of our board of directors and chairman of our Audit Committee, is a partner in Opportune LLP. The amount of payments total $607,270 and $0 for 2015 and 2014 respectively.

Director Independence. Our common stock does not trade on a national stock exchange. 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 and, 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.

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Item 14 Principal Accounting Fees and Services

Audit Fees. Audit fees (including expenses) billed to the Company by Maloney + Novotny were $296,233 in fiscal year 2015 and $243,167 in fiscal year 2014. The increase fees in 2015 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.

Audit-Related Fees. Audit-related fees (including expenses) billed to the Company by Maloney + Novotny were $0 in both fiscal years 2015 and 2014.

Tax Fees. Tax fees (including expenses) billed to the Company by Maloney + Novotny were $10,001 in fiscal year 2015 and $22,109 in fiscal year 2014.

All Other Fees. All other fees billed by our auditors were $8,377 related to asset sales and the related gain to be reported as well as analysis of debt classification.

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
3.1	Articles of Incorporation (incorporated by reference to Exhibit 3.1 to the Company s Annual Report on Form 10-K for the year ended December 31, 2013, filed on May 23, 2014).
3.2	Bylaws (incorporated by reference to Exhibit 3.2 to the Company s Annual Report on Form 10-K for the year ended December 31, 2013, filed on May 23, 2014).
**10.1	Consent and Agreement dated April 27, 2015, to Credit Agreement dated May 21, 2014, by and among American Shale, several lenders, and Morgan Stanley Capital Group Inc. as the administrative agent.
**10.2	First Amendment and Waiver, dated July 31, 2015, to Credit Agreement dated May 21, 2014, by and among American Shale, several lenders, and Morgan Stanley Capital Group Inc. as the administrative agent.
**21	Subsidiaries
**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, 2015.
**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: July 8, 2016

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 John G. Corp	President and Director (Principal Executive Officer)	July 8, 2016
/s/ Stephen P. Lucado Stephen P. Lucado	Treasurer (Principal Financial Officer and Director)	July 8, 2016
/s/ Loren E. Bagley Loren E. Bagley	Director	July 8, 2016
/s/ William F. Woodburn William F. Woodburn	Director	July 8, 2016
/s/ Josh L. Sherman Josh L. Sherman	Director	July 8, 2016
/s/ Richard L. Starkey Richard L. Starkey	Director	July 8, 2016
/s/ Robert L. Richards Robert L. Richards	Director	July 8, 2016

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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, 2015 and 2014, 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, 2015 and 2014, 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.

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 2 to the consolidated financial statements, the Company has generated significant losses from operations and has a working capital deficit of $116,998,273 at December 31, 2015, which together raises substantial doubt about the Company s ability to continue as a going concern. Management s plans in regard to these matters are also described in Note 2. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

/s/ Maloney + Novotny LLC
Maloney + Novotny LLC
Cleveland, Ohio
July 8, 2016

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TRANS ENERGY, INC. AND SUBSIDIARIES

Consolidated Balance Sheets

	December 31, 2015	December 31, 2014
ASSETS		
CURRENT ASSETS		
Cash	$ 234,624	$ 1,585,530
Restricted cash	470,373	
Accounts receivable, trade	1,711,926	4,248,152
Accounts receivable, related parties	18,500	18,500
Derivative assets	3,417,887	5,420,309
Advance royalties	337,133	68,133
Prepaid expenses	642,740	767,233
Deferred financing costs, net of amortization of $2,692,690 and $599,971	3,550,184	1,051,671
Total current assets	10,383,367	13,159,528
OIL AND GAS PROPERTIES, USING SUCCESSFUL EFFORTS ACCOUNTING		
Proved properties	84,956,392	88,194,425
Unproved properties	6,829,029	5,728,196
Pipelines	4,435,421	1,259,052
Accumulated depreciation, depletion and amortization	(26,442,766)	(17,731,699)
Oil and gas properties, net	69,778,076	77,449,974
PROPERTY AND EQUIPMENT, net of accumulated depreciation of $404,669 and $364,710, respectively	426,601	504,526
OTHER ASSETS		
Assets held for sale	13,460,614	14,301,375
Derivative assets	2,423,508	2,809,847
Deferred financing costs		3,155,014
Other assets	390,925	388,881
Total other assets	16,275,047	20,655,117
TOTAL ASSETS	$ 96,863,091	$ 111,769,145

See notes to consolidated financial statements.

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TRANS ENERGY, INC. AND SUBSIDIARIES

Consolidated Balance Sheets (continued)

	December 31, 2015	December 31, 2014
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES		
Accounts payable, trade	$ 1,321,852	$ 531,761
Accounts payable due to drilling operator	548,086	5,777,983
Accounts payable, related party	1,500	1,500
Accrued expenses	1,954,257	7,429,874
Environmental settlement and related costs	2,000,000	3,600,000
Revenue payable	8,578	25,019
Commodity derivative liability	474,696	
Notes payable, current	121,062,671	4,402
Total current liabilities	127,371,640	17,370,539
LONG-TERM LIABILITIES		
Notes payable, net	2,134,018	109,539,647
Asset retirement obligations	39,669	90,928
Environmental settlement and related costs	3,000,000	3,000,000
Commodity derivative liability	1,253,024	716,488
Deferred revenue	62,510	62,510
Total long-term liabilities	6,489,221	113,409,573
Total liabilities	133,860,861	130,780,112
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; 15,263,977 and 14,578,467 shares issued, and 15,261,977 and 14,576,467 shares outstanding, respectively	15,264	14,578
Additional paid-in capital	45,965,168	44,323,190
Treasury stock, at cost, 2,000 shares	(1,950)	(1,950)
Accumulated deficit	(82,976,252)	(63,346,785)
Total stockholders equity (deficit)	(36,997,770)	(19,010,967)