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

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the Fiscal Year Ended December 31, 2014

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

For the transition period from ______ to ______

Commission File Number 0-23530

TRANS ENERGY, INC.

(Exact name of registrant as specified in its charter)

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

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

(Address of principal executive offices)

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

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

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

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No x

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

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

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

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

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

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

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

Documents incorporated by reference: None

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PART I

Item 1 Business

History

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

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

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

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

Current Business Activities

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

Recent Events

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

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

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

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

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

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

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

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

Drilling Operations

Republic Partners Joint Venture

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

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Gastar Farm Out

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

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

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

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

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Marketing

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

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

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

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

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

Competition

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

Oil and Gas Regulation

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

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

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

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

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

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

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

Surface Damage Acts

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

Environmental Regulations

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Employees

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

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

Industry Segments

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

Item 1A Risk Factors

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

We have a history of losses and may realize future losses

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Our future success will depend on the success of our exploitation, exploration, development and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions may materially affect the quantities and present value of our reserves, see below for a discussion of the uncertainties involved in these processes. Our costs of drilling, completing and operating wells are often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures could be materially and adversely affected by any factor that may curtail, delay or cancel drilling, including the following:

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

uncontrollable flows of oil, natural gas and fluids;

fires and natural disasters;

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

adverse weather conditions;

reductions in oil and natural gas prices;

oil and natural gas property title problems; and

market limitations for oil and natural gas.

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

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

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

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

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

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

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

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

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

The present value of net proved reserves included in this report should not be considered as the market value of the reserves attributable to our properties. In accordance with SEC requirements, we base the present value, discounted at 10%, of the pre-tax future net cash flows attributable to our net proved reserves on the average oil and natural gas prices during the 12-month period before the ending date of the period covered by this report determined as an un-weighted, arithmetic average of the first-day-of the-month price for each month within such period, adjusted for quality and transportation. The costs to produce the reserves remain constant at the costs prevailing on the date of the est