TENGASCO INC
Form 10-K
March 30, 2015

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

REPORT ON FORM 10-K

(Mark one)

Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year ended December 31, 2014 or

Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the transition period from __________ to __________.

Commission File No. 1-15555

TENGASCO, INC.
(name of registrant as specified in its charter)

| | |
|---|---|
| Delaware<br>(state or other jurisdiction of<br>Incorporation or organization) | 87-0267438<br>(I.R.S. Employer<br>Identification No.) |

| | |
|---|---|
| 6021 S. Syracuse Way, Suite 117, Greenwood Village, CO<br>(Address of Principal Executive Offices) | 80111<br>(Zip Code) |

Registrant's telephone number, including area code: (720) 420-4460.

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 per share.

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

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

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

Indicate by checkmark whether the registrant has submitted electronically and posted on its corporate website, 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 No

Indicate by check mark if disclosure of delinquent filers in response 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 registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

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

| | |
|---|---|
| Large Accelerated Filer o | Accelerated Filer o |
| Non-accelerated Filer o<br>(Do not check if a Smaller Reporting Company) | Smaller Reporting Company x |

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

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 was approximately $17.4 million (June 30, 2014 closing price $0.44).

The number of shares outstanding of the registrant's $.001 par value common stock as of the close of business on March 24, 2015 was 60,842,413.

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FORWARD LOOKING STATEMENTS

The information contained in this Report, in certain instances, includes forward-looking statements within the meaning of applicable securities laws. Forward-looking statements include statements regarding the Company's "expectations," "anticipations," "intentions," "beliefs," or "strategies" or any similar word or phrase regarding the future. Forward-looking statements also include statements regarding revenue margins, expenses, and earnings analysis for 2014 and thereafter; oil and gas prices; exploration activities; development expenditures; costs of regulatory compliance; environmental matters; technological developments; future products or product development; the Company's products and distribution development strategies; potential acquisitions or strategic alliances; liquidity and anticipated cash needs and availability; prospects for success of capital raising activities; prospects or the market for or price of the Company's common stock; and control of the Company. All forward-looking statements are based on information available to the Company as of the date hereof, and the Company assumes no obligation to update any such forward-looking statement. The Company's actual results could differ materially from the forward-looking statements. Among the factors that could cause results to differ materially are the factors discussed in "Risk Factors" below in Item 1A of this Report.

Projecting the effects of commodity prices, which in past years have been extremely volatile, on production and timing of development expenditures includes many factors beyond the Company's control. The future estimates of net cash flows from the Company's proved reserves and their present value are based upon various assumptions about future production levels, prices, and costs that may prove to be incorrect over time. Any significant variance from assumptions could result in the actual future net cash flows being materially different from the estimates.

GLOSSARY OF OIL AND GAS TERMS

The following are abbreviations and definitions of certain terms commonly used in the oil and gas industry and this document:

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

Bcf. One billion cubic feet of gas.

BOE. One stock tank barrel equivalent of oil, calculated by converting gas volumes to equivalent oil barrels at a ratio of 6 thousand cubic feet of gas to 1 barrel of oil.

BOPD. Barrels of oil per day.

Btu. British thermal unit. One British thermal unit is the amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Developed oil and gas reserves. Developed oil and gas reserves are reserves of any category that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

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

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

Differential. An adjustment to the price of oil or gas from an established spot market price to reflect differences in the quality and/or location of oil or gas.

Economically producible. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities. The terminal point is generally regarded as the outlet valve on the lease or field storage tank.

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

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well or a stratigraphic test well.

Farmout. An assignment of an interest in a drilling location and related acreage conditional upon the drilling of a well on that location.

Gas. Natural gas.

MBbl. One thousand barrels of oil or other liquid hydrocarbons.

MBOE. One thousand BOE.

Mcf. One thousand cubic feet of gas.

Mcfd. One thousand cubic feet of gas per day

MMcfe. One million cubic feet of gas equivalent.

MMBOE. One million BOE.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of gas.

NYMEX. New York Mercantile Exchange.

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Oil. Crude oil, condensate and natural gas liquids.

Operator. The individual or company responsible for the exploration and/or production of an oil or gas well or lease.

Play. A geographic area with hydrocarbon potential.

Polymer. The purpose of the polymer gel treatment is to reduce excessive water production and increase oil or gas production from wells that produce from water-drive reservoirs. These wells are typically produced from naturally fractured carbonate reservoirs such as dolomites and limestone in mature fields. Successful treatments are also run in certain types of sandstone reservoirs. Other practical applications of polymer gels include the treatment of waterflood injection wells to correct channeling or change the injection profile, to improve the ability of the injected fluids to sweep the producing wells in the field, making the waterflood much more efficient and allowing the operator to recover more oil in a shorter period of time.

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

The area of the reservoir considered as proved includes all of the following: (i) the area identified by drilling and limited by fluid contacts, if any; and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil and gas on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establish a lower contact with reasonable certainty.

Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

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

Proved reserve additions. The sum of additions to proved reserves from extensions, discoveries, improved recovery, acquisitions and revisions of previous estimates.

Reserves. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market and all permits and financing required to implement the project. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Reserve additions. Changes in proved reserves due to revisions of previous estimates, extensions, discoveries, improved recovery and other additions and purchases of reserves in-place.

Reserve life. A measure of the productive life of an oil and gas property or a group of properties, expressed in years.

Royalty interest. An interest in an oil and gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

Standardized measure. The present value, discounted at 10% per year, of estimated future net revenues from the production of proved reserves, computed by applying sales prices used in estimating proved oil and gas reserves to the year-end quantities of those reserves in effect as of the dates of such estimates and held constant throughout the productive life of the reserves and deducting the estimated future costs to be incurred in developing, producing and abandoning the proved reserves (computed based on year-end costs and assuming continuation of existing economic conditions). Future income taxes are calculated by applying the appropriate year-end statutory federal and state income tax rate with consideration of future tax rates already legislated, to pre-tax future net cash flows, net of the tax basis of the properties involved and utilization of available tax carryforwards related to proved oil and gas reserves.

SWD. Salt water disposal well.

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Undeveloped oil and gas reserves. Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Waterflood.  A method of secondary recovery in which water is injected into the reservoir formation to displace residual oil. The water from injection wells physically sweeps the displaced oil to adjacent production wells.

Working interest. An interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce oil and gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations.

References herein to the “Company”, “we”, “us” and “our” mean Tengasco, Inc.

# PART I

## ITEM 1.      BUSINESS.

### History of the Company

The Company was initially organized in Utah in 1916 under a name later changed to Onasco Companies, Inc.  In 1995, the Company changed its name from Onasco Companies, Inc. by merging into Tengasco, Inc., a Tennessee corporation, formed by the Company solely for this purpose.  At the Company’s Annual Meeting held on June 11, 2011, the stockholders of the Company approved an Agreement and Plan of Merger adopted by the Company’s Board of Directors which provided for the merger of the Company into a wholly-owned subsidiary formed in Delaware for the purpose of changing the Company’s state of incorporation from Tennessee to Delaware. The merger became effective on June 12, 2011 and the Company is now a Delaware corporation.

### OVERVIEW

The Company is in the business of exploration for and production of oil and natural gas.  The Company’s primary area of oil exploration and production is in Kansas.  The Company’s primary area of natural gas production had been the Swan Creek Field in Tennessee.  The Company sold all its oil and gas leases and producing assets in Tennessee on August 16, 2013.

The Company’s wholly-owned subsidiary, Tengasco Pipeline Corporation (“TPC”) owned and operated a 65-mile intrastate pipeline which it constructed to transport natural gas from the Company’s Swan Creek Field to customers in Kingsport, Tennessee.  The Company sold all its pipeline-related assets on August 16, 2013.

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The Company's wholly-owned subsidiary, Manufactured Methane Corporation ("MMC") operates treatment and delivery facilities in Church Hill, Tennessee for the extraction of methane gas from a landfill for eventual sale as natural gas and for the generation of electricity.

The Company also had a management agreement with Hoactzin Partners, L.P. ("Hoactzin") to manage Hoactzin's oil and gas properties in the Gulf of Mexico offshore Texas and Louisiana (See below, "4. Management Agreement with Hoactzin"). This management agreement expired on December 18, 2012. Peter E. Salas, the Chairman of the Board of Directors of the Company, is the controlling person of Hoactzin. He is also the sole shareholder and controlling person of Dolphin Mgmt. Services, Inc., the general partner of Dolphin Offshore Partners, L.P., which is the Company's largest shareholder.

General

1. The Kansas Properties

The Company's operated properties in Kansas are located in central Kansas and as of December 31, 2014 include 196 producing oil wells, 16 shut-in wells, and 37 active disposal wells (the "Kansas Properties"). The Company's technical management and staff have a great deal of Kansas exploration and production experience. The Company has onsite production management and field personnel working out of the Hays, Kansas office.

The leases for the Kansas Properties provide for a landowner royalty of 12.5%. Some wells are subject to an overriding royalty interest from 0.5% to 9%. The Company maintains a 100% working interest in most of its wells and undrilled acreage in Kansas. The terms for most of the Company's newer leases in Kansas are from three to five years.

During 2014, the Company drilled 9 gross wells and completed 1 well that was drilling at the end of 2013. All of these wells were operated by the Company and the Company has a working interest of 100% in each well. Of the 9 wells drilled in 2014, 4 of the wells were completed as producing wells.

All of the Company's current reserve value, production, oil and gas revenue, and future development objectives result from the Company's ongoing interest in Kansas. By using 3-D seismic evaluation on the Company's existing locations, the Company has historically added proven direct offset locations and will continue using 3-D seismic evaluation techniques in the future.

A. Kansas Ten Well Drilling Program

On September 17, 2007, the Company entered into a ten well drilling program with Hoactzin, consisting of three wildcat wells and seven developmental wells to be drilled on the Company's Kansas Properties (the "Program"). Under the terms of the Program, Hoactzin paid the Company $0.4 million for each producing well and $0.25 million for each dry hole. The terms of the Program also provided that Hoactzin would receive all the working interest in the producing wells, and would pay an initial fee to the Company of 25% of its working interest revenues net of operating expenses, referred to as a management fee. The fee paid to the Company by Hoactzin would increase to 85% of its working interest revenues net of operating expenses when net revenues received by Hoactzin reach an agreed payout point of approximately 1.35 times Hoactzin's purchase price (the "Payout Point"). The Payout Point was reached effective with production in February 2014, at which time the management fee for the Program increased from 25% to 85%.

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In 2014, the wells from the Program produced total gross production of 12.1 MBbl of which the revenues from 8.6 MBbl were net to the Company. During the 4th quarter of 2014, total gross production from these wells averaged 31 barrels per day, of which the revenues from 23 barrels per day were net to the Company.

The reserve information for the parties' respective Ten Well Program interests as of December 31, 2014 is indicated in the table below. Reserve reports are obtained annually and estimates related to those reports are updated upon receipt of the report. These calculations were made using commodity prices based on the twelve month arithmetic average of the first day of the month price for the period January through December 2014 as required by SEC regulations. The table below reflects values realized at a price of $88.34 per barrel which was used in the December 31, 2014 reserve report. In addition, the table below reflects achievement of the Payout Point and conversion of the Company's interest to an 85% interest in February 2014.

Reserve Information for Ten Well Program Interest as of December 31, 2014

| | Barrels Attributable to Party's Interest MBbl | Undiscounted Future Cash Flows Attributable to Party's Interest (in thousands) | Present Value of Future Cash Flows Discounted at 10% Attributable to Party's Interest (in thousands) |
|---|---|---|---|
| Tengasco | 117.3 | $ 6,695 | $ 2,917 |
| Hoactzin | 20.7 | $ 1,182 | $ 515 |

The Hoactzin reserves were estimated based on Tengasco reserves as of December 31, 2014.

B. Kansas Production

The Company's gross oil production in Kansas decreased by 18 MBbl from 204 MBbl in 2013 to 186 MBbl in 2014. This decrease was primarily the result of natural declines from higher 2013 production levels that had resulted from drilling and polymers performed during 2011 and the first half of 2012. Approximately 11 MBbl of the 186 MBbl in 2014 were related to production from the 5 new wells completed during 2014.

The capital projects undertaken by the Company in 2014 were initially funded by borrowings from the Company's credit facility. However, these additional borrowings under the Company's credit facility were repaid by December 31, 2014 through use of the Company's operating cash flows.

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2. The Tennessee Properties

In the early 1980's Amoco Production Company owned numerous acres of oil and gas leases in the Eastern Overthrust in the Appalachian Basin, including the area now referred to as the Swan Creek Field. In the mid-1980's, however, development of this field was cost prohibitive due to a decline in worldwide oil and gas prices and the high cost of constructing a pipeline to deliver gas to the closest market. In July 1995, the Company acquired the Swan Creek leases and began development of the field. In 2001, the Company completed construction of a 65 mile pipeline from the Swan Creek Field to several meter stations in Kingsport, Tennessee.

The Company evaluated in recent years whether continued development would add additional reserves and the likelihood of realizing additional revenues from transportation of third party gas through the Company's pipeline assets. The Company determined that current wells would be able to produce the remaining oil and gas reserves and that the Company was unable to attract any additional third party gas without substantial capital investment. As a result, the Company elected to sell its Swan Creek oil and gas assets and its pipeline assets and focus on its oil production from its Kansas Properties.

On March 1, 2013, the Company entered into an agreement with Swan Creek Partners LLC to sell all of the Company's oil and gas leases and producing assets in Tennessee as well as the Company's pipeline assets for $1.5 million. The Company closed this sale on August 16, 2013.

The associated revenues and expenses net of taxes of the Company's pipeline assets have been classified as discontinued operations in the Statements of Operations for the years ended December 31, 2012 and 2013. As the Swan Creek oil and gas assets represented only a small portion of the Company's full cost pool, the associated revenues and expenses were classified in continuing operations for the years ended December 31, 2012 and 2013.

During 2013, prior to the closing of the sale of the Tennessee oil and gas assets, the Company had 14 producing gas wells and 6 producing oil wells in the Swan Creek Field. Gross gas production volumes from the Swan Creek Field during 2013 until the sale of the properties averaged approximately 226 Mcfd compared to 216 Mcfd produced during year ended December 31, 2012. Gross oil sales volumes from the Swan Creek field during 2013 until the sale of the properties averaged approximately 16.7 BOPD compared to approximately 13.4 BOPD produced during the year ended December 31, 2012.

3. Manufactured Methane Facilities

On October 24, 2006, the Company signed a twenty-year Landfill Gas Sale and Purchase Agreement (the "Agreement") with predecessors in interest of Republic Services, Inc. ("Republic"). The Company assigned its interest in the Agreement to MMC. The Agreement provided that MMC would purchase the entire naturally produced gas stream being collected at the Carter Valley municipal solid waste landfill owned and operated by Republic in Church Hill, Tennessee and located about two miles from the Company's pipeline. The Company's pipeline was sold on August 16, 2013. The Company installed a proprietary combination of advanced gas treatment technology to extract the methane component of the purchased gas stream. The Company constructed a pipeline to deliver the extracted methane gas to the Company's then existing pipeline (the "Methane Project").

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MMC declared startup of commercial operations of the Methane Project on April 1, 2009. The total cost for the Methane Project through startup, including pipeline construction, was approximately $4.5 million.

On August 27, 2009, the Company entered into a five-year fixed price gas sales contract with Atmos Energy Marketing, LLC, ("AEM") in Houston, Texas, a nonregulated unit of Atmos Energy Corporation (NYSE: ATO) for the sale of the methane component of landfill gas produced by MMC at the Carter Valley Landfill. The agreement provided for the sale of up to 600 MMBtu per day. The contract was effective beginning with September 2009 gas production and ended July 31, 2014. The agreed contract price of over $6 per MMBtu was a premium to the then current five-year strip price for natural gas on the NYMEX futures market.

In April 2011, MMC purchased from Parkway Services Group of Lafayette, Louisiana a Caterpillar genset which was delivered in late 2011 and installed at the plant site for generation of electricity. Total cost of the generator including installation and interconnection with the power grid was approximately $1.1 million.

On January 25, 2012, MMC commenced sales of electricity generated at the Carter Valley site. The electricity generated is sold under a ten year firm price contract with Holston Electric Cooperative, Inc., the local distributor, and Tennessee Valley Authority through TVA's Generation Partners program. That program accepted generated renewable power up to 999KW; MMC's generation equipment is rated at 974 KW to maximize revenues under the favorable electricity pricing under the Generation Partners program. The price provision under this contract pays MMC the current retail price charged monthly to small commercial customers by Holston Electric Cooperative, plus a "green" premium of 3 cents per kilowatt hour (KWH). Current price paid to MMC is approximately $.129 per KWH. In December 2013, the contract was extended by agreement between the Company, Holston Electric Cooperative, and TVA for an additional ten years beginning in January 2022 at the current price rate less the three-cent "green" premium. A one-eighth royalty on electricity revenues is paid to the landfill owner.

During 2013, the Methane Project was online approximately 29% of the time resulting in gas sales net revenues net of royalty of $117,000 and the electric generation was online approximately 27% of the time resulting in electric sales net revenues of $263,000. The significant downtime during 2013 was primarily a result of consistent high levels of oxygen included in the gas coming from the landfill, causing the equipment to shut down until lower oxygen levels on a consistent basis were achieved. As result of this significant down time, the Company reconfigured the fuel supply, added some additional electric generation related equipment, and began an electric generation only program at the Carter Valley site. The cost of the reconfiguration and addition equipment was approximately $274,000 and was operational in late February 2014. During 2014, the electric generation was online approximately 56% of the time resulting in electric sales net revenues of approximately $524,000. Approximately $518,000 of the 2014 revenues were realized during the period March 2014 through December 2014 during which the electric generation was online approximately 66% of the time.

On September 17, 2007, Hoactzin, simultaneously with subscribing to participate in the Ten Well Program (the "Program"), pursuant to a separate agreement with the Company was conveyed a 75% net profits interest in the Methane Project. Because the Payout Point was reached in February 2014 as described above, Hoactzin's net profits interest in the Methane Project has decreased to 7.5%. The agreed method of calculation of net profits takes into account specific costs and expenses as well as gross gas revenues for the project. As a result of the startup costs, ongoing operating expenses, and reduced production levels discussed above, no net profits as defined have been realized during the period from the project startup in April, 2009 through December 31, 2014 for payment to Hoactzin under the net profits interest. All payments applied to reaching the Payout Point have been generated from the Program.

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4. Management Agreement with Hoactzin

On December 18, 2007, the Company entered into a Management Agreement with Hoactzin to manage on behalf of Hoactzin all of its working interest in certain oil and gas properties owned by Hoactzin and located in the onshore Texas Gulf Coast, and offshore Texas and offshore Louisiana. As part of the consideration for the Company's agreement to enter into the Management Agreement, Hoactzin granted to the Company an option to participate in up to a 15% working interest on a dollar for dollar cost basis in any new drilling or workover activities undertaken on Hoactzin's managed properties during the term of the Management Agreement. The Management Agreement expired on December 18, 2012. The Company has entered into a transition agreement with Hoactzin whereby the Company will no longer perform operations, but will administratively assist Hoactzin in becoming operator of record of these wells and administratively assist Hoactzin in the transfer of the corresponding bonds from the Company to Hoactzin. This assistance is primarily related to signing the necessary documents to effectuate this transition. Hoactzin and its controlling member are indemnifying the Company for any costs or liabilities incurred by the Company resulting from such assistance, or the fact that the Company is the operator of record on certain of these wells. As of the date of this Report, the Company continues to administratively assist Hoactzin with this transition process. The transition was anticipated to be completed by this time, and the transition agreement provides that the Company may hold Hoactzin's drilling programs funds in suspense until the transition process has been completed. As of December 31, 2014, the Company was holding approximately $590,000 of such funds pending completion of the transition process.

During the term of the Management Agreement, the Company became the operator of certain properties owned by Hoactzin. The Company obtained from IndemCo, over time, bonds in the face amount of approximately $10.7 million for the purpose of covering plugging and abandonment obligations for Hoactzin's operated properties located in federal offshore waters in favor of the BSEE, as well as certain private parties. In connection with the issuance of these bonds the Company signed a Payment and Indemnity Agreement with IndemCo whereby the Company guaranteed payment of any bonding liabilities incurred by IndemCo. Dolphin Direct Equity Partners, LP also signed the Payment and Indemnity Agreement, thereby becoming jointly and severally liable with the Company for the obligations to IndemCo. Dolphin Direct Equity Partners, L.P. is a private equity fund controlled by Peter E. Salas that has a significant economic interest in Hoactzin. Hoactzin had provided $6.6 million in cash to IndemCo as collateral for these potential obligations. As of May 15, 2014, all bonds issued by IndemCo and subject to the Payment and Indemnity Agreement have been released by the BSEE and have been cancelled by IndemCo. Accordingly, the exposure to the Company under any of the now cancelled IndemCo bonds or the indemnity agreement relating to those now cancelled bonds has decreased to zero.

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As part of the transition process, Hoactzin secured new bonds from Argonaut Insurance Company to replace the IndemCo bonds. Also as part of the transition to Hoactzin becoming operator of its own properties, right-of-use and easement ("RUE") bonds in the amount of $1.55 million were required by the regulatory process to be issued by Argonaut in the Company's name as current operator. Hoactzin is in the process of transferring these RUE bonds from the Company to Hoactzin. Hoactzin and Dolphin Direct signed an indemnity agreement with Argonaut as well as provided the required collateral for the new Argonaut bonds, including 100% cash collateral for the RUE bonds issued in the Company's name. The Company is not party to the indemnity agreement with Argonaut and has not provided any collateral for any of the Argonaut bonds issued. When the transfer of the RUE's and associated bonds is approved, the transfer of operations to Hoactzin would be complete and the Company's involvement in the Hoactzin properties will be ended.

As operator, the Company routinely contracted in its name for goods and services with vendors in connection with its operation of the Hoactzin properties. In practice, Hoactzin directly paid these invoices for goods and services that were contracted in the Company's name. During late 2009 and early 2010, Hoactzin undertook several significant operations, for which the Company contracted in the ordinary course. As a result of the operations performed in late 2009 and early 2010, Hoactzin had significant past due balances to several vendors, a portion of which were included on the Company's balance sheet. Payables related to these past due and ongoing operations remained outstanding at December 31, 2014 and 2013 in the amount of $159,000 and $327,000, respectively. The decrease in payables was due to payment by Hoactzin of invoices received by the Company from IndemCo related to bond premiums, which invoices have been paid by Hoactzin in full and the IndemCo bonds cancelled. The Company has recorded the Hoactzin-related payables and the corresponding receivable from Hoactzin as of December 31, 2014 and 2013 in its Consolidated Balance Sheets under "Accounts payable – other" and "Accounts receivable – related party". Since the second quarter of 2012, the only increase in the Hoactzin-related payables that have been recorded on the Company's Consolidated Balance Sheets relate to the IndemCo bond premiums. As all the IndemCo bonds have been cancelled, the outstanding balance of $159,000 should not increase in the future. However, Hoactzin has not made payments to reduce the $159,000 of past due balances from 2009 and 2010 since the second quarter of 2012. Based on these circumstances, the Company has elected to establish an allowance in the amount of $159,000 for the balances outstanding at December 31, 2014 and 2013. This allowance was recorded in the Company's Consolidated Balance Sheets under "Accounts receivable – related party". The resulting balances recorded in the Company's Consolidated Balance Sheets under "Accounts receivable – related party, less allowance for doubtful accounts of $159 and $257" are $0 and $168,000 at December 31, 2014 and 2013, respectively.

The Company as designated operator of the Hoactzin properties was administratively issued an "Incident of Non-Compliance" by BSEE during the quarter ended September 30, 2012 concerning one of Hoactzin's operated properties. This action calls for payment of a civil penalty of $386,000 for failure to provide, upon request, documentation to the BSEE evidencing that certain safety inspections and tests had been conducted in 2011. In the 4$^{th}$ quarter of 2012, the Company filed an administrative appeal with the Interior Board of Land Appeals ("IBLA") of this action in order to attempt to significantly reduce the civil penalty. This appeal required a fully collateralized appeal bond to postpone the payment obligation until the appeal was determined. The Company posted and collateralized this bond with RLI Insurance Company. If the bond was not posted, the appeal would have been administratively denied and the order to the Company as operator to pay the $386,000 penalty would have become final. On June 23, 2014, the IBLA affirmed the civil penalty without reduction. On September 22, 2014, the Company sought judicial review of the June 23, 2014 agency action in the federal district court in the Eastern District of Louisiana at New Orleans. While the civil penalty could ultimately be reduced in the judicial review process, as a result of the determination by the IBLA, the Company recorded a liability of $386,000 in the Company's Consolidated Balance Sheets under "Accrued and other current liabilities" and an expense in its Consolidated Statements of Operations under "Production costs and taxes" for the year ended December 31, 2014. In the event any portion of the civil penalty is affirmed, the Company expects to seek reimbursement of such penalty from Hoactzin, pursuant to the terms of the Management Agreement. However, there can be no assurances that the Company would be successful in such a claim.

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No funds have been advanced by the Company to pay any obligations of Hoactzin. No borrowing capability of the Company has been used by the Company in connection with its obligations under the Management Agreement, except for those funds used to collateralize the appeal bond with RLI Insurance Company.

5. Other Areas of Development

Although focused on development of its current Kansas holdings, the Company will continue to review potential transactions involving producing properties and undeveloped acreage in Kansas and the surrounding states.

Governmental Regulations

The Company is subject to numerous state and federal regulations, environmental and otherwise, that may have a substantial negative effect on its ability to operate at a profit. For a discussion of the risks involved as a result of such regulations, see, “Effect of Existing or Probable Governmental Regulations on Business and Costs and Effects of Compliance with Environmental Laws” hereinafter in this section.

Principal Products or Services and Markets

The principal markets for the Company’s crude oil are local refining companies. At present, crude oil produced by the Company in Kansas is sold at or near the wells to Coffeyville Resources Refining and Marketing, LLC (“Coffeyville Refining”) in Kansas City, Kansas and to National Cooperative Refinery Association (“NCRA”) in McPherson, Kansas. Both Coffeyville Refining and NCRA are solely responsible for transportation to their refineries of the oil they purchase. The Company may sell some or all of its production to one or more additional refineries in order to maximize revenues as purchases prices offered by the refineries fluctuate from time to time.

Gas from the Company’s Methane Facility has been sold at the tailgate of the plant to Atmos Energy Marketing. The contract with Atmos expired in July 2014. Electricity generated at the site is sold to Holston Electric Cooperative. The contract with Holston Electric had a ten year initial commitment and has been extended for an additional ten years as described above. The contract will expire in January 2032.

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Drilling Equipment

The Company does not currently own a drilling rig or any related drilling equipment. The Company obtains drilling services as required from time to time from various drilling contractors in Kansas.

Distribution Methods of Products or Services

Crude oil is normally delivered to refineries in Kansas by tank truck. Natural gas sold from the Company's Methane Facility has been distributed and transported by pipeline. Electricity generated at the Company's Methane Facility is distributed into the electric grid.

Competitive Business Conditions, Competitive Position in the Industry and Methods of Competition

The Company's contemplated oil and gas exploration activities in the State of Kansas will be undertaken in a highly competitive and speculative business atmosphere. In seeking any other suitable oil and gas properties for acquisition, the Company will be competing with a number of other companies, including large oil and gas companies and other independent operators with greater financial resources. Management does not believe that the Company's competitive position in the oil and gas industry will be significant as the Company currently exists.

There are numerous producers in the area of the Kansas Properties. Some of these companies are larger than the Company and have greater financial resources. These companies are in competition with the Company for lease positions in the known producing areas in which the Company currently operates, as well as other potential areas of interest.

Although management does not foresee any difficulties in procuring contracted drilling rigs, several factors, including increased competition in the area, may limit the availability of drilling rigs, rig operators and related personnel and/or equipment in the future. Such limitations would have a natural adverse impact on the profitability of the Company's operations.

The Company anticipates no difficulty in procuring well drilling permits in any state. The Company generally does not apply for a permit until it is actually ready to commence drilling operations.

The prices of the Company's products are controlled by the world oil market and the United States natural gas market. Thus, competitive pricing behaviors are considered unlikely; however, competition in the oil and gas exploration industry exists in the form of competition to acquire the most promising acreage blocks and obtaining the most favorable process for transporting the product.

Sources and Availability of Raw Materials

Excluding the development of oil and gas reserves and the production of oil and gas, the Company's operations are not dependent on the acquisition of any raw materials.

Dependence on One or a Few Major Customers

At present, crude oil from the Kansas Properties is being purchased at the well and trucked by Coffeyville Refining and NCRA, which are responsible for transportation of the crude oil purchased. The Company may sell some or all of its production to one or more additional refineries in order to maximize revenues as purchase prices offered by the refineries fluctuate from time to time.

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In 2014, no gas was produced or sold from the Methane Project. If any gas is produced from the Methane Project in the future, the Company is dependent upon a small number of customers for the sale of gas from the Methane Project. These customers are principally gas marketing companies, utility districts, and industrial customers in the Kingsport area with which the Company may enter into gas sales contracts.

Patents, Trademarks, Licenses, Franchises, Concessions, Royalty Agreements or Labor Contracts, Including Duration

On October 19, 2010, the Company's subsidiary MMC was granted United States Patent No. 7,815,713 for Landfill Gas Purification Method and System, pursuant to application filed January 10, 2007. The patent term is for twenty years from filing date plus adjustment period of 595 days due to the length of the review process resulting in grant of the patent. The patent is for the process designed and utilized by MMC at the Carter Valley landfill facility. The patent may result in a competitive advantage to MMC in seeking new projects, and in the receipt of licensing fees for other projects that may be using or wish to use the process in the future. However, the limited number of high Btu projects currently existing and operated by others, the variety of processes available for use in high Btu projects, and the effects of current gas markets and decreasing or inapplicable green energy incentives for such projects in combination cause the materiality of any licensing opportunity presented by the patent to be difficult to determine or estimate, and thus the licensing fees from the patent, if any are received, may not be material to the Company's overall results of operations.

Need For Governmental Approval of Principal Products or Services

None of the principal products offered by the Company require governmental approval, although permits are required for drilling oil or gas wells.

Effect of Existing or Probable Governmental Regulations on Business

Exploration and production activities relating to oil and gas leases are subject to numerous environmental laws, rules and regulations. The Federal Clean Water Act requires the Company to construct a fresh water containment barrier between the surface of each drilling site and the underlying water table. This involves the insertion of steel casing into each well, with cement on the outside of the casing. The Company has fully complied with this environmental regulation, the cost of which is approximately $10,000 per well.

As part of the Company's purchase of the Kansas Properties, the Company acquired a statewide permit to drill in Kansas. Applications under such permit are applied for and issued within one to two weeks prior to drilling. At the present time, the State of Kansas does not require the posting of a bond either for permitting or to insure that the Company's wells are properly plugged when abandoned. All of the wells in the Kansas Properties have all permits required and the Company believes that it is in compliance with the laws of the State of Kansas.

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The Company’s exploration, production and marketing operations are regulated extensively at the federal, state and local levels. The Company has made and will continue to make expenditures in its efforts to comply with the requirements of environmental and other regulations. Further, the oil and gas regulatory environment could change in ways that might substantially increase these costs. These regulations affect the Company’s operations and limit the quantity of hydrocarbons it may produce and sell. Other regulated matters include marketing, pricing, transportation and valuation of royalty payments. The Company’s operations are also subject to numerous and frequently changing laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. For example, in May 2014 the Company become subject to regulations under the federal Endangered Species Act relating to the protection of the lesser prairie chicken as a threatened species. To avoid stringent penalties for violation of those regulations, the Company entered into a state-operated voluntary agreement avoiding those penalties provided certain protective methods are followed in drilling operations and remediation fees are paid by the Company for any wells determined to be likely to interfere with the habitat of the threatened species. These fees may increase the Company’s costs to drill in Kansas by approximately $40,000 per well. The Company owns or leases, and has in the past owned or leased, properties that have been used for the exploration and production of oil and gas and these properties and the wastes disposed on these properties may be subject to the Comprehensive Environmental Response, Compensation and Liability Act, the Oil Pollution Act of 1990, the Resource Conservation and Recovery Act, the Federal Water Pollution Control Act and analogous state laws. Under such laws, the Company could be required to remove or remediate previously released wastes or property contamination.

Laws and regulations protecting the environment have generally become more stringent and, may in some cases, impose “strict liability” for environmental damage. Strict liability means that the Company may be held liable for damage without regard to whether it was negligent or otherwise at fault. Environmental laws and regulations may expose the Company to liability for the conduct of or conditions caused by others or for acts that were in compliance with all applicable laws at the time they were performed. Failure to comply with these laws and regulations may result in the imposition of administrative, civil and criminal penalties.

While management believes that the Company’s operations are in substantial compliance with existing requirements of governmental bodies, the Company’s ability to conduct continued operations is subject to satisfying applicable regulatory and permitting controls. The Company’s current permits and authorizations and ability to get future permits and authorizations may be susceptible, on a going forward basis, to increased scrutiny, greater complexity resulting in increased costs or delays in receiving appropriate authorizations.

The Company maintains an Environmental Response Policy and Emergency Action Response Policy Program. A plan was adopted which provides for the erection of signs at each well containing telephone numbers of the Company’s office. A list is maintained at the Company’s office and at the home of key personnel listing phone numbers for fire, police, emergency services and Company employees who will be needed to deal with emergencies.

The foregoing is only a brief summary of some of the existing environmental laws, rules and regulations to which the Company’s business operations are subject, and there are many others, the effects of which could have an adverse impact on the Company. Future legislation in this area will be enacted and revisions will be made in current laws. No assurance can be given as to the affect these present and future laws, rules and regulations will have on the Company’s current and future operations.

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Research and Development

None.

Number of Total Employees and Number of Full-Time Employees

The Company presently has 17 full time employees and no part-time employees. These employees are located in Colorado, Kansas, Tennessee, and Texas.

Available Information

The Company is a reporting company, as that term is defined under the Securities Acts, and therefore files reports, including Quarterly Reports on Form 10-Q and Annual Reports on Form 10-K such as this Report, proxy information statements and other materials with the Securities and Exchange Commission ("SEC"). You may read and copy any materials the Company files with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington D.C. 20549 upon payment of the prescribed fees. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330.

In addition, the Company is an electronic filer and files its Reports and information with the SEC through the SEC's Electronic Data Gathering, Analysis and Retrieval system ("EDGAR"). The SEC maintains a website that contains reports, proxy and information statements and other information regarding issuers that file electronically through EDGAR with the SEC, including all of the Company's filings with the SEC. These may be read and printed without charge from the SEC's website. The address of that site is www.sec.gov.

The Company's website is located at www.tengasco.com. On the home page of the website, you may access, free of charge, the Company's Annual Report on Form 10-K. Under the Investor Information /SEC filings tab you will find the Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, Section 16 filings (Form 3, 4 and 5) and any amendments to those reports as reasonably practicable after the Company electronically files such reports with the SEC. The information contained on the Company's website is not part of this Report or any other report filed with the SEC.

ITEM 1A. RISK FACTORS

In addition to the other information included in this Form 10-K, the following risk factors should be considered in evaluating the Company's business and future prospects. The risk factors described below are not exhaustive and you are encouraged to perform your own investigation with respect to the Company and its business. You should also read the other information included in this Form 10-K, including the financial statements and related notes.

The Company's indebtedness, global recessions, or disruption in the domestic and global financial markets could have an adverse effect on the Company's operating results and financial condition.

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As of December 31, 2014, the outstanding principal amount of the Company's indebtedness under its credit facility with Prosperity Bank (formerly F&M Bank & Trust Company) was approximately $734,000. Although the Company's indebtedness has been substantially reduced, the current or an increased level of indebtedness, coupled with domestic and global economic conditions, the associated volatility of energy prices, and the levels of disruption and continuing relative illiquidity in the credit markets may, if continued for an extended period, have several important and adverse consequences on the Company's business and operations. For example, any one or more of these factors could (i) make it difficult for the Company to service or refinance its existing indebtedness; (ii) increase the Company's vulnerability to additional adverse changes in economic and industry conditions; (iii) require the Company to dedicate a substantial portion or all of its cash flow from operations and proceeds of any debt or equity issuances or asset sales to pay or provide for its indebtedness; (iv) limit the Company's ability to respond to changes in our businesses and the markets in which we operate; (v) place the Company at a disadvantage to our competitors that are not as highly leveraged; or (vi) limit the Company's ability to borrow money or raise equity to fund our working capital, capital expenditures, acquisitions, debt service requirements, investments, general corporate activity or other financing needs. The Company continues to closely monitor the disruption in the global financial and credit markets, as well as the significant volatility in the market prices for oil and natural gas. As these events unfold, the Company will continue to evaluate and respond to any impact on Company operations. The Company has and will continue to adjust its drilling plans and capital expenditures as necessary. However, external financing in the capital markets may not be readily available, and without adequate capital resources, the Company's drilling and other activities may be limited and the Company's business, financial condition and results of operations may suffer. Additionally, in light of the credit markets and the volatility in pricing for oil and natural gas, the Company's ability to enter into future beneficial relationships with third parties for exploration and production activities may be limited, and as a result, may have an adverse effect on current operational strategy and related business initiatives.

Agreements Governing the Company's Indebtedness may Limit the Company's Ability to Execute Capital Spending or to Respond to Other Initiatives or Opportunities as they May Arise.

Because the availability of borrowings by the Company under the terms of the Company's amended and restated credit facility with Prosperity Bank is subject to an upper limit of the borrowing base as determined by the lender's calculated estimated future cash flows from the Company's oil and natural gas reserves, the Company expects any sharp decline in the pricing for these commodities, if continued for any extended period, would very likely result in a reduction in the Company's borrowing base. A reduction in the Company's borrowing base could be significant and as a result, would not only reduce the capital available to the Company but may also require repayment of principal to the lender under the terms of the facility. Additionally, the terms of the Company's amended and restated credit facility with Prosperity Bank restrict the Company's ability to incur additional debt. The credit facility contains covenants and other restrictions customary for oil and gas borrowing base credit facilities, including limitations on debt, liens, and dividends, voluntary redemptions of debt, investments, and asset sales. In addition, the credit facility requires that the Company maintain compliance with certain financial tests and financial covenants. If future debt financing is not available to the Company when required as a result of limited access to the credit markets or otherwise, or is not available on acceptable terms, the Company may be unable to invest needed capital for drilling and exploration activities, take advantage of business opportunities, respond to competitive pressures or refinance maturing debt. In addition, the Company may be forced to sell some of the Company's assets on an untimely basis or under unfavorable terms. Any of these results could have a material adverse effect on the Company's operating results and financial conditions.

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The Company's Borrowing Base under its Credit Facility May be Reduced by the Lender.

The borrowing base under the Company's revolving credit facility will be determined from time to time by the lender, consistent with its customary natural gas and crude oil lending practices. Reductions in estimates of the Company's natural gas and crude oil reserves could result in a reduction in the Company's borrowing base, which would reduce the amount of financial resources available under the Company's revolving credit facility to meet its capital requirements. Such a reduction could be the result of lower commodity prices or production, inability to drill or unfavorable drilling results, changes in natural gas and crude oil reserve engineering, the lender's inability to agree to an adequate borrowing base or adverse changes in the lender's practices regarding estimation of reserves. If either cash flow from operations or the Company's borrowing base decreases for any reason, the Company's ability to undertake exploration and development activities could be adversely affected.

As a result, the Company's ability to replace production may be limited. In addition, if the borrowing base is reduced, it would be required to pay down its borrowings under the revolving credit facility so that outstanding borrowings do not exceed the reduced borrowing base. This requirement could further reduce the cash available to the Company for capital spending and, if the Company did not have sufficient capital to reduce its borrowing level, could cause the Company to default under its revolving credit facility.

The Company's Credit Facility is Subject to Variable Rates of Interest, Which Could Negatively Impact the Company.

Borrowings under the Company's credit facility with Prosperity Bank are at variable rates of interest and expose the Company to interest rate risk. If interest rates increase, the Company's debt service obligations on the variable rate indebtedness would increase even though the amount borrowed remained the same, and the Company's income and cash flows would decrease. The Company's credit facility agreement contains certain financial covenants based on the Company's performance. If the Company's financial performance results in any of these covenants being violated, Prosperity Bank may choose to require repayment of the outstanding borrowings sooner than currently required by the agreement.

Declines in Oil or Gas Prices Have and Will Materially Adversely Affect the Company's Revenues.

The Company's financial condition and results of operations depend in large part upon the prices obtainable for the Company's oil and natural gas production and the costs of finding, acquiring, developing and producing reserves. As seen in recent years, prices for oil and natural gas are subject to extreme fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond the Company's control. These factors include worldwide political instability (especially in the Middle East and other oil producing regions), the foreign supply of oil and gas, the price of foreign imports, the level of drilling activity, the level of consumer product demand, government regulations and taxes, the price and availability of alternative fuels, speculating activities in the commodities markets, and the overall economic environment. The Company's operations are substantially adversely impacted as oil prices decline. Lower prices dramatically affect the Company's revenues from its drilling operations. Further, drilling of new wells, development of the Company's leases and acquisitions of new properties are also adversely affected and limited. As a result, the Company's potential revenues from operations as well as the Company's proved reserves may substantially decrease from levels achieved during the period when oil prices were much higher. There can be no assurances as to the future prices of oil or gas. A substantial or extended decline in oil or gas prices would have a material adverse effect on the Company's financial position, results of operations, quantities of oil and gas that may be economically produced, and access to capital. Oil and natural gas prices have historically been and are likely to continue to be volatile.

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This volatility makes it difficult to estimate with precision the value of producing properties in acquisitions and to budget and project the return on exploration and development projects involving the Company's oil and gas properties. In addition, unusually volatile prices often disrupt the market for oil and gas properties, as buyers and sellers have more difficulty agreeing on the purchase price of properties.

Risk in Rates of Oil and Gas Production, Development Expenditures, and Cash Flows May Have a Substantial Impact on the Company's Finances.

Projecting the effects of commodity prices on production, and timing of development expenditures include many factors beyond the Company's control. The future estimates of net cash flows from the Company's proved and other reserves and their present value are based upon various assumptions about future production levels, prices, and costs that may prove to be incorrect over time. Any significant variance from assumptions could result in the actual future net cash flows being materially different from the estimates, which would have a significant impact on the Company's financial position.

The Company Has a History of Significant Losses.

During the early stages of the development of its oil and gas business, the Company had a history of significant losses from operations, in particular its development of the Swan Creek Field and the Company's pipeline assets. In addition, the Company has recorded an impairment of its oil and gas properties during 2008, impairments of its pipeline assets during 2010 and 2012, and an impairment of its methane facility in 2014. As of December 31, 2014, the Company has an accumulated deficit of $23.6 million. The Company recorded net losses of $2.0 million in 2009, $1.7 million in 2010, $0.1 million in 2012, and $0.8 million in 2014. In the event the Company experiences losses in the future, those losses may curtail the Company's development and operating activities.

The Company's Oil and Gas Operations Involve Substantial Cost and are Subject to Various Economic Risks.

The Company's oil and gas operations are subject to the economic risks typically associated with exploration, development, and production activities, including the necessity of making significant expenditures to locate or acquire new producing properties or to drill exploratory and developmental wells. In conducting exploration and development activities, the presence of unanticipated pressure or irregularities in formations, miscalculations, and accidents may cause the Company's exploration, development, and production activities to be unsuccessful. This could result in a total loss of the Company's investment in such well(s) or property. In addition, the cost of drilling, completing and operating wells is often uncertain.

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The Company's Failure to Find or Acquire Additional Reserves Will Result in the Decline of the Company's Reserves Materially From Their Current Levels.

The rate of production from the Company's Kansas oil properties generally declines as reserves are depleted. Except to the extent that the Company either acquires additional properties containing proved reserves, conducts successful exploration and development drilling, or successfully applies new technologies or identifies additional behind-pipe zones or secondary recovery reserves, the Company's proved reserves will decline materially as production from these properties continues. The Company's future oil and natural gas production is consequently highly dependent upon the level of success in acquiring or finding additional reserves or other alternative sources of production. Any decline in oil prices and any prolonged period of lower prices will adversely impact the Company's future reserves since the Company is less likely to acquire additional producing properties during such periods. The lower oil prices have a chilling effect on new drilling and development as such activities become far less likely to be profitable. Thus, any acquisition of new properties poses a greater risk to the Company's financial conditions as such acquisitions may be commercially unreasonable.

In addition, the Company's drilling for oil and natural gas may involve unprofitable efforts not only from dry wells but also from wells that are productive but do not produce sufficient volumes to be commercially profitable after deducting drilling, operating, and other costs. Also, wells that are profitable may not achieve a targeted rate of return. The Company relies on seismic data and other technologies in identifying prospects and in conducting exploration activities. The seismic data and other technologies used do not allow the Company to know conclusively prior to drilling a well whether oil or natural gas is present or may be produced economically.

The ultimate costs of drilling, completing, and operating a well can adversely affect the economics of a project. Further drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including unexpected drilling conditions, title problems, pressure or irregularities in formations, equipment failures, accidents, adverse weather conditions, environmental and other governmental requirements and the cost of, or shortages or delays in the availability of drilling rigs, equipment, and services.

The Company's Reserve Estimates May Be Subject to Other Material Downward Revisions.

The Company's oil and natural gas reserve estimates may be subject to material downward revisions for additional reasons other than the factors mentioned in the previous risk factor entitled "The Company's Failure to Find or Acquire Additional Reserves Will Result in the Decline of the Company's Reserves Materially from their Current Levels." While the future estimates of net cash flows from the Company's proved reserves and their present value are based upon assumptions about future production levels, prices, and costs that may prove to be incorrect over time, those same assumptions, whether or not they prove to be correct, may cause the Company to make drilling or developmental decisions that will result in some or all of the Company's proved reserves to be removed from time to time from the proved reserve categories previously reported by the Company.

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This may occur because economic expectations or forecasts, together with the Company's limited resources, may cause the Company to determine that drilling or development of certain of its properties may be delayed or may not foreseeably occur, and as a result of such decisions any category of proved reserves relating to those yet undrilled or undeveloped properties may be removed from the Company's reported proved reserves. Consequently, the Company's proved reserves of oil may be materially revised downward from time to time.

In addition, the Company may elect to sell some or all of its oil or gas reserves in the normal course of the Company's business. Any such sale would result in all categories of those proved oil or gas reserves that were sold no longer being reported by the Company. In August 2013, the Company sold all of its Tennessee producing oil and gas assets resulting in removal of all Tennessee oil and gas reserves from the Company's reported reserves.

There is Risk That the Company May Be Required to Write Down the Carrying Value of its Natural Gas and Crude Oil Properties.

The Company uses the full cost method to account for its natural gas and crude oil operations. Accordingly, the Company capitalizes the cost to acquire, explore for and develop natural gas and crude oil properties. Under full cost accounting rules, the net capitalized cost of natural gas and crude oil properties and related deferred income tax if any may not exceed a "ceiling limit" which is based upon the present value of estimated future net cash flows from proved reserves, discounted at 10%, plus cost of properties not being amortized and the lower of cost or estimated fair value of unproven properties included in the cost being amortized. If net capitalized cost of natural gas and crude oil properties exceeds the ceiling limit, the Company must charge the amount of the excess, net of any tax effects, to earnings. This charge does not impact cash flow from operating activities, but does reduce the Company's stockholders' equity and earnings. The risk that the Company will be required to write-down the carrying value of natural gas and crude oil properties increases when natural gas and crude oil prices are low. In addition, write-downs may occur if the Company experiences substantial downward adjustments to its estimated proved reserves. An expense recorded in a period may not be reversed in a subsequent period even though higher natural gas and crude oil prices may have increased the ceiling applicable to the subsequent period.

Due to the low oil prices experienced since the quarter ended September 30, 2014, during 2015 the Company expects that ceiling test failures will occur, requiring the Company to write-down its oil and gas properties. If the Company assumes the oil price per barrel, before differentials, remains at $50 per barrel for the remainder of 2015, the Company would anticipate impairments of approximately $20 million during 2015. The actual amount of impairment will be primarily contingent upon the actual oil prices received during 2015.

There is a Risk That the Company May Be Required to Write Down the Carrying Value of its Manufactured Methane Facilities.

The Company's Manufactured Methane facilities are subject to review for impairment whenever events or changes in circumstances indicate that its carrying amount may not be recoverable. The carrying amount is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the methane facility assets. Should this occur, the assets' carrying amount will be reduced to its fair value and the excess over fair value net of any tax effects, will be charged to earnings. This expense may not be reversed in future periods. In 2014, the Company recognized a non-cash impairment of its Manufactured Methane facilities in the amount of $2.8 million ($1.7 million net of tax effect). The impairment resulted from the Company's assessment that future cash flows, using historical costs and runtimes, were insufficient to recover the Manufactured Methane facilities' net book value. The Manufactured Methane facilities were written down to fair value amount calculated from estimated discounted cash flows, as well as certain expressions of interest with regard to the purchase by outside parties of the Company's Manufactured Methane facilities.

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Use of the Company's Net Operating Loss Carryforwards May Be Limited.

At December 31, 2014, the Company had, subject to the limitations discussed in this risk factor, substantial amounts of net operating loss carryforwards for U.S. federal and state income tax purposes. These loss carryforwards will eventually expire if not utilized. In addition, as to a portion of the U.S. net operating loss carryforwards, the amount of such carryforwards that the Company can use annually is limited under U.S. tax laws. Uncertainties exist as to both the calculation of the appropriate deferred tax assets based upon the existence of these loss carryforwards, as well as the future utilization of the operating loss carryforwards under the criteria set forth under FASB ASC 740, Income Taxes. In addition, limitations exist upon use of these carryforwards in the event that a change in control of the Company occurs. There are risks that the Company may not be able to utilize some or all of the remaining carryforwards, or that deferred tax assets that were previously booked based upon such carryforwards may be written down or reversed based on future economic factors that may be experienced by the Company. The effect of such write downs or reversals, if they occur, may be material and substantially adverse.

Shortages of Oil Field Equipment, Services or Qualified Personnel Could Adversely Affect the Company's Results of Operations.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers, and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. The Company does not own any drilling rigs and is dependent upon third parties to obtain and provide such equipment as needed for the Company's drilling activities. There have also been shortages of drilling rigs and other equipment when oil prices have risen. As prices increased, the demand for rigs and equipment increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. These shortages or price increases could adversely affect the Company's profit margin, cash flow, and operating results or restrict the Company's ability to drill wells and conduct ordinary operations.

The Company has Significant Costs to Conform to Government Regulation of the Oil and Gas Industry.

The Company's exploration, production, and marketing operations are regulated extensively at the federal, state and local levels. The Company is currently in compliance with these regulations. In order to maintain its compliance, the Company has made and will continue to make substantial expenditures in its efforts to comply with the requirements of environmental and other regulations. Further, the oil and gas regulatory environment could change in ways that might substantially increase these costs. Hydrocarbon-producing states regulate conservation practices and the protection of correlative rights. These regulations affect the Company's operations and limit the quantity of hydrocarbons it may produce and sell. Other regulated matters include marketing, pricing, transportation and valuation of royalty payments.

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The Company has Significant Costs Related to Environmental Matters.

The Company's operations are also subject to numerous and frequently changing laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. The Company owns or leases, and has owned or leased, properties that have been leased for the exploration and production of oil and gas and these properties and the wastes disposed on these properties may be subject to the Comprehensive Environmental Response, Compensation and Liability Act, the Oil Pollution Act of 1990, the Resource Conservation and Recovery Act, the federal Water Pollution Control Act, the federal Endangered Species Act, and similar state laws. Under such laws, the Company could be required to remove or remediate wastes or property contamination.

Laws and regulations protecting the environment have generally become more stringent and, may in some cases, impose "strict liability" for environmental damage. Strict liability means that the Company may be held liable for damage without regard to whether it was negligent or otherwise at fault. Environmental laws and regulations may expose the Company to liability for the conduct of or conditions caused by others or for acts that were in compliance with all applicable laws at the time they were performed. Failure to comply with these laws and regulations may result in the imposition of administrative, civil and criminal penalties.

The Company's ability to conduct continued operations is subject to satisfying applicable regulatory and permitting controls. The Company's current permits and authorizations and ability to get future permits and authorizations may be susceptible, on a going forward basis, to increased scrutiny, greater complexity resulting in increased cost or delays in receiving appropriate authorizations.

Insurance Does Not Cover All Risks.

Exploration for and development and production of oil can be hazardous, involving unforeseen occurrences such as blowouts, fires, and loss of well control, which can result in damage to or destruction of wells or production facilities, injury to persons, loss of life or damage to property or to the environment. Although the Company maintains insurance against certain losses or liabilities arising from its operations in accordance with customary industry practices and in amounts that management believes to be prudent, insurance is not available to the Company against all operational risks.

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The Company's Methane Extraction Operation from Non-conventional Reserves Involves Substantial Costs and is Subject to Various Economic, Operational, and Regulatory Risks.

The Company's operations in its existing project involving the extraction of methane gas from non-conventional reserves such as landfill gas streams, required investment of substantial capital and is subject to the risks typically associated with capital intensive operations, including risks associated with the availability of financing for required equipment, construction schedules, air and water environmental permitting, and locating transportation facilities and customers for the products produced from those operations which may delay or prevent startup of such projects. After startup of commercial operations, the presence of unanticipated pressures or irregularities in constituents of the raw materials used in such projects from time to time, miscalculations or accidents may cause the Company's project activities to be unsuccessful. Although the technologies to be utilized in such projects are believed to be effective and economical, there are operational risks in the use of such technologies in the combination to be utilized by the Company as a result of both the combination of technologies and the early stages of commercial development and use of such technologies for methane extraction from non-conventional sources such as those to be used by the Company. This risk could result in total or partial loss of the Company's investment in such projects. The economic risks of such projects include the marketing risks resulting from price volatility of the methane gas produced from such projects, which is similar to the price volatility of natural gas. This project is also subject to the risk that the products manufactured may not be accepted for transportation in common carrier gas transportation facilities, although the products meet specified requirements for such transportation, or may be accepted on such terms that reduce the returns of such projects to the Company. This project is also subject to the risk that the product manufactured may not be accepted by purchasers thereof from time to time and the viability of such projects would be dependent upon the Company's ability to locate a replacement market for physical delivery of the gas produced from the project.

We have been granted one U.S. patent and have been granted a continuation patent application relating to certain aspects of our methane extraction technology. Our ability to license our technology is substantially dependent on the validity and enforcement of this patent. We cannot assure you that our patent will not be invalidated, circumvented or challenged, that the rights granted under the patents will provide us competitive advantages. In addition, third parties may seek to challenge, invalidate, circumvent or render unenforceable any patents or proprietary rights owned by or licensed to us based on, among other things: subsequently discovered prior art; lack of entitlement to the priority of an earlier, related application; or failure to comply with the written description, best mode, enablement or other applicable requirements. If a third party is successful in challenging the validity of our patent, our inability to enforce our intellectual property rights could materially harm our methane extraction business. Furthermore, our technology may be the subject of claims of intellectual property infringement in the future. Our technology may not be able to withstand third-party claims or rights against their use.

Any intellectual property claims, with or without merit, could be time-consuming, expensive to litigate or settle, could divert resources and attention and could require us to obtain a license to use the intellectual property of third parties. We may be unable to obtain licenses from these third parties on favorable terms, if at all. Even if a license is available, we may have to pay substantial royalties to obtain a license. If we cannot defend such claims or obtain necessary licenses on reasonable terms, we may be precluded from offering most or all of our technology and our methane extraction business may be adversely affected.

The Company Faces Significant Competition with Respect to Acquisitions or Personnel.

The oil and gas business is highly competitive. In seeking any suitable oil and gas properties for acquisition, or drilling rig operators and related personnel and equipment, the Company is a small entity with limited financial resources and may not be able to compete with most other companies, including large oil and gas companies and other independent operators with greater financial and technical resources and longer history and experience in property acquisition and operation.

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The Company Depends on Key Personnel, Whom it May Not be Able to Retain or Recruit.

Certain members of present management and certain Company employees have substantial expertise in the areas of endeavor presently conducted and to be engaged in by the Company specifically including engineering and geology. To the extent that their services become unavailable, the Company would be required to retain other and additional qualified personnel to perform these services in technical areas upon which the Company is dependent to conduct exploration and production activities. The Company does not know whether it would be able to recruit and hire qualified and additional persons upon acceptable terms. The Company does not maintain "Key Person" insurance for any of the Company's key employees.

The Company's Operations are Subject to Changes in the General Economic Conditions.

Virtually all of the Company's operations are subject to the risks and uncertainties of adverse changes in general economic conditions, the outcome of potential legal or regulatory proceedings, changes in environmental, tax, labor and other laws and regulations to which the Company is subject, and the condition of the capital markets utilized by the Company to finance its operations.

Being a Public Company Significantly Increases the Company's Administrative Costs.

The Sarbanes-Oxley Act of 2002, as well as rules subsequently implemented by the SEC and listing requirements subsequently adopted by the NYSE MKT, the exchange on which the Company's stock is traded, in response to Sarbanes-Oxley, have required changes in corporate governance practices, internal control policies and audit committee practices of public companies. Although the Company is a relatively small public company, these rules, regulations, and requirements for the most part apply to the same extent as they apply to all major publicly traded companies. As a result, they have significantly increased the Company's legal, financial, compliance and administrative costs, and have made certain other activities more time consuming and costly, as well as requiring substantial time and attention of our senior management. The Company expects its continued compliance with these and future rules and regulations to continue to require significant resources. These rules and regulations also may make it more difficult and more expensive for the Company to obtain director and officer liability insurance in the future, and could make it more difficult for it to attract and retain qualified members for the Company's Board of Directors, particularly to serve on its audit committee.

The Company's Chairman of the Board Beneficially Controls a Substantial Amount of the Company's Common Stock and Has Significant Influence over the Company's Business.

Peter E. Salas, the Chairman of the Company's Board of Directors, is the sole shareholder and controlling person of Dolphin Mgmt. Services, Inc. the general partner of Dolphin Offshore Partners, L.P. ("Dolphin"), which is the Company's largest shareholder. At March 20, 2015, Mr. Salas individually and through Dolphin controls 21,057,492 shares of the Company's common stock and had options granting him the right to acquire an additional 125,000 shares of common stock. His ownership and voting control of approximately 34% of the Company's common stock gives him significant influence on the outcome of corporate transactions or other matters submitted to the Board of Directors or shareholders for approval, including mergers, consolidations, and the sale of all or substantially all of the Company's assets.

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Shares Eligible for Future Sale May Depress the Company’s Stock Price.

At March 24, 2015, the Company had 60,842,413 shares of common stock outstanding of which 21,326,718 shares were held by officers, directors, and affiliates. In addition, options to purchase 855,250 shares of unissued common stock were granted under the Tengasco, Inc. Stock Incentive Plan all of which were vested at March 24, 2015.

All of the shares of common stock held by affiliates are restricted or controlled securities under Rule 144 promulgated under the Securities Act of 1933, as amended (the “Securities Act”). The shares of the common stock issuable upon exercise of the stock options have been registered under the Securities Act. Sales of shares of common stock under Rule 144 or another exemption under the Securities Act or pursuant to a registration statement could have a material adverse effect on the price of the common stock and could impair the Company’s ability to raise additional capital through the sale of equity securities.

Future Issuance of Additional Shares of the Company’s Common Stock Could Cause Dilution of Ownership Interest and Adversely Affect Stock Price.

The Company may in the future issue previously authorized and unissued securities, resulting in the dilution of the ownership interest of its current stockholders. The Company is currently authorized to issue a total of 100 million shares of common stock with such rights as determined by the Board of Directors. Of that amount, approximately 61 million shares have been issued. The potential issuance of the approximately 39 million remaining authorized but unissued shares of common stock may create downward pressure on the trading price of the Company’s common stock.

The Company may also issue additional shares of its common stock or other securities that are convertible into or exercisable for common stock for raising capital or other business purposes. Future sales of substantial amounts of common stock, or the perception that sales could occur, could have a material adverse effect on the price of the Company’s common stock.

The Company May Issue Shares of Preferred Stock with Greater Rights than Common Stock.

Subject to the rules of the NYSE MKT, the Company’s charter authorizes the Board of Directors to issue one or more series of preferred stock and set the terms of the preferred stock without seeking any further approval from holders of the Company’s common stock. Any preferred stock that is issued may rank ahead of the Company’s common stock in terms of dividends, priority and liquidation premiums and may have greater voting rights than the Company’s common stock.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES.

Property Location, Facilities, Size and Nature of Ownership.

The Company leases its principal executive offices, consisting of approximately 3,021 square feet located at 6021 S. Syracuse Way, Suite 117, Greenwood Village, Colorado at an initial rental of $3,965 per month, expiring in May 2017. The Company also leases an office in Hays, Kansas at a rental of $750 per month that is currently a month to month lease.

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The Company carries insurance on its Kansas properties, methane facility, offices, vehicles, and office contents. As of December 31, 2014, the Company does not have an interest in producing or non-producing oil and gas properties in any state other than Kansas.

Kansas Properties

The Kansas Properties as of December 31, 2014 contained 27,189 gross acres in central Kansas. Of these 27,189 gross acres, 14,230 acres were held by production and 12,959 acres were undeveloped.

Many of these leases are still in effect because they are being held by production. The Kansas leases provide for a landowner royalty of 12.5%. Some wells are subject to an overriding royalty interest from 0.5% to 9%. The Company maintains a 100% working interest in most of its wells and undrilled acreage in Kansas. The terms for most of the Company's newer leases in Kansas are from three to five years.

During 2014, the Company drilled 9 gross wells and completed 1 well that was drilling at the end of 2013. All of these wells were operated by the Company and the Company has a working interest of 100% in each well. Of the 9 wells drilled in 2014, 4 of the wells were completed as producing wells.

All of the Company's current reserve value, production, oil and gas revenue, and future development objectives result from the Company's ongoing interest in Kansas. By using 3-D seismic evaluation on the Company's existing locations, the Company has historically added proven direct offset locations and will continue using 3-D seismic evaluation techniques in the future.

Tennessee Properties

The Company closed the sale of all its Tennessee oil and gas properties on August 16, 2013.

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Reserve and Production Summary

The following tables indicate the county breakdown of 2014 production and reserve values as of December 31, 2014.

Production by County

| Area | Gross Production MBOE | Average Net Revenue Interest | Percentage of Total Oil Production |
|---|---|---|---|
| Rooks County, KS | 116.5 | 0.824264 | 62.8 % |
| Trego County, KS | 33.8 | 0.809680 | 18.2 % |
| Ellis County, KS | 9.6 | 0.808810 | 5.2 % |
| Barton County, KS | 6.9 | 0.818072 | 3.7 % |
| Graham County, KS | 5.8 | 0.862460 | 3.1 % |
| Russell County, KS | 3.9 | 0.855852 | 2.1 % |
| Pawnee County, KS | 3.4 | 0.813759 | 1.8 % |
| Rush County, KS | 2.7 | 0.864319 | 1.5 % |
| Osborne County, KS | 1.7 | 0.591493 | 0.9 % |
| Stafford County, KS | 1.3 | 0.716138 | 0.7 % |
| Total | 185.6 | | 100.0 % |

Reserve Value by County Discounted at 10% (in thousands)

| Area | Proved Developed | Proved Undeveloped | Proved Reserves | % of Total |
|---|---|---|---|---|
| Rooks County, KS | $ 22,400 | $ 2,533 | $ 24,933 | 61.7 % |
| Trego County, KS | 6,356 | 1,023 | 7,379 | 18.3 % |
| Graham County, KS | 1,376 | 1,732 | 3,108 | 7.7 % |
| Ellis County, KS | 1,884 | - | 1,884 | 4.7 % |
| Barton County, KS | 1,124 | - | 1,124 | 2.8 % |
| Russell County, KS | 827 | - | 827 | 2.0 % |
| Rush County, KS | 691 | - | 691 | 1.7 % |
| Pawnee County, KS | 236 | - | 236 | 0.6 % |
| Stafford County, KS | 102 | 74 | 176 | 0.4 % |
| Osborne County, KS | 18 | 41 | 59 | 0.1 % |
| Total | $ 35,014 | $ 5,403 | $ 40,417 | 100.0 % |

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Reserve Analyses

The Company's estimated total net proved reserves of oil and natural gas as of December 31, 2014 and 2013, and the present values of estimated future net revenues attributable to those reserves as of those dates, are presented in the following tables. All of the Company's reserves were located in the United States. These estimates were prepared by LaRoche Petroleum Consultants, Ltd. ("LaRoche") of Dallas, Texas, and are part of their reserve reports on the Company's oil and gas properties. LaRoche and its employees and its registered petroleum engineers have no interest in the Company and performed those services at their standard rates. LaRoche's estimates were based on a review of geologic, economic, ownership, and engineering data provided to them by the Company. In accordance with SEC regulations, no price or cost escalation or reduction was considered. The technical persons at LaRoche responsible for preparing the Company's reserve estimates meet 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. Our independent third party engineers do not own an interest in any of our properties and are not employed by the Company on a contingent basis.

Total Proved Reserves as of December 31, 2014

| | Producing | Non Producing | Undeveloped | Total |
|---|---|---|---|---|
| Oil (MBbl) | 1,360 | 78 | 359 | 1,797 |
| Future net cash flows before income taxes discounted at 10% (in thousands) | $ 32,059 | $ 2,955 | $ 5,403 | $40,417 |

Total Proved Reserves as of December 31, 2013

| | Producing | Non-producing | Undeveloped | Total |
|---|---|---|---|---|
| Oil (MBbl) | 1,465 | 110 | 465 | 2,040 |
| Future net cash flows before income taxes discounted at 10% (in thousands) | $ 34,440 | $ 4,868 | $ 8,548 | $47,856 |

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Historically, all drilling has primarily been funded by cash flows from operations with supplemental funding provided by the Company's credit facility. The Company's Proved Undeveloped Reserves at December 31, 2014 included 27 locations as compared to 29 locations at December 31, 2013. During 2014, one of the PUDs contributing reserves of 12 MBbl that existed at December 31, 2013 was drilled and moved into proved developed reserves, 9 PUDs contributing reserves of 155 MBbl were dropped from the PUD reserves at December 31, 2014, and there was a 50 MBbl downward revision in PUD reserves. These reductions were partially offset by the addition of 8 PUD locations which contributed 111 MBbl of reserves at December 31, 2014. Of the 9 locations that were dropped from the PUD reserves, 6 of these locations were dropped since they reached the 5 year limit that the Company is allowed to carry specific locations as a PUD reserve. The future development cost related to the Company's Proved Undeveloped locations at December 31, 2014 was approximately $8.7 million. The Company intends to fund the drilling of these locations through operating cash flow and, as needed, supplement the funding by drawing on the Company's credit facility. All proved undeveloped reserves included in the Company's report at December 31, 2014 and 2013 are related to oil prospects in Kansas. During 2013, approximately 16.7 MBbl of proved undeveloped reserves that existed at December 31, 2012 were converted into proved developed reserves.

The oil price after basis adjustments used in our December 31, 2014 reserve valuation was $88.34 per Bbl compared to $90.11 per Bbl used in our December 31, 2013 reserve valuation. The primary factors causing the decrease in proved reserve volumes from December 31, 2013 levels were 2014 proved developed reserve additions not being significant enough to offset 2014 production as well as downward revisions of certain producing properties, recompletions and polymers, and proved undeveloped locations. (Refer to Note 15, Supplemental Oil and Gas Information, Standardized Measure of Discounted Future Net Cash Flows in the Company's Notes to Consolidated Financial Statements for additional reserve information.)

The assumed prices used in calculating the estimated future net revenue attributable to proved reserves do not necessarily reflect actual market prices for oil production sold after December 31, 2014. There can be no assurance that all of the estimated proved reserves will be produced and sold at the assumed prices. Accordingly, the foregoing prices should not be interpreted as a prediction of future prices.

In substance, the LaRoche Report used estimates of oil and gas reserves based upon standard petroleum engineering methods which include production data, decline curve analysis, volumetric calculations, pressure history, analogy, various correlations and technical factors. Information for this purpose was obtained from owners of interests in the areas involved, state regulatory agencies, commercial services, outside operators and files of LaRoche.

Management has established, and is responsible for, internal controls designed to provide reasonable assurance that the estimates of Proved Reserves are computed and reported in accordance with SEC rules and regulations as well as with established industry practices. The Company's Exploration Manager and Petroleum Engineer each have extensive experience evaluating reserves on a well by well basis and on a company wide basis. Prior to generation of the annual reserves, management and staff meet with LaRoche to review properties and discuss assumptions to be used in the calculation of reserves. Management reviews all information submitted to LaRoche to ensure the accuracy of the data. Management also reviews the final report from LaRoche and discusses any differences from Management expectations with LaRoche.

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Production

The following tables summarize for the past three fiscal years the volumes of oil and gas produced from operated properties, the Company's operating costs, and the Company's average sales prices for its oil and gas. The net production volumes excluded volumes produced to royalty interest or other parties' working interest. Tennessee amounts in 2013 represent results through August 16, 2013 when these properties were sold.

Kansas

| Years Ended December 31, | Gross Production | | Net Production | | Cost of Net Production | Average Sales Price | |
|---|---|---|---|---|---|---|---|
| | Oil (MBbl) | Gas (MMcf) | Oil (MBbl) | Gas (MMcf) | (Per BOE) | Oil (Bbl) | Gas (Per Mcf) |
| 2014 | 185.6 | - | 152.2 | - | $ 31.77 | $86.05 | - |
| 2013 | 203.9 | - | 162.5 | - | $ 28.27 | $91.00 | - |
| 2012 | 278.8 | - | 225.9 | - | $ 22.48 | $86.90 | - |

Tennessee

| Years Ended December 31, | Gross Production | | Net Production | | Cost of Net Production | Average Sales Price | |
|---|---|---|---|---|---|---|---|
| | Oil (MBbl) | Gas (MMcf) | Oil (MBbl) | Gas (MMcf) | (Per BOE) | Oil (Bbl) | Gas (Per Mcf) |
| 2013 | 3.8 | 51.3 | 2.7 | 37.9 | $ 28.90 | $92.66 | $3.94 |
| 2012 | 4.9 | 78.8 | 3.5 | 56.2 | $ 39.08 | $88.29 | $3.35 |

Oil and Gas Drilling Activities

Kansas

During 2014, the Company drilled 9 gross wells and completed 1 well that was drilling at the end of 2013. All of these wells were operated by the Company and the Company has a working interest of 100% in each well. Of the 9 wells drilled in 2014, 4 of the wells were completed as producing wells.

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Tennessee

In August 2013, the Company completed the sale of all its oil and gas producing and non-producing properties in Tennessee.

Gross and Net Wells

The following tables set forth the fiscal years ending December 31, 2014, 2013 and 2012 the number of gross and net development wells drilled by the Company. The term gross wells means the total number of wells in which the Company owns an interest, while the term net wells means the sum of the fractional working interest the Company owns in the gross wells.

| | For Years Ending December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2014 | | 2013 | | 2012 | |
| | Gross | Net | Gross | Net | Gross | Net |
| Kansas | | | | | | |
| Productive Wells | 5 | 5 | 6 | 5 | 15 | 15 |
| Dry Holes | 5 | 5 | - | - | 5 | 5 |

Productive Wells

As of December 31, 2014, the Company held a working interest in 215 gross wells and 209 net wells in Kansas. Productive wells are either producing wells or wells capable of commercial production although currently shut-in. One or more completions in the same bore hole are counted as one well. The term gross wells means the total number of wells in which the Company owns an interest, while the term net wells means the sum of the fractional working interests the Company owns in all of the gross wells. Tennessee productive wells were sold in August 2013.

Developed and Undeveloped Oil and Gas Acreage

As of December 31, 2014 the Company owned working interests in the following developed and undeveloped oil and gas acreage. The term gross acres means the total number of acres in which the Company owns an interest, while the term net acres means the sum of the fractional working interest the Company owns in the gross acres, less the interest of royalty owners.

| | Developed | | Undeveloped | | Total | |
|---|---|---|---|---|---|---|
| | Gross Acres | Net Acres | Gross Acres | Net Acres | Gross Acres | Net Acres |
| Kansas | 14,230 | 11,756 | 12,959 | 10,299 | 27,189 | 22,055 |

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The following table identifies the number of gross and net undeveloped acres as of December 31, 2014 that will expire, by year, unless production is established before lease expiration or unless the lease is renewed.

| | 2015 | 2016 | 2017 | Total |
|---|---|---|---|---|
| Gross Acres | 2,486 | 3,200 | 7,273 | 12,959 |
| Net Acres | 2,073 | 2,547 | 5,679 | 10,299 |

## ITEM 3. LEGAL PROCEEDINGS

The Company is not a party to any pending material legal proceeding. To the knowledge of management, no federal, state, or local governmental agency is presently contemplating any proceeding against the Company which would have a result materially adverse to the Company. To the knowledge of management, no director, executive officer or affiliate of the Company or owner of record or beneficially of more than 5% of the Company's common stock is a party adverse to the Company or has a material interest adverse to the Company in any proceeding.

## 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

### Market Information

The Company's common stock is listed on the NYSE MKT exchange under the symbol TGC. The range of high and low sales prices for shares of common stock of the Company as reported on the NYSE MKT during the fiscal years ended December 31, 2014 and December 31, 2013 are set forth below.

| For the Quarters Ending | High | Low |
|---|---|---|
| March 31, 2014 | $0.57 | $0.37 |
| June 30, 2014 | $0.52 | $0.41 |
| September 30, 2014 | $0.50 | $0.40 |
| December 31, 2014 | $0.51 | $0.25 |
| March 31, 2013 | $0.82 | $0.60 |
| June 30, 2013 | $0.71 | $0.48 |
| September 30, 2013 | $0.58 | $0.35 |
| December 31, 2013 | $0.48 | $0.37 |

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Holders

As of March 24, 2015, the number of shareholders of record of the Company's common stock was 275 and management believes that there are approximately 1,869 beneficial owners of the Company's common stock.

Dividends

The Company did not pay any dividends with respect to the Company's common stock in 2014 or 2013 and has no present plans to declare any dividends with respect to its common stock.

Recent Sales of Unregistered Securities

During the fourth quarter of fiscal 2014, the Company did not sell or issue any unregistered securities. Any unregistered equity securities that were sold or issued by the Company during the first three quarters of fiscal 2014 were previously reported in Reports filed by the Company with the SEC.

Purchases of Equity Securities by the Company and Affiliated Purchasers

Neither the Company nor any of its affiliates repurchased any of the Company's equity securities during 2014.

Equity Compensation Plan Information

See Item 12, "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matter" for information regarding the Company's equity compensation plans.

ITEM 6. SELECTED FINANCIAL DATA

Not Applicable.

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

Results of Operations

The Company reported net loss from continuing operations of $(788,000) or $(0.01) per share in 2014 compared to net income from continuing operations of $3.0 million or $0.05 per share in 2013 and net income from continuing operations of $4.2 million or $0.07 per share in 2012. The Company did not report net income or loss from discontinued operations in 2014 as the Company's pipeline assets were sold in August 2013. The Company did report a net loss from discontinued operations of $(0.14) million or $(0.00) per share in 2013 compared to a net loss from discontinued operations of $(4.3) million or $(0.07) per share in 2012. The net loss from discontinued operations in 2012 was primarily due to impairments of the Company's pipeline assets in the amounts of approximately $3.4 million. Discontinued operations are net of associated taxes.

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The Company realized revenues of approximately $13.8 million in 2014 compared to $15.7 million in 2013 and $20.6 million in 2012. During 2014, revenues decreased approximately $(1.9) million of which $1.2 million was related to decreases in oil sales volumes from 166.2 MBbl in 2013 to 153.5 MBbl in 2014. The more significant production declines were experienced in the Albers, Coddington, Liebenau, McElhaney A, Veverka A, and Veverka C leases. These decreases were primarily due to natural declines from higher levels of production as a result of drilling and polymers on these leases during 2011 and the first half of 2012. These production declines were partially offset by production from the successful drilling of the Albers B #3, Albers C #1, Howard A #1, and Veverka D #4 wells and recompletions of the Hammeke #3 and McElhaney #1 wells. In addition, $764,000 of this decrease related to a $4.98 per barrel decrease in the average oil price received from $91.03 per barrel received in 2013 to $86.05 per barrel received in 2014. Also, there was a $140,000 decrease related to lower gas sales as the Tennessee oil and gas assets were sold in 2013 and a $117,000 decrease in gas sales at the Methane facility as the Company focused on electric generation only in 2014. These decreases were partially offset by a $261,000 increase in electric generation revenues at the landfill related to an increase in runtime from 27% during 2013 to 56% during 2014. During 2013, revenues decreased $4.9 million of which $5.2 million related to decreases in oil sales volumes from 226.6 MBbl in 2012 to 166.2 MBbl in 2013. The more significant production declines were experienced in the Albers, Coddington, Hilgers B, Liebenau, McElhaney A, Veverka A, and Zerger A leases. These decreases were primarily due to higher 2012 production as a result of drilling and polymers on these leases during 2011 and the first half of 2012. In addition there was also a $(0.3) million decrease in sales from the Manufactured Methane facilities at the landfill related to increased downtime as a result of consistent high levels of oxygen in the landfill gas during 2013 which caused equipment to shut down until lower oxygen levels on a consistent basis were achieved. These decreases were partially offset by a $0.7 million increase related to a $4.11 per barrel increase in the average oil price received from $86.92 per barrel received in 2012 to $91.03 per barrel received in 2013. Gas prices received for sales of gas from the Swan Creek Field averaged $3.94 per Mcf in 2013, $3.35 per Mcf in 2012, and $4.28 per Mcf in 2011. Oil prices received for sales of oil from the Swan Creek field averaged $92.66 per barrel in 2013, $88.29 per barrel in 2012, and $87.33 per barrel in 2011. Swan Creek field results during 2013 reflect only operating from the beginning of 2013 until the field was sold in August 2013.

The Company's production costs and taxes were approximately $6.0 million in 2014, $5.5 million in 2013, and $7.2 million in 2012. The $0.5 million increase in 2014 primarily related to a one-time $386,000 expense recorded during 2014 as a result of the IBLA affirmation of the civil penalty related to the 2012 Incident of Non-Compliance by the BSEE on one of Hoactzin's properties, a $307,000 increase due to changes in oil inventory, and a $226,000 increase in well workover and repair cost primary related to work done on the Croffoot B #6 SWD, M. Rogers #2, H Karst SWD, Liebenau #8 and Wehrli #1 wells. These increases were partially offset by a $109,000 decrease in Swan Creek costs as these assets were sold in August 2013, a $185,000 decrease in Kansas property taxes related to natural declines as well as successful appeals, and a $68,000 decrease in landfill expenses primarily due to lower payroll costs. The $(1.7) million decrease in 2013 related primarily to a $(0.4) million decrease in Kansas property taxes primarily related to successful appeals of 2012 property taxes, $(0.2) million reduction in Gulf of Mexico related operating cost as the Management Agreement with Hoactzin expired in December 2012, $(0.2) million decrease in Manufactured Methane facilities costs, and $(0.2) million related to Swan Creek and pipeline asset cost as these were sold in August 2013.

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Depreciation, depletion, and amortization were approximately $3.0 million in 2014, $2.9 million in 2013, and $3.4 million in 2012. The $118,000 increase in 2014 was primarily related to $448,000 due to an increase in the oil and gas depletion rate, a $26,000 increase in the methane facilities depreciation primarily related to capital spending in late 2013 and early 2014, partially offset by $(288,000) related to lower oil and gas sales volumes, and $(68,000) lower depreciation expense on other equipment due to the sale of the Tennessee oil and gas assets. The $(0.5) million decrease in 2013 was primarily related to lower oil and gas depletion expense due to lower sales volume partially offset by an increase in the depletion rate.

The Company's general and administrative cost was approximately $2.7 million in 2014, $2.1 million in 2013, and $2.6 million in 2012. The $648,000 increase in 2014 was primarily related to $290,000 of costs incurred in 2014 for personnel, relocation cost, and office cost related to set up of the Denver office, a 2013 $98,000 reversal of a bad debt expense associated with the related party receivable, and $66,000 of consulting cost incurred in 2014 related to evaluating potential opportunities and review of the methane facility. The $(554,000) decrease in 2013 was a $(341,000) decrease in bad debt expense primarily as a result of recording in 2012 $257,000 of expense for Hoactzin-related receivables that was decreased by $(98,000) in 2013 as a portion of the related payables were paid and or re-billed to Hoactzin, and a $(199,000) decrease in legal, accounting, and consulting expenses. Compensation expense related to stock options was $32,000 in 2014 and was $(28,000) in 2013 and $52,000 in 2012. The 2013 amount was comprised of $32,000 of current year compensation expense offset by reversal of $59,500 previously recognized as compensation expense.

In 2014, the Company recorded a non-cash impairment of its Manufactured Methane facilities in the amount of $2.8 million ($1.7 million net of tax effect). The impairment resulted from the Company's assessment that future cash flows, using historical costs and runtimes, were insufficient to recover the Manufactured Methane facilities' net book value. The Manufactured Methane facilities were written down to fair value amount calculated from future discounted cash flows, using the same historical costs and runtimes, as well as certain expressions of interest with regards to the purchase by outside parties of the Company's Manufactured Methane facilities. Although the Company believes the value realized from continued use of the Manufactured Methane facilities will be higher than the current carrying value, there can be no assurance that the Company will be able to increase runtime or reduce operating costs. Even if the Company is able to increase runtime and reduce operating cost, the impairment recorded in 2014 cannot be reversed in a later period.

In 2012, the Company recorded a non-cash impairment of its pipeline assets in the amount of $5.2 million ($3.4 million net of tax effect). The pipeline assets were classified as assets held for sale in the Company's Consolidated Balance Sheet as of December 31, 2012. These write downs resulted from the Company's assessment that cash flows generated from the pipeline were insufficient to recover the pipeline's net book value. During 2012 and 2010, the Company received expressions of interest from potential purchasers of the pipeline asset which were significantly below the asset's pre write down net book values. These expressions of interest indicated that the carrying amount of the pipeline may not be recoverable. At December 31, 2012, the Company was in the process of negotiating an agreement to sell the pipeline assets and the Swan Creek Field wells and associated equipment. Preliminary allocation of the sales value to the pipeline assets indicated a write down of approximately $5.2 million, before tax effect, was necessary. The pipeline asset was sold in August 2013.

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Net interest expense was $88,000 in 2014, $357,000 in 2013, and $743,000 in 2012. The $(269,000) decrease in interest expense in 2014 was primarily due to a $4.4 million decrease in the average credit facility balance from $6.1 million during 2013 to $1.7 million during 2014. The decrease was primarily due to low drilling, recompletion, and polymer activities during 2014 resulting in operating cash flows in excess of drilling, recompletion, and polymer costs being used to pay down the credit facility. The $(386,000) decrease in interest expense in 2013 was primarily due to a $6.5 million decrease in the average credit facility balance from $12.6 million during 2012 to $6.1 million during 2013. The decrease was primarily due to low drilling and polymer activities during the second half of 2012 and all of 2013 resulting in operating cash flows in excess of drilling and polymer costs being used to pay down the credit facility.

During 2014 and 2013, the Company did not have any open derivative positions. During 2012, the Company recorded a $(0.14) million loss on derivatives. The 2012 loss on derivatives was comprised solely of an unrealized loss (See Item 7A. "Commodity Risk").

The Company recorded income tax benefit on continuing operations of $6,000 in 2014, and income tax expense of $2.0 million in 2013, and $2.3 million in 2012. (See Note 14. Income Taxes in Notes to Consolidated Financial Statements)

Due to the low oil prices experienced since the quarter ended September 30, 2014, during 2015 the Company expects that ceiling test failures will occur, requiring the Company to write-down its oil and gas properties. If the Company assumes the oil price per barrel, before differentials, remains at $50 per barrel for the remainder of 2015, the Company would anticipate impairments of approximately $20 million during 2015. The actual amount of impairment will be primarily contingent upon the actual oil prices received during 2015.

Liquidity and Capital Resources

At December 31, 2014, the Company had a revolving credit facility with Prosperity Bank (formerly F&M Bank & Trust Company). This is the Company's primary source to fund working capital and future capital spending. Under the credit facility, loans and letters of credit are available to the Company on a revolving basis in an amount outstanding not to exceed the lesser of $40 million or the Company's borrowing base in effect from time to time. As of December 31, 2014, the Company's borrowing base was $14.3 million. The borrowing base was reduced to $7.8 million with the March 16, 2015 amendment to the credit agreement. This reduction was primarily related to the significant decrease in the prices used by Prosperity Bank during their most recent borrowing base redetermination. The credit facility is secured by substantially all of the Company's producing and non-producing oil and gas properties and the Company's Manufactured Methane facilities. The credit facility includes certain covenants with which the Company is required to comply. These covenants include leverage, interest coverage, and minimum liquidity ratios. During 2014, 2013, and 2012, the Company was in compliance with all covenants.

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On March 27, 2014, the Company's senior credit facility with Prosperity Bank after Prosperity Bank's semiannual review of the Company's currently owned producing properties was amended to reduce the Company's borrowing base from $17.5 million to $14.3 million and extend the term of the facility to January 27, 2016. The interest rate remained prime plus 0.50%.

On March 16, 2015, the Company's senior credit facility with Prosperity Bank after Prosperity Bank's semiannual review of the Company's then owned producing properties was amended to reduce the Company's borrowing base from $14.3 million to $7.8 million and extend the term of the facility to January 27, 2017. The interest rate remained prime plus 0.50%.

The total borrowing by the Company under the facility at December 31, 2014 and December 31, 2013 was $734,000 and $3.3 million, respectively. The Company's outstanding borrowing under the facility as of March 27, 2015 was approximately $843,000. The next borrowing base review will take place in July 2015.

Net cash provided by operating activities from continuing operations was $6.6 million in 2014, $8.0 million in 2013, and $9.3 million in 2012. Net cash used in operating activities from discontinued operations was $(85,000) in 2013 and $(265,000) in 2012. The decrease in cash provided by operating activities in 2014 was primarily related to a $(1.9 million) decrease due to lower oil volumes and prices, $(648,000) due to an increase in general and administrative expense, a $(470,000) decrease due to an increase in production costs and taxes, partially offset by a $1.2 million increase in cash provided by working capital. The decrease in cash provided by operating activities in 2013 was primarily related to a decrease in sales volumes, partially offset by increased oil prices, reduction in production costs and taxes, reduction in general and administrative costs and $1.3 million increase in cash flow provided by working capital. The increase in cash provided by operating activities from continuing operations in 2012 was primarily due to a $3.3 million increase related to increased sales volumes, partially offset by a $(1.3) million increase in production costs and taxes and a $(1.2) million decrease in changes in working capital. Cash flow provided by working capital was $1.4 million in 2014, and was $188,000 in 2013, and cash flow used in working capital was $(1.1) million in 2012. The primary difference in changes in working capital in 2014 as compared to 2013 was a $449,000 decrease in inventory, a $576,000 decrease in accounts receivable primarily due to lower December revenues and reduction of related party receivables, a $323,000 increase in accrued liabilities, and a $121,000 receipt of the refund of the certificate of deposit used to collateralize Tennessee plugging obligations, The difference in changes in working capital in 2013 as compared to 2012 was primarily posting cash collateral related to the appeal bond in 2012 and 2012 increase in equipment and materials inventory, partially offset by lower receivables in 2013 related to lower year-end revenues in 2013 as compared to 2012.

Net cash used in investing activities from continuing operations was $4.0 million in 2014, $2.2 million in 2013, and $7.6 million in 2012. The $1.8 million increase in cash used in investing activities during 2014 as compared to 2013 was due primarily to a $1.4 million increase in drilling and recompletion activities during 2014 as compared to 2013, and a $280,000 increase in Manufactured Methane facility costs primarily related to equipment and reconfiguration of the electric generator. The $5.4 million decrease in cash provided by investing activities in 2013 as compared to 2012 was due to decreased drilling and polymer activities in 2013 as compared to 2012, 2012 additions to the Manufactured Methane facilities, partially offset by the $1.0 million received in 2012 for payment in lieu of tax credits related to the Manufactured Methane facilities.

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Net cash used in financing activities from continuing operations was $2.6 million in 2014, $5.7 million in 2013, and $1.8 million in 2012 resulting from excess cash flows from continuing operations used to pay down the Company's credit facility. Net cash used in financing activities from discontinued operations in 2013 was $(1.3) million resulting in the sale of the Company's pipeline assets. Net cash provided by financing activities from discontinued operations was $265,000 in 2012. This funding in 2012 was used to finance the Company's pipeline operations.

Critical Accounting Policies

The Company prepares its Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America, which require the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the year. Actual results could differ from those estimates. The Company considers the following policies to be the most critical in understanding the judgments that are involved in preparing the Company's financial statements and the uncertainties that could impact the Company's results of operations, financial condition and cash flows.

Revenue Recognition

Revenues are recognized based on actual volumes of oil, natural gas, methane gas, and electricity sold to purchasers at a fixed or determinable price, when delivery has occurred and title has transferred, and collectability is reasonably assured. Crude oil is stored and at the time of delivery to the purchasers, revenues are recognized. Natural gas meters are placed at the customer's location and usage is billed each month. There were no natural gas imbalances at December 31, 2014 and 2013 as the Company sold its Tennessee oil and gas properties in August 2013. Methane gas and electricity sales meters are located at the Carter Valley landfill site and electricity generation sales are billed each month. No methane gas was sold during 2014.

Full Cost Method of Accounting

The Company follows the full cost method of accounting for oil and gas property acquisition, exploration, and development activities. Under this method, all costs incurred in connection with acquisition, exploration and development of oil and gas reserves are capitalized. Capitalized costs include lease acquisitions, seismic related costs, certain internal exploration costs, drilling, completion, and estimated asset retirement costs. The capitalized costs of oil and gas properties, plus estimated future development costs relating to proved reserves and estimated asset retirement costs which are not already included net of estimated salvage value, are amortized on the unit-of-production method based on total proved reserves. The Company has determined its reserves based upon reserve reports provided by LaRoche Petroleum Consultants Ltd. since 2009. The costs of unproved properties are excluded from amortization until the properties are evaluated, subject to an annual assessment of whether impairment has occurred. The Company had $462,000 and $736,000 in unevaluated properties as of December 31, 2014 and 2013, respectively. Proceeds from the sale of oil and gas properties are accounted for as reductions to capitalized costs unless such sales cause a significant change in the relationship between costs and the estimated value of proved reserves, in which case a gain or loss is recognized. At the end of each reporting period, the Company performs a "ceiling test" on the value of the net capitalized cost of oil and gas properties. This test compares the net capitalized cost (capitalized cost of oil and gas properties, net of accumulated depreciation, depletion and amortization and related deferred income taxes) to the present value of estimated future net revenues from oil and gas properties using an average price (arithmetic average of the beginning of month prices for the prior 12 months) and current cost discounted at 10% plus cost of properties not being amortized and the lower of cost or estimated fair value of unproven properties included in the cost being amortized (ceiling). If the net capitalized cost is greater than the ceiling, a write-down or impairment is required. A write-down of the carrying value of the asset is a non-cash charge that reduces earnings in the current period. Once incurred, a write-down cannot be reversed in a later period.

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Oil and Gas Reserves/Depletion, Depreciation, and Amortization of Oil and Gas Properties

The capitalized costs of oil and gas properties, plus estimated future development costs relating to proved reserves and estimated asset retirement costs which are not already included net of estimated salvage value, are amortized on the unit-of-production method based on total proved reserves. The costs of unproved properties are excluded from amortization until the properties are evaluated, subject to an annual assessment of whether impairment has occurred.

The Company's proved oil and gas reserves as of December 31, 2014 were determined by LaRoche Petroleum Consultants, Ltd. Projecting the effects of commodity prices on production, and timing of development expenditures includes many factors beyond the Company's control. The future estimates of net cash flows from the Company's proved reserves and their present value are based upon various assumptions about future production levels, prices, and costs that may prove to be incorrect over time. Any significant variance from assumptions could result in the actual future net cash flows being materially different from the estimates.

Asset Retirement Obligations

The Company's asset retirement obligations relate to the plugging, dismantling, and removal of wells drilled to date. The Company follows the requirements of FASB ASC 410, "Asset Retirement Obligations and Environmental Obligations". Among other things, FASB ASC 410 requires entities to record a liability and corresponding increase in long-lived assets for the present value of material obligations associated with the retirement of tangible long-lived assets. Over the passage of time, accretion of the liability is recognized as an operating expense and the capitalized cost is depleted over the estimated useful life of the related asset. If the estimated future cost of the asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the long-lived asset. Revisions to estimated asset retirement obligations can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimated timing of abandonment. The Company currently uses an estimated useful life of wells ranging from 20-40 years. Management continues to periodically evaluate the appropriateness of these assumptions.

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Income Taxes

Income taxes are reported in accordance with U.S. GAAP, which requires the establishment of deferred tax accounts for all temporary differences between the financial reporting and tax bases of assets and liabilities, using currently enacted federal and state income tax rates. In addition, deferred tax accounts must be adjusted to reflect new rates if enacted into law. Temporary differences result principally from federal and state net operating loss carryforwards, differences in oil and gas property values resulting from a 2008 ceiling test write down, and differences in methods of reporting depreciation and amortization. Management routinely assesses the ability to realize our deferred tax assets and reduces such assets by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be recognized.

At December 31, 2014, federal net operating loss carryforwards amounted to approximately $20.2 million which expire between 2019 and 2031. The total deferred tax asset was $7.35 million and $7.34 million at December 31, 2014 and 2013, respectively.

Realization of deferred tax assets is contingent on the generation of future taxable income. As a result, management considers whether it is more likely than not that all or a portion of such assets will be realized during periods when they are available, and if not, management provides a valuation allowance for amounts not likely to be recovered.

Management periodically evaluates tax reporting methods to determine if any uncertain tax positions exist that would require the establishment of a loss contingency. A loss contingency would be recognized if it were probable that a liability has been incurred as of the date of the financial statements and the amount of the loss can be reasonably estimated.

The amount recognized is subject to estimates and management's judgment with respect to the likely outcome of each uncertain tax position. The amount that is ultimately incurred for an individual uncertain tax position or for all uncertain tax positions in the aggregate could differ from the amount recognized.

Although management considers our valuation allowance as of December 31, 2014 and 2013 adequate, material changes in these amounts may occur in the future based on tax audits and changes in legislation.

Recent Accounting Pronouncements

In April 2014, the FASB issued ASU 2014-08 Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. This guidance changes the criteria for reporting discontinued operations while enhancing disclosures in this area. Under the new guidance, only disposals representing a strategic shift in operations should be presented as discontinued operations. Those strategic shifts should have a major effect on the organization's operations and financial results. In addition, the new guidance requires expanded disclosures about discontinued operations that will provide financial statement user with more information about the assets, liabilities, income, and expenses of discontinued operations. This guidance is effective in the first quarter of 2015 for public companies with calendar year ends. The Company does not expect this to impact its operating results, financial position, or cash flows.

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In June 2014, the FASB issued ASU 2014-12 Compensation – Stock Compensation (Topic 718): Accounting for Share-Based Payments When the Terms of an Award Provided That a Performance Target Could Be Achieved after the Requisite Service Period. This guidance requires that a performance target that affects vesting and that could be achieved after the requisite service period be treated as a performance condition. A reporting entity should apply existing guidance in Topic 718, Compensation – Stock Compensation, as it relates to awards with performance conditions that affect vesting to account for such awards. The performance target should not be reflected in estimating the grant-date fair value of the award. Compensation cost should be recognized in the period in which it becomes probable that the performance target will be achieved and should represent the compensation cost attributable to the period(s) for which the requisite service has already been rendered. If the performance target becomes probable of being achieved before the end of the requisite service period, the remaining unrecognized compensation cost should be recognized prospectively over the remaining requisite service period. The total amount of compensation cost recognized during and after the requisite service period should reflect the number of awards that are expected to vest and should be adjusted to reflect those awards that ultimately vest. The requisite service period ends when the employee can cease rendering service and still be eligible to vest in the award if the performance target is achieved. This guidance is effective for annual periods and interim periods within those annual periods beginning after December 15, 2015. Early adoption in permitted. The Company does not expect this to impact its operating results, financial position, or cash flows.

In August 2014, the FASB issued ASU 2014-15 Presentation of Financial Statements – Going Concern (Subtopic 205-40: Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern. This guidance is intended to define management's responsibility to evaluate whether there is substantial doubt about an organization's ability to continue as a going concern and to provide related footnote disclosures. This also provides guidance to a organization's management, with principles and definitions that are intended to reduce diversity in the timing and content of disclosures that are commonly provided by organizations today in the financial statement footnotes. This guidance is effective for annual periods beginning after December 15, 2016 and interim periods within annual periods beginning after December 15, 2016. Early adoption in permitted for annual and interim reporting periods for which the financial statements have not previously been issued. The Company does not expect this to impact its operating results, financial position, or cash flows.

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Contractual Obligations

The following table summarizes the Company’s contractual obligations due by period as of December 31, 2014 (in thousands):

| Contractual Obligations | Total | 2015 | 2016 | 2017 |
|---|---|---|---|---|
| Long-Term Debt Obligations[1] | $889 | $65 | $56 | $768 |
| Operating Lease Obligations | 120 | 48 | 50 | 22 |
| Estimated Interest on Long-Term Debt Obligations | 82 | 36 | 31 | 15 |
| Total | $1,091 | $149 | $137 | $805 |

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISKS

Commodity Risk

The Company’s major market risk exposure is in the pricing applicable to its oil and gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to natural gas production. Historically, prices received for oil and gas production have been volatile and unpredictable and price volatility is expected to continue. Monthly oil price realizations during 2014 ranged from a low of $52.64 per barrel to a high of $98.51 per barrel.

In addition, during 2010, 2011, and 2012 the Company participated in derivative agreements on a specified number of barrels of oil of its production. The Company did not participate in any derivative agreements during 2014 or 2013, but may participate in derivative activities in the future.

Interest Rate Risk

At December 31, 2014, the Company had debt outstanding of approximately $889,000 including, as of that date, $734,000 owed on its credit facility with Prosperity Bank. The interest rate on the credit facility is variable at a rate equal to the prime rate plus 0.50%. This rate was 3.75% at December 31, 2014. The Company’s remaining debt of $155,000 has fixed interest rates ranging from 3.9% to 7.25%. As a result, the Company annual interest cost in 2014 fluctuated based on short-term interest rates on approximately 82.6% of its total debt outstanding at December 31, 2014. During 2014, the Company paid approximately $71,000 of interest on the Prosperity Bank line of credit. The impact on interest expense and the Company’s cash flows of a 10% increase in the interest rate on the Prosperity Bank credit facility would be approximately $3,000 assuming borrowed amounts under the credit facility remained at the same amount owed as of December 31, 2014. The Company did not have any open derivative contracts relating to interest rates at December 31, 2014.

Forward-Looking Statements and Risk

Certain statements in this Report including statements of the future plans, objectives, and expected performance of the Company are forward-looking statements that are dependent upon certain events, risks and uncertainties that may be outside the Company’s control, and which would cause actual results to differ materially from those anticipated. Some of these include, but are not limited to, the market prices of oil and gas, economic and competitive conditions, inflation rates, legislative and regulatory changes, financial market conditions, political and economic uncertainties of foreign governments, future business decisions, and other uncertainties, all of which are difficult to predict.

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[1] The credit facility maturity date of January 27, 2017 is based on the March 16, 2015 amendment to the credit agreement.

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There are numerous uncertainties inherent in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from estimates. The drilling of exploratory wells can involve significant risks, including those related to timing, success rates and cost overruns. Lease and rig availability, complex geology, and other factors can also affect these risks. Additionally, fluctuations in oil and gas prices or prolonged periods of low prices may substantially adversely affect the Company's financial position, results of operations, and cash flows.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The financial statements and supplementary data commence on page F-1.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

The Company's Chief Executive Officer and Chief Financial Officer, and other members of management have evaluated the effectiveness of the Company's disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)). Based on such evaluation, the Company's Chief Executive Officer and Chief Financial Officer have concluded that the Company's disclosure controls and procedures, as of the end of the period covered by this Report, were adequate and effective to provide reasonable assurance that information required to be disclosed by the Company in reports that it files or submits under the Exchange Act, is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms. Michael J. Rugen, the Company's Chief Financial Officer is currently also serving as Company's Chief Executive Officer on an interim basis. Mr. Rugen is acting in both capacities and has executed the accompanying certifications as to both offices.

The effectiveness of a system of disclosure controls and procedures is subject to various inherent limitations, including cost limitations, judgments used in decision making, assumptions about the likelihood of future events, the soundness of internal controls, and fraud. Due to such inherent limitations, there can be no assurance that any system of disclosure controls and procedures will be successful in preventing all errors or fraud, or in making all material information known in a timely manner to the appropriate levels of management.

Managements Annual 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) promulgated under the Securities Exchange Act of 1934. Internal control over financial reporting refers to the process designed by, or under the supervision of the Company's Chief Executive Officer and Chief Financial Officer, and effected by the Company's Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, and includes those policies and procedures that:

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- Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the Company's assets;

- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures are being made only in accordance with authorizations of the Company's management and directors; and

- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the Company's financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness into future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of the Company's management, including the Chief Executive Officer and the Chief Financial Officer, the Company's management conducted an evaluation of the effectiveness of the Company internal control over financial reporting as of December 31, 2014. In making this assessment, the Company's management used the criteria set forth in the framework in "Internal Control-Integrated-Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). This framework was updated in 2013. Based on the evaluation conducted under the framework in "Internal Control- Integrated Framework," issued by COSO the Company's management concluded that the Company's internal control over financial reporting was effective as of December 31, 2014.

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

Changes in Internal Control Over Financial Reporting

As part of a continuing effort to improve the Company's business processes, management is evaluating its internal controls and may update certain controls to accommodate any modifications to its business processes or accounting procedures. During 2014, certain transactions that were previously reviewed by the former CEO and Audit Committee are now performed by a third party accounting group and are reviewed by the CFO. There have been no changes to the Company's system of internal control over financial reporting during the year ended December 31, 2014 that have materially affected, or are reasonably likely to materially affect, the Company's system of controls over financial reporting.

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## ITEM 9B. OTHER INFORMATION

On January 5, 2015, options to purchase 25,000 common shares at $0.25 per share were issued in the aggregate to the Company’s four directors. These options fully vested upon grant date and will expire on January 4, 2020.

On February 19, 2015, in response to the current global market factors affecting revenues from sales of the Company's production of crude oil, the Board of Directors of the Company implemented reductions in the current compensation of the Company's officers. As to the Company's Chief Financial Officer and interim Chief Executive Officer Michael J. Rugen, Mr. Rugen's salary as CFO and bonus as CEO was reduced effective February 2, 2015 by 18% from current levels, or about $42,000 per year. The 18% reduction will remain in place until the market price of crude oil, calculated as a thirty day trailing average of WTI postings as published by the U.S. Energy Information Administration meets or exceeds $70 per barrel when his compensation shall revert to the levels in place before the reductions became effective. At such time, if any, that the market price of crude oil, calculated as a thirty day trailing average of WTI postings as published by the U.S. Energy Information Administration meets or exceeds $85 per barrel, all previous reductions made will be reimbursed to Mr. Rugen if he is still employed by the Company. Mr. Rugen expressly consented to this reduction as not constituting a "termination without Cause" under the terms of his Compensation Agreement dated September 18, 2013 but permitting him to invoke that provision in the event prices do recover as set out above but the compensation reduction is not rescinded or the reductions are not repaid. As to the Company's Vice President, General Counsel, and Corporate Secretary Cary V Sorensen, the Company and Mr. Sorensen reached agreement on February 25, 2015 that as of March 2, 2015 his annual salary would be set at $91,000 per annum, a reduction from his current salary of $137,500 per annum, in consideration of the Company's agreement to permit Mr. Sorensen to serve as a full time employee from a virtual office in Galveston, Texas with presence in the Denver area headquarters as required. He will remain eligible for certain existing benefits: 401-K plan, bonus potential; Company-paid state bar membership dues and charges, and mobile phone charges. The Company also pays reasonable and customary office operating expenses. The Company would pay for business travel on a mileage basis and out of pocket travel costs. However, as to health insurance, Mr. Sorensen will obtain a combination of private/governmental health and disability insurance in lieu of the Company plans, with the Company reimbursing up to $13,000 per year in premiums incurred by him in doing so, resulting in about $9,000 in savings to the Company compared to current insurance premium costs. In addition, Mr. Sorensen's $91,000 salary will be reduced effective March 2, 2015 by 10%. In like manner as set out above for Mr. Rugen, the 10% reduction on Mr. Sorensen's salary will remain in place until the market price of crude oil, calculated as a thirty day trailing average of WTI postings as published by the U.S. Energy Information Administration meets or exceeds $70 per barrel when his salary shall revert to $91,000 per annum. At such time, if any, that the market price of crude oil, calculated as a thirty day trailing average of WTI postings as published by the U.S. Energy Information Administration meets or exceeds $85 per barrel, all previous reductions made from the $91,000 salary level will be reimbursed to Mr. Sorensen if he is still employed by the Company. This agreement is not an employment contract, but does provide that in the event Mr. Sorensen were terminated without cause during the year following, he would receive a severance payment in the amount of six months' salary in effect at time of any such termination.

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On March 16, 2015, the Company’s senior credit facility with Prosperity Bank after Prosperity Bank’s most recent review of the Company’s currently owned producing properties was amended to decrease the Company’s borrowing base from $14.3 million to $7.8 million and extend the term of the facility to January 27, 2017. The borrowing base remains subject to the existing periodic redetermination provisions in the credit facility. The interest rate remained prime plus 0.50% per annum. This rate was 3.75% at the date of the amendment. The maximum line of credit of the Company under the Prosperity Bank credit facility remained $40 million and the Company’s outstanding borrowing under the facility as of March 27, 2015 was approximately $843,000.

# PART III

## ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERANCE

Identification of Directors and Executive Officers

| NAME | POSITIONS HELD | DATE OF INITIAL ELECTION OR DESIGNATION | AGE |
|---|---|---|---|
| Matthew K. Behrent | Director | 03/27/2007 | 44 |
| Hughree F. Brooks | Director | 12/03/2010 | 60 |
| Peter E. Salas | Director;<br>Chairman of the Board | 10/08/2002<br>10/21/2004 | 60 |
| Richard M. Thon | Director | 11/22/2013 | 59 |
| Michael J. Rugen | Chief Financial Officer;<br>Chief Executive Officer (interim) | 09/28/2009<br>06/24/2013 | 54 |
| Cary V. Sorensen | Vice-President; General Counsel; Secretary | 07/09/1999 | 66 |

Business Experience

Directors

Matthew K. Behrent is currently the Executive Vice President, Corporate Development of EDCI Holdings, Inc, a company that is currently engaged in carrying out a plan of dissolution. Before joining EDCI in June, 2005, Mr. Behrent was an investment banker, working as a Vice-President at Revolution Partners, a technology focused investment bank in Boston, from March 2004 until June 2005 and as an associate in Credit Suisse First Boston Corporation's technology mergers and acquisitions group from June 2000 until January 2003. From June 1997 to May 2000, Mr. Behrent practiced law, most recently with Cleary, Gottlieb, Steen & Hamilton in New York, advising financial sponsors and corporate clients in connection with financings and mergers and acquisitions transactions. Mr. Behrent received his J.D. from Stanford Law School in 1997, and his B.A. in Political Science and Political Theory from Hampshire College in 1992. He became a Director of the Company on March 27, 2007. He is also a Director and Chairman of the Audit Committee of Asure Software, Inc. (NASDAQ: ASUR). The experience, qualifications, attributes, and skills gained by Mr. Behrent in these sophisticated legal and financial positions directly apply to and support the financial oversight of the Company’s operations and lead to the conclusion that Mr. Behrent should serve as a Director of the Company.

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Hughree F. Brooks in 2010 co-founded Powerhouse Energy Solutions LLC, a company engaged in providing equipment and services to clients in renewable and alternative energy industries in the United States and abroad. Powerhouse is a provider of solar energy systems as well as advisory services to biofuel producers. Since 1998, Mr. Brooks has continuously provided consulting services in the oil and gas exploration industry. These services include land management, landowner representation, deal structuring and financing, and expert witness services. Mr. Brooks has 35 years of experience as a land manager with independent and major oil companies including Amoco Production, Mitchell Energy, Ladd Petroleum, Phoenix Exploration and Renown Petroleum Inc. His clients own in excess of 16,000 acres in South Louisiana with a long history of oil and gas production. In 2002, he founded and continues to serve as the Executive Director of Friends Of The Farm, a Texas nonprofit. Mr. Brooks is a licensed attorney who received his J.D. from Loyola Law School in 1980. He received a Bachelor of Science Degree in 1976 from Loyola University in New Orleans. The experience, qualifications, and skills of Mr. Brooks gained in an extensive career in the oil and gas exploration and production industry are directly related to the operations of the Company and lead to the conclusion that Mr. Brooks should serve as a Director of the Company.

Peter E. Salas has been President of Dolphin Asset Management Corp. and its related companies since he founded it in 1988. Prior to establishing Dolphin, he was with J.P. Morgan Investment Management, Inc. for ten years, becoming Co-manager, Small Company Fund and Director-Small Cap Research. He received an A.B. degree in Economics from Harvard in 1978. Mr. Salas was elected to the Board of Directors on October 8, 2002. During a portion of the last five years, Mr. Salas also served on the Board of Directors of Southwall Technologies, Inc. and Williams Controls, Inc. The business experience, attributes, and skills gained by Mr. Salas in these sophisticated financial positions, together with his service as director of other public companies and his capacity as controlling person of the Company’s largest shareholder directly apply to and support his qualification as a director, and lead to the conclusion that Mr. Salas should serve as a Director of the Company.

Richard M. Thon began a career with ARAMARK Corporation in 1987. ARAMARK is based in Philadelphia, has 250,000 employees worldwide, and provides food services, facilities management, and uniform and career apparel to health care institutions, universities, and businesses in 22 countries. Mr. Thon served in various capacities in the Corporate Finance Department of ARAMARK culminating with the position of Assistant Treasurer when he retired in June 2002. His responsibilities included bank credit agreements, public debt issuance, interest rate risk management, foreign subsidiary credit agreements, foreign exchange, letters of credit, insurance finance, off-balance-sheet finance, and real estate and equipment leasing. Prior to joining ARAMARK, Mr. Thon was a Vice President in the International Department of Mellon Bank. Since his retirement in 2002, Mr. Thon has served in a variety of volunteer charitable and civic activities. In addition, during a portion of the past five years, he served on the board of ACT Conferencing, Inc. Mr. Thon received a B.A. in Economics degree from Yale College in 1977 and a Masters of Business Administration degree in Finance from The Wharton School, University of Pennsylvania in 1979. Mr. Thon’s experience in the fields of banking and finance directly apply to the business needs of the Company and lead to the conclusion that he will provide significant benefit to the Board and that he is qualified to serve as a Director of the Company.

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Officers

Michael J. Rugen was named Chief Financial Officer of the Company in September 2009 and as interim Chief Executive Officer in June 2013. He is a certified public accountant (Texas) with over 30 years of experience in exploration, production and oilfield service. Prior to joining the Company, Mr. Rugen spent 2 years as Vice President of Accounting and Finance for Nighthawk Oilfield Services. From 2001 to June 2007, he was a Manager/Sr. Manager with UHY Advisors, primarily responsible for managing internal audit and Sarbanes-Oxley 404 engagements for various oil and gas clients. In 1999 and 2000, Mr. Rugen provided finance and accounting consulting services with Jefferson Wells International. From 1982 to 1998, Mr. Rugen held various accounting and management positions at BHP Petroleum, with accounting responsibilities for onshore and offshore US operations as well as operations in Trinidad and Bolivia. Mr. Rugen earned a Bachelor of Science in Accounting in 1982 from Indiana University.

Cary V. Sorensen is a 1976 graduate of the University of Texas School of Law and has undergraduate and graduate degrees from North Texas State University and Catholic University in Washington, D.C. Prior to joining the Company in July 1999, he had been continuously engaged in the practice of law in Houston, Texas relating to the energy industry since 1977, both in private law firms and a corporate law department, serving for seven years as senior counsel with the oil and gas litigation department of a Fortune 100 energy corporation in Houston before entering private practice in June, 1996. He has represented virtually all of the major oil companies headquartered in Houston as well as local distribution companies and electric utilities in a variety of litigated and administrative cases before state and federal courts and agencies in nine states. These matters involved gas contracts, gas marketing, exploration and production disputes involving royalties or operating interests, land titles, oil pipelines and gas pipeline tariff matters at the state and federal levels, and general operation and regulation of interstate and intrastate gas pipelines. He has served as General Counsel of the Company since July 9, 1999.

Family and Other Relationships

There are no family relationships between any of the present directors or executive officers of the Company.

Involvement in Certain Legal Proceedings

To the knowledge of management, no director, executive officer or affiliate of the Company or owner of record or beneficially of more than 5% of the Company's common stock is a party adverse to the Company or has a material interest adverse to the Company in any proceeding.

To the knowledge of management, during the past ten years, unless specifically indicated below with respect to any numbered item, no present director, executive officer or person nominated to become a director or an executive officer of the Company:

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(1) Filed a petition under the federal bankruptcy laws or any state insolvency law, nor had a receiver, fiscal agent or similar officer appointed by a court for the business or property of such person, or any partnership in which he or she was a general partner at or within two years before the time of such filing, or any corporation or business association of which he or she was an executive officer at or within two years before the time of such filing; provided however that the Company's Chief Financial Officer Michael J. Rugen during 2007 through mid 2009 was Vice President of Accounting and Finance for Nighthawk Oilfield Services in Houston, Texas (Nighthawk); Nighthawk filed for bankruptcy protection under Chapter 7 of the bankruptcy laws on July 10, 2009 and such fact was affirmatively disclosed to the Company's Board before Mr. Rugen was appointed to the position of Chief Financial Officer of the Company in September, 2009, and the Board determined that the circumstances surrounding bankruptcy filing did not disclose any reason to question the integrity or qualifications of Mr. Rugen for the position of Chief Financial Officer of the Company.

(2) Was convicted in a criminal proceeding or named the subject of a pending criminal proceeding (excluding traffic violations and other minor offenses);

(3) Was the subject of any order, judgment or decree, not subsequently reversed, suspended or vacated, of any court of competent jurisdiction, permanently or temporarily enjoining him or her from or otherwise limiting the following activities: (a) acting as a futures commission merchant, introducing broker, commodity trading advisor, commodity pool operator, floor broker, leverage transaction merchant, any other person regulated by the Commodity Futures Trading Commission, or an associated person of any of the foregoing, or as an investment adviser, underwriter, broker or dealer in securities, or as an affiliated person, director or employee of any investment company, bank, savings and loan association or insurance company, or engaging in or continuing any conduct or practice in connection with such activity; (b) engaging in any type of business practice; or (c) engaging in any activity in connection with the purchase or sale of any security or commodity or in connection with any violation of federal or state securities laws or federal commodities laws;

(4) Was the subject of any order, judgment or decree, not subsequently reversed, suspended or vacated, of any Federal or State authority barring, suspending or otherwise limiting him or her for more than 60 days from engaging in any activity described in paragraph 3(a) above, or being associated with any persons engaging in any such activity;

(5) Was found by a court of competent jurisdiction in a civil action or by the SEC to have violated any federal or state securities law, and the judgment in such civil action or finding by the SEC has not been subsequently reversed, suspended, or vacated;

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(6) Was found by a court of competent jurisdiction in a civil action or by the Commodity Futures Trading Commission (“CFTC”) to have violated any federal commodities law, and the judgment in such civil action or finding by the CFTC has not been subsequently reversed, suspended, or vacated;

(7) Was the subject of, or a party to, any federal or state judicial or administrative order, judgment, decree, or finding, not subsequently reversed, suspended or vacated, relating to an alleged violation of: (i) any federal or state securities or commodities law or regulation; (ii) any law or regulation respecting financial institutions or insurance companies including but not limited to a temporary or permanent injunction, order of disgorgement or restitution, civil money penalty or temporary or permanent cease and desist order, or removal or prohibition order; or (iii) any law or regulation prohibiting mail or wire fraud or fraud in connection with any business entity; or

(8) Was the subject of, or a party to, any sanction or order, not subsequently reversed, suspended or vacated, of any self-regulatory organization (as defined in Section 3(a)(26) of the Exchange Act [15 U.S.C. 78c(a)(26)], any registered entity (as defined in Section 1(a)(29) of the Commodity Exchange Act [7 U.S.C. 1(a)(29)], or any equivalent exchange, association, entity or organization that has disciplinary authority over its members or persons associated with a member.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires the Company’s executive officers, directors and persons who beneficially own more than 10% of the Company’s common stock to file initial reports of ownership and reports of changes in ownership with the SEC no later than the second business day after the date on which the transaction occurred unless certain exceptions apply. In fiscal 2014, the Company, its officers, directors, and shareholders owning more than 10% of its common stock were not delinquent in filing of any of their Form 3, 4, and 5 reports.

Code of Ethics

The Company’s Board of Directors has adopted a Code of Ethics that applies to the Company’s financial officers and executives officers, including its Chief Executive Officer and Chief Financial Officer. The Company’s Board of Directors has also adopted a Code of Conduct and Ethics for Directors, Officers and Employees. A copy of these codes can be found at the Company’s internet website at www.tengasco.com. The Company intends to disclose any amendments to its Codes of Ethics, and any waiver from a provision of the Code of Ethics granted to the Company’s President, Chief Financial Officer or persons performing similar functions, on the Company’s internet website within five business days following such amendment or waiver. A copy of the Code of Ethics can be obtained free of charge by writing to Cary V. Sorensen, Secretary, Tengasco, Inc., 6021 S. Syracuse Way, Suite 117, Greenwood Village, CO 80111.

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Audit Committee

During 2014, directors Matthew K. Behrent and Richard M. Thon were the members of the Board's Audit Committee. Mr. Behrent was the Chairman of the Committee and the Board of Directors determined that both Mr. Behrent and Mr. Thon were each an "audit committee financial expert" as defined by applicable Securities and Exchange Commission ("SEC") regulations and the NYSE MKT Rules. Each of the members of the Audit Committee met the independence and experience requirements of the NYSE MKT Rules, the applicable Securities Laws, and the regulations and rules promulgated by the SEC. The Audit Committee met each quarter and a total of five (5) times in Fiscal 2014 with the Company's auditors, including discussing the audit of the Company's year-end financial statements.

The Audit Committee adopted an Audit Committee Charter during fiscal 2001. In 2004, the Board adopted an amended Audit Committee Charter, a copy of which is available on the Company's internet website, www.tengasco.com. The Audit Committee Charter fully complies with the requirements of the NYSE MKT Rules. The Audit Committee reviews and reassesses the Audit Committee Charter annually.

The Audit Committee's functions are:

To review with management and the Company's independent auditors the scope of the annual audit and quarterly statements, significant financial reporting issues and judgments made in connection with the preparation of the Company's financial statements;

To review major changes to the Company's auditing and accounting principles and practices suggested by the independent auditors;

To monitor the independent auditor's relationship with the Company;

To advise and assist the Board of Directors in evaluating the independent auditor's examination;

To supervise the Company's financial and accounting organization and financial reporting;

To nominate, for approval of the Board of Directors, a firm of certified public accountants whose duty it is to audit the financial records of the Company for the fiscal year for which it is appointed; and

To review and consider fee arrangements with, and fees charged by, the Company's independent auditors.

Changes in Board Nomination Procedures

In 2014, there were no changes to the procedures adopted by the Board for nominations for the Board of Directors. Those procedures were last set forth in the Company's Proxy Statement filed on October 3, 2014 for the Company's Annual Meeting held on November 14, 2014 and are posted on the Company's internet website at www.tengasco.com. In the event of any such amendment to the procedures, the Company intends to disclose the amendments on the Company's internet website within five business days following such amendment.

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ITEM 11. EXECUTIVE COMPENSATION

Executive Officer Compensation

The following table sets forth a summary of all compensation awarded to, earned or paid to, the Company's Chief Executive Officer, Chief Financial Officer and other executive officers whose compensation exceeded $100,000 during fiscal years ended December 31, 2014 and December 31, 2013.

SUMMARY COMPENSATION TABLE

| Name and Principal Position | Year | Salary ($) | Bonus ($) | Option Awards ($) | All Other Compensation[2] ($) | Total ($) |
|---|---|---|---|---|---|---|
| Michael J. Rugen, | 2014 | 186,716 | 68,343 | - | 53,597 | 308,656 |
| Chief Financial Officer | 2013 | 155,770 | 52,500 | - | 14,828 | 223,098 |
| Chief Executive Officer (interim)[3] | | | | | | |
| Cary V. Sorensen, | 2014 | 137,940 | 5,000 | - | 9,788 | 152,728 |
| General Counsel | 2013 | 137,940 | - | - | 10,221 | 148,161 |
| Jeffrey R. Bailey, | | | | | | |
| Chief Executive Officer (former)[4] | 2013 | 98,500 | 27,000 | - | 6,933 | 132,433 |
| Charles P. McInturff, | | | | | | |
| Vice President[5] | 2013 | 182,970 | - | - | 12,335 | 195,305 |

[2] The amounts in this column consist of the Company’s matching contributions to its 401 (k) plan, personal use of company vehicles, and the portion of company-wide group term life insurance premiums allocable to these named executive officers.

[3] Mr. Rugen was appointed interim Chief Executive Officer on June 28, 2013. The information for Mr. Rugen for 2014 and 2013 includes compensation for his services as both CEO and CFO. The bonus in 2014 and 2013 include $33,068 and $15,000 respectively for quarterly bonuses paid to Mr. Rugen as compensation to serve in the capacity as CEO.

[4] Mr. Bailey resigned as Chief Executive Officer of the Company on June 28, 2013.

[5] Mr. McInturff resigned as Vice President of the Company on December 16, 2013.

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Outstanding Equity Awards at Fiscal Year-End

| Name | OPTION AWARDS Number of securities underlying unexercised options exercisable | Number of securities underlying unexercised options unexercisable | Option exercise price | Option expiration date |
|---|---|---|---|---|
| Michael J. Rugen | 400,000 | - | $ 0.50 | 9/27/2015 |
| Cary V. Sorensen | 74,000 | - | $ 0.44 | 8/29/2015 |

Option and Award Exercises

During 2013, Mr. McInturff received a $59,520 payment in lieu of exercising his fully exercisable options to purchase 400,000 shares. This payment is the same economic benefit to Mr. McInturff as if he had made a cashless exercise of the options, and the Company elected to make such payment in lieu of issuing the shares and the resulting dilutive effect of doing so. These options were to expire on February 1, 2013. No other options were exercised during 2014 or 2013.

Employment Contracts and Compensation Agreements

On September 18, 2013, the Company and its Chief Financial Officer and interim Chief Executive Officer Michael J. Rugen entered into a written Compensation Agreement as reported on Form 8-K filed on September 24, 2013. Under the terms of the Compensation Agreement, Mr. Rugen’s annual salary will increase from $150,000 to $170,000 per year in his capacity as Chief Financial Officer, and he will receive a bonus of $7,500 per quarter for each quarter during which he also serves as interim Chief Executive Officer. At June 1, 2014, Mr. Rugen’s salary was increased to $199,826 per year in his capacity as Chief Financial Officer, the quarterly bonus received while in the capacity as interim Chief Financial Officer was increased to $8,815 per quarter. The increases at June 1, 2014 were for cost of living adjustments related to the relocation of the corporate office from Knoxville to Greenwood Village. The Compensation agreement is not an employment contract, but does provide that in the event Mr. Rugen were terminated without cause, he would receive a severance payment in the amount of six month’s salary in effect at the time of any such termination.

On February 25, 2015, the Company and its Vice President, General Counsel, and Corporate Secretary Cary V. Sorensen entered into a written Compensation Agreement as reported on Form 8-K filed on February 19, 2015. Under the terms of the Compensation Agreement, effective March 2, 2015, Mr. Sorensen’s annual salary will be reduced from $137,500 to $91,000 in consideration of the Company's agreement to permit Mr. Sorensen to serve as a full time employee from a virtual office in Galveston, Texas with presence in the Denver area headquarters as required. He will remain eligible for certain existing benefits: 401-K plan, bonus potential; Company-paid state bar membership dues and charges, and mobile phone charges. The Company also pays reasonable and customary office operating expenses. The Company would pay for business travel on a mileage basis and out of pocket travel costs. However, as to health insurance, Mr. Sorensen will obtain a combination of private/governmental health and disability insurance in lieu of the Company plans, with the Company reimbursing up to $13,000 per year in premiums incurred by him. The Compensation agreement is not an employment contract, but does provide that in the event Mr. Sorensen were terminated without cause, he would receive a severance payment in the amount of six month’s salary in effect at the time of any such termination.

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There are presently no other employment contracts relating to any member of management. However, depending upon the Company's operations and requirements, the Company may offer long-term contracts to executive officers or key employees in the future.

Compensation and Stock Option Committee

The members of the Compensation/Stock Option Committee during 2014 were Matthew K. Behrent, Hughree F. Brooks, and Richard M. Thon, with Mr. Brooks acting as Chairman. Messrs. Behrent, Brooks, and Thon meet the current independence standards established by the NYSE MKT Rules to serve on this Committee.

The Board of Directors has adopted a charter for the Compensation/Stock Option Committee which is available at the Company’s internet website, www.tengasco.com.

The Compensation/Stock Option Committee’s functions, in conjunction with the Board of Directors, are to provide recommendations with respect to general and specific compensation policies and practices of the Company for directors, officers and other employees of the Company. The Compensation/Stock Option Committee expects to periodically review the approach to executive compensation and to make changes as competitive conditions and other circumstances warrant and will seek to ensure the Company's compensation philosophy is consistent with the Company's best interests and is properly implemented. The Committee determines or recommends to the Board of Directors for determination the specific compensation of the Company’s Chief Executive Officer and all of the Company’s other officers. Although the Committee may seek the input of the Company’s Chief Executive Officer in determining the compensation of the Company’s other executive officers, the Chief Executive Officer may not be present during the voting or deliberations with respect to his compensation. The Committee may not delegate any of its responsibilities unless it is to a subcommittee formed by the Committee, but only if such subcommittee consists entirely of directors who meet the independence requirements of the NYSE MKT Rules.

The Compensation/Stock Option Committee is also charged with administering the Tengasco, Inc. Stock Incentive Plan (the “Stock Incentive Plan”). The Compensation/Stock Option Committee has complete discretionary authority with respect to the awarding of options and Stock Appreciation Rights (“SARs”), under the Stock Incentive Plan, including, but not limited to, determining the individuals who shall receive options and SARs; the times when they shall receive them; whether an option shall be an incentive or a non-qualified stock option; whether an SAR shall be granted separately, in tandem with or in addition to an option; the number of shares to be subject to each option and SAR; the term of each option and SAR; the date each option and SAR shall become exercisable; whether an option or SAR shall be exercisable in whole, in part or in installments and the terms relating to such installments; the exercise price of each option and the base price of each SAR; the form of payment of the exercise price; the form of payment by the Company upon the exercise of an SAR; whether to restrict the sale or other disposition of the shares of common stock acquired upon the exercise of an option or SAR; to subject the exercise of all or any portion of an option or SAR to the fulfillment of a contingency, and to determine whether such contingencies have been met; with the consent of the person receiving such option or SAR, to cancel or modify an option or SAR, provided such option or SAR as modified would be permitted to be granted on such date under the terms of the Stock Incentive Plan; and to make all other determinations necessary or advisable for administering the Plan.

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The Compensation/Stock Option Committee met four (4) times in Fiscal 2014. The Committee has the authority to retain a compensation consultant or other advisors to assist it in the evaluation of compensation and has the sole authority to approve the fees and other terms of retention of such consultants and advisors and to terminate their services. The Committee did not retain any such consultants or advisors in 2014.

Compensation of Directors

The Board of Directors has resolved to compensate members of the Board of Directors for attendance at meetings at the rate of $250 per day, together with direct out-of-pocket expenses incurred in attendance at the meetings, including travel. The Directors, as of the date of this Report, have waived all such fees due to them for prior meetings.

Members of the Board of Directors may also be requested to perform consulting or other professional services for the Company from time to time, although at this time no such arrangements are in place. The Board of Directors has reserved to itself the right to review all directors' claims for compensation on an ad hoc basis.

Board members currently receive fees from the Company for their services as director. They may also from time to time be granted stock options under the Tengasco, Inc. Stock Incentive Plan. A separate plan to issue cash and/or shares of stock to independent directors for service on the Board and various committees was authorized by the Board of Directors and approved by the Company’s shareholders. A copy of the Plan is posted at the Company’s website at www.tengasco.com. However, no award was made to any independent director under that separate plan in Fiscal 2014.

DIRECTOR COMPENSATION FOR FISCAL 2014

| Name | Fees earned or paid in cash ($) | Option awards compensation [6] ($) | Total ($) |
|---|---|---|---|
| Matthew K. Behrent | $15,000 | $ 5,464 | $20,464 |
| Hughree F. Brooks | $15,000 | $ 5,464 | $20,464 |
| Richard M. Thon | $15,000 | $ 5,464 | $20,464 |
| Peter E. Salas | $15,000 | $ 5,464 | $20,464 |

[6] The amounts represented in this column are equal to the aggregate grant date fair value of the award computed in accordance with FASB ASC Topic 718, Compensation-Stock Compensation, in connection with options granted under the Tengasco, Inc. Stock Incentive Plan. See Note 13 Stock Options in the Notes to Consolidated Financial Statements included in the Company's Annual Report on Form 10-K for the year ended December 31, 2014 for information on the relevant valuation assumptions.
As of December 31, 2014, Mr. Behrent held 143,750 unexercised options; Mr. Brooks held 93,750 unexercised options; Mr. Salas held 143,750 unexercised options; and Mr. Thon held 25,000 unexercised options.

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ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDERS MATTERS

The following table sets forth the share holdings of those persons who own more than 5% of the Company's common stock as of March 20, 2015 with these computations being based upon 60,842,413 shares of common stock being outstanding as of that date and as to each shareholder, as it may pertain, assumes the exercise of options or warrants granted or held by such shareholder that are exercisable as of March 20, 2015.

FIVE PERCENT STOCKHOLDERS [7]

| Name and Address | Title | Number of Shares Beneficially Owned | Percent of Class |
|---|---|---|---|
| Dolphin Offshore Partners, L.P.<br>c/o Dolphin Mgmt. Services, Inc.<br>P.O. Box 16867<br>Fernandina Beach, FL 32035 | Stockholder | 20,420,652 | 33.6% |
| ICN Fund I, LLC<br>c/o Rodney D. Giles<br>P.O. Box 131420<br>Spring, TX 77393 | Stockholder | 3,112,121 | 5.1% |

[7] Unless otherwise stated, all shares of Common Stock are directly held with sole voting and dispositive power. The shares set forth in the table are as of March 20, 2015.

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SECURITY OWNERSHIP OF DIRECTORS AND OFFICERS

| Name and Address | Title | Number of Shares Beneficially Owned [8] | Percent of Class[9] |
|---|---|---|---|
| Matthew K. Behrent | Director | 158,000[10] | Less than 1% |
| Hughree F. Brooks | Director | 100,000[11] | Less than 1% |
| Michael J. Rugen | Chief Financial Officer | 400,000[12] | Less than 1% |
| Peter E. Salas | Director; Chairman of the Board | 20,763,652[13] | 34.1% |
| Cary V. Sorensen | Vice President; General Counsel; Secretary | 310,226[14] | Less than 1% |
| Richard M. Thon | Director | 31,250[15] | Less than 1% |
| All Officers and Directors as a group | | 21,763,128[16] | 35.3% |

Change in Control

To the knowledge of the Company's management, there are no present arrangements or pledges of the Company's securities which may result in a change in control of the Company.

Equity Compensation Plan Information

The following table sets forth information regarding the Company's equity compensation plans as of December 31, 2014.

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[8] Unless otherwise stated, all shares of common stock are directly held with sole voting and dispositive power. The shares set forth in the table are as of March 20, 2015.
[9] Calculated pursuant to Rule 13d-3(d) under the Securities Exchange Act of 1934 based upon 60,842,413 shares of common stock being outstanding as of March 20, 2015. Shares not outstanding that are subject to options or warrants exercisable by the holder thereof within 60 days of March 20, 2015 are deemed outstanding for the purposes of calculating the number and percentage owned by such stockholder, but not deemed outstanding for the purpose of calculating the percentage of any other person. Unless otherwise noted, all shares listed as beneficially owned by a stockholder are actually outstanding.
[10] Consists of 33,000 shares held directly and vested, fully exercisable options to purchase 125,000 shares.
[11] Consists of vested, fully exercisable options to purchase 100,000 shares.
[12] Consists of vested, fully exercisable options to purchase 400,000 shares.
[13] Consists of directly, vested, fully exercisable options to purchase 125,000 shares, 218,000 shares held individually, and 20,420,652 shares held directly by Dolphin Offshore Partners, L.P. ("Dolphin"). Peter E. Salas is the sole shareholder of and controlling person of Dolphin Mgmt. Services, Inc. which is the general partner of Dolphin.
[14] Consists of 236,226 shares held directly and vested, fully exercisable options to purchase 74,000.
[15] Consists of vested, fully exercisable options to purchase 31,250 shares.

[16] Consists of 487,226 shares held directly by directors and management, 20,420,652 shares held by Dolphin and vested, and fully exercisable options to purchase 855,250 shares.

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| 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[17] | 900,250 | $ 0.57 | 2,674,118 |
| Equity compensation plans not approved by security holders | - | - | - |
| Total | 900,250 | $ 0.57 | 2,674,118 |

## ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

### Certain Transactions

There have been no material transactions, series of similar transactions or currently proposed transactions entered into during 2014 and 2013, to which the Company or any of its subsidiaries was or is to be a party, in which the amount involved exceeds the lesser of $120,000 or one percent of the average of the Company's total assets at year-end for its last two completed fiscal years in which any director or executive officer or any security holder who is known to the Company to own of record or beneficially more than 5% of the Company's common stock, or any member of the immediate family of any of the foregoing persons, had a material interest.

In this Report on Form 10-K for the year ended December 31, 2014, the Company describes three transactions of the type described above, that the Company entered into with Hoactzin in 2007 that remained in existence in 2013 and 2014. As noted above in Item 1, Business, page 9, Peter E. Salas, the Chairman of the Board of Directors of the Company, is the controlling person of Hoactzin and of Dolphin Offshore Partners, L.P., the Company's largest shareholder. These three 2007 transactions between the Company and Hoactzin are described at the following page locations in this Report and in the attached Notes to Consolidated Financial Statements: (1) the Ten Well Program, see Item 1, Business, pages 9 and F-16; (2) the net profits agreement at the Methane Project, see Item 1, Business, pages 13 and F-16; and (3) the Management Agreement, see Item 1, Business, pages 13 and F-17.

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[17] Refers to Tengasco, Inc. Stock Incentive Plan (the "Plan") which was adopted to provide an incentive to key employees, officers, directors and consultants of the Company and its present and future subsidiary corporations, and to offer an additional inducement in obtaining the services of such individuals. The Plan provides for the grant to employees of the Company of "Incentive Stock Options" within the meaning of Section 422 of the Internal Revenue Code of 1986, as amended, nonqualified stock options to outside Directors and consultants the Company and stock appreciation rights. The Plan was approved by the Company's shareholders on June 26, 2001. Initially, the Plan provided for the issuance of a maximum of 1,000,000 shares of the Company's $.001 par value common stock. Thereafter, the Company's Board of Directors adopted and the shareholders approved amendments to the Plan to increase the aggregate number of shares that may be issued under the Plan to 7,000,000 shares. The most recent amendment to the Plan increasing the number of shares that may be issued under the Plan by 3,500,000 shares and

extending the Plan for another 10 years was approved by the Company Board of Directors on February 1, 2008 and approved by the Company's shareholders at the Annual Meeting of Stockholders held June 2, 2008.

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The approximate dollar value of the amount of Hoactzin's interest in each of these three 2007 transactions during each of the years 2014 and 2013 was as follows: (1) Ten Well Program - $148,000 in 2014; $568,000 in 2013 (calculated as the total payments attributable to Hoactzin for its program interest); (2) Net Profits agreement at the Methane Project - $0 in 2014; $0 in 2013 (calculated as the amount of net profits payable to Hoactzin; the project generated no net profits as described in the agreement, and therefore no amount was paid to Hoactzin for net profits, in either 2014 or 2013); and (3) Management Agreement - $0 in 2014; $21,000 in 2013 (calculated as the amount payable by Hoactzin to the Company in reimbursement of one half of the salary and benefits of Patrick McInturff, as manager employed by the Company and excluding all vendor payables, bond premiums, and all other operating costs of Hoactzin's properties, all of which were paid at all times by Hoactzin and not by the Company, in the ordinary course of Hoactzin's ownership and not under the Management Agreement).

In addition to the three 2007 transactions, Hoactzin owns a drilling program interest in the Company's "6 Well Program" in Kansas, acquired in 2005 by Hoactzin in exchange for surrender of the Company's promissory notes given by the Company for borrowings to fund the redemption in 2004 of the Company's three series of preferred stock, all as previously disclosed. Hoactzin's interest in the 6 Well Program was $30,000 in 2014; and $45,000 in 2013 (calculated as the total payments attributable to Hoactzin for its program interest) and is expected to decrease in the future as the wells involved naturally decline in produced volumes.

Director Independence

The Rules of the NYSE MKT (the "NYSE MKT Rules") of which the Company is a member require that an issuer, such as the Company, which is a Smaller Reporting Company pursuant to Regulation S-K Item 10(f)(1), maintain a board of directors of which at least one-half of the members are independent in that they are not officers of the Company and are free of any relationship that would interfere with the exercise of their independent judgment. The NYSE MKT Rules also require that as a Smaller Reporting Company, the Company's Board of Directors' Audit Committee be comprised of at least two members all of whom qualify as independent under the criteria set forth in Rule 10 A-3 of the Securities Exchange Act of 1934 and NYSE MKT Rule 803(b)(2)(c). The Board of Directors has determined that the Company's four directors, Matthew K. Behrent, Hughree F. Brooks, Richard M. Thon, and Peter E. Salas, are independent as defined by the NYSE MKT Rules, and that Matthew K. Behrent, Richard M. Thon, and Hughree F. Brooks are also independent as defined by Section 10A(m)(3) of the Securities Exchange Act of 1934 and the rules and regulations of the Securities and Exchange Commission; and that none of these directors have any relationship which would interfere with the exercise of his independent judgment in carrying out his responsibilities as a director. In reaching its determination, the Board of Directors reviewed certain categorical independence standards to provide assistance in the determination of director independence. The categorical standards are set forth below and provide that a director will not qualify as an independent director under the NYSE MKT Rules if:

The Director is, or has been during the last three years, an employee or an officer of the Company or any of its affiliates;

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The Director has received, or has an immediate family member [18] who has received, during any twelve consecutive months in the last three years any compensation from the Company in excess of $120,000, other than compensation for service on the Board of Directors, compensation to an immediate family member who is an employee of the Company other than an executive officer, compensation received as an interim executive officer or benefits under a tax-qualified retirement plan, or non-discretionary compensation;

The Director is a member of the immediate family of an individual who is, or has been in any of the past three years, employed by the Company or any of its affiliates as an executive officer;

The Director, or an immediate family member, is a partner in, or controlling shareholder or an executive officer of, any for-profit business organization to which the Company made, or received, payments (other than those arising solely from investments in the Company's securities) that exceed 5% of the Company's or business organization's consolidated gross revenues for that year, or $200,000, whichever is more, in any of the past three years;

The Director, or an immediate family member, is employed as an executive officer of another entity where at any time during the most recent three fiscal years any of the Company's executives serve on that entity's compensation committee; or

The Director, or an immediate family member, is a current partner of the Company's outside auditors, or was a partner or employee of the Company's outside auditors who worked on the Company's audit at any time during the past three years.

The following additional categorical standards were employed by the Board in determining whether a director qualified as independent to serve on the Audit Committee and provide that a director will not qualify if:

The Director directly or indirectly accepts any consulting, advisory, or other compensatory fee from the Company or any of its subsidiaries; or

The Director is an affiliated person[19] of the Company or any of its subsidiaries.

The Director participated in the preparation of the Company's financial statements at any time during the past three years.

[18] Under these categorical standards "immediate family member" includes a person's spouse, parents, children, siblings, mother-in-law, father-in-law, brother-in-law, sister-in-law, son-in-law, daughter-in-law, and anyone who resides in such person's home (other than a domestic employee).

[19] For purposes of this categorical standard, an "affiliated person of the Company" means a person that directly or indirectly through intermediaries controls, or is controlled by, or is under common control with the Company. A person will not be considered to be in control of the Company, and therefore not an affiliate of the Company, if he is not the beneficial owner, directly or indirectly of more than 10% of any class of voting securities of the Company and he is not an executive officer of the Company. Executive officers of an affiliate of the Company as well as a director who is also an employee of an affiliate of the Company will be deemed to be affiliates of the Company.

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The independent members of the Board meet as often as necessary to fulfill their responsibilities, but meet at least annually in executive session without the presence of non-independent directors and management.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Audit and Non-Audit Fees

The following table presents the fees for professional audit services rendered by the Company's current independent accountants, Hein & Associates ("Hein"), for the audit of the Company's annual consolidated financial statements and fees for professional audit services rendered for the quarterly reviews for the fiscal years ended December 31, 2014 and December 31, 2013:

AUDIT AND NON-AUDIT FEES

| | 2014 | 2013 |
|---|---|---|
| Audit Fees | $134,316 | $131,275 |
| Audit-Related Fees | - | - |
| Tax Fees | - | - |
| All Other Fees | - | - |
| Total Fees | $134,316 | $131,275 |

Audit fees include fees related to the services rendered in connection with the annual audit of the Company's consolidated financial statements, the quarterly reviews of the Company's quarterly reports on Form 10-Q and the reviews of and other services related to statutory filings or engagements for the subject fiscal years.

Audit-related fees are for assurance and related services by the principal accountants that are reasonably related to the performance of the audit or review of the Company's financial statements.

Tax Fees include services for (i) tax compliance, (ii) tax advice, (iii) tax planning and (iv) tax reporting.

All Other Fees includes fees for all other services provided by the principal accountants not covered in the other categories such as litigation support, etc.

All of the services for 2014 and 2013 were performed by the full-time, permanent employees of Hein.

All of the 2014 services described above were approved by the Audit Committee pursuant to the SEC rule that requires audit committee pre-approval of audit and non-audit services provided by the Company's independent auditors. The Audit Committee considered whether the provisions of such services, including non-audit services, by Hein were compatible with maintaining its independence and concluded they were.

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PART IV.

ITEM 15. EXHIBITS AND FINANCIAL STATEMENTS SCHEDULES

A. The following documents are filed as part of this Report:

1. Financial Statements:

Consolidated Balance Sheets

Consolidated Statements of Operations

Consolidated Statements of Stockholders Equity

Consolidated Statements of Cash Flows

Notes to Consolidated Financial Statements

2. Financial Schedules:

Schedules have been omitted because the information required to be set forth therein is not applicable or is included in the Consolidated Financial Statements or notes thereto.

3. Exhibits.

The following exhibits are filed with, or incorporated by reference into this Report:

Exhibit Index

| Exhibit Number | Description |
|---|---|
| 3.1 | Delaware Certificate of Incorporation (Incorporated by reference to Exhibit B to registrant's Definitive Proxy Statement pursuant to Schedule 14a filed May 2, 2011). |
| 3.2* | Amended and Restated Bylaws as of November 13, 2014 |
| 3.3 | Agreement and Plan of Merger of Tengasco, Inc. (a Tennessee corporation with and into Tengasco, Inc., a Delaware corporation dated as of April 15, 2011 (Incorporated by reference to Exhibit B to registrant's Definitive Proxy Statement pursuant to Schedule 14a filed May 2, 2011). |
| 4.1 | Form of Rights Certificate (Incorporated by reference to registrant's statement on Form S-1 filed February 13, 2004 Reg. File No. 333-109784). |
| 10.1 | Tengasco, Inc. Incentive Stock Plan (Incorporated by reference to Exhibit 4.1 to the registrant's registration statement on Form S-8 filed October 26, 2000). |

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| | |
|---|---|
| 10.2 | Amendment to the Tengasco, Inc. Stock Incentive Plan dated May 19, 2005 (Incorporated by reference to Exhibit 4.2 to the registrant’s registration statement on Form S-8 filed June 3, 2005). |
| 10.3 | Loan and Security Agreement dated as of June 29, 2006 between Tengasco, Inc. and Citibank Texas, N.A. (Incorporated by reference to Exhibit 10.1 to the registrant’s Current Report on Form 8-K dated June 29, 2006). |
| 10.4 | Subscription Agreement of Hoactzin Partners, L.P. for the Company’s ten well drilling program on its Kansas Properties dated August 3, 2007 (Incorporated by reference to Exhibit 10.15 to the registrant’s Annual Report on Form 10-K for the year ended December 31, 2007 filed March 31, 2008 [the “2007 Form 10-K”]). |
| 10.5 | Agreement and Conveyance of Net Profits Interest dated September 17, 2007 between Manufactured Methane Corporation as Grantor and Hoactzin Partners, LP as Grantee (Incorporated by reference to Exhibit 10.16 to the 2007 Form 10-K). |
| 10.6 | Agreement for Conditional Option for Exchange of Net Profits Interest for Convertible Preferred Stock dated September 17, 2007 between Tengasco, Inc., as Grantor and Hoactzin Partners, L.P., as Grantee (Incorporated by reference to Exhibit 10.17 to the 2007 Form 10-K). |
| 10.7 | Assignment of Notes and Liens Dated December 17, 2007 between Citibank, N.A., as Assignor, Sovereign Bank, as Assignee and Tengasco, Inc., Tengasco Land & Mineral Corporation and Tengasco Pipeline Corporation as Debtors (Incorporated by reference to Exhibit 10.18 to the 2007 Form 10-K). |
| 10.8 | Management Agreement dated December 18, 2007 between Tengasco, Inc. and Hoactzin Partners, L.P. (Incorporated by reference to Exhibit 10.20 to the 2007 Form 10-K). |
| 10.9 | Amendment to the Tengasco, Inc. Stock Incentive Plan dated February 1, 2008, 2008 (Incorporated by reference to Exhibit 4.1 to the registrant’s registration statement on Form S-8 filed June 3, 2008). |
| 10.10 | Assignment of Credit Facility to F&M Bank and Trust Company (Incorporated by reference to Exhibit 10.15 to the registrant’s Annual Report on Form 10-K for the year ended December 31, 2010 filed on March 31, 2011). |
| 10.11 | Ninth Amendment to Loan and Security Agreement dated February 22, 2011 between Tengasco, Inc. as borrower and F&M Bank & Trust Company as Lender (Incorporated by reference to Exhibit 9.01 to the registrant’s Current Report on Form 8-K filed on February 25, 2011). |
| 10.12 | Tenth Amendment to Loan and Security Agreement dated March 14, 2012 between Tengasco, Inc. as borrower and F&M Bank & Trust Company as Lender. (Incorporated by reference to Exhibit 10.17 to the registrant’s Annual Report on Form 10-K for the year ended December 31, 2012 filed on March 29, 2013) |
| 10.13 | Eleventh Amendment to Loan and Security Agreement dated September 12, 2012 between Tengasco, Inc. as borrower and F&M Bank & Trust Company as Lender (Incorporated by reference to Exhibit 10.18 to the registrant’s Annual Report on Form 10-K for the year ended December 31, 2012 filed on March 29, 2013). |

| | |
|---|---|
| 10.14 | Twelfth Amendment to Loan and Security Agreement dated January 29, 2013 between Tengasco, Inc. as borrower and F&M Bank & Trust Company as Lender (Incorporated by reference to Exhibit 10.19 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2012 filed on March 29, 2013). |
| 10.15 | Thirteenth Amendment to Loan and Security Agreement dated March 6, 2013 between Tengasco, Inc. as borrower and F&M Bank & Trust Company as Lender (Incorporated by reference to Exhibit 10.20 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2012 filed on March 29, 2013). |
| 10.16 | Fourteenth Amendment to Loan and Security Agreement dated October 24, 2013 between Tengasco, Inc. as borrower and F&M Bank & Trust Company as Lender (Incorporated by reference to Exhibit 10.16 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2013 filed on March 31, 2014). |
| 10.17 | Fifteenth Amendment to Loan and Security Agreement dated March 17, 2014 between Tengasco, Inc. as borrower and F&M Bank & Trust Company as Lender (Incorporated by reference to Exhibit 10.17 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2013 filed on March 31, 2014). |
| 10.18* | Sixteenth Amendment to Loan and Security Agreement dated September 23, 2014 between Tengasco, Inc. as borrower and Prosperity Bank as Lender |
| 10.19* | Seventeenth Amendment to Loan and Security Agreement dated March 16, 2015 between Tengasco, Inc. as borrower and Prosperity Bank as Lender |
| 10.20* | Agreement of Compensation between Tengasco, Inc. and Cary V. Sorensen as Vice President, General Counsel, and Corporate Secretary dated February 25, 2015 |
| 14 | Code of Ethics (Incorporated by reference to Exhibit 14 to the registrant's Annual Report on Form 10-K filed March 30, 2004). |
| 21 | List of subsidiaries (Incorporated by reference to Exhibit 21 to the 2007 Form 10-K). |
| 23.1* | Consent of LaRoche Petroleum Consultants, Ltd. |
| 31* | Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 |
| 32* | Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |
| 99.1* | Report of LaRoche Petroleum Consultants, Ltd. has been added to the filing for the year ended December, 31, 2014 |
| 101.INS* | XBRL Instance Document |
| 101.SCH* | XBRL Taxonomy Extension Schema Document |
| 101.CAL* | XBRL Taxonomy Calculation Linkbase Document |
| 101.DEF* | XBRL Taxonomy Definition Linkbase Document |
| 101.LAB* | XBRL Taxonomy Label Linkbase Document |

101.PRE* XBRLTaxonomy Presentation Linkbase Document

* Exhibit filed with this Report

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SIGNATURES

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

Dated: March 30, 2015

Tengasco, Inc.

(Registrant)

By: s/ Michael J. Rugen
Michael J. Rugen,
Chief Executive Officer
Principal Financial and Accounting Officer

Pursuant to the requirements of the Securities and Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in their capacities and on the dates indicated.

| Signature | Title | Date |
|---|---|---|
| s/ Matthew K. Behrent<br>Matthew K. Behrent | Director | March 30, 2015 |
| s/ Hughree F. Brooks<br>Hughree F. Brooks | Director | March 30, 2015 |
| s/ Peter E. Salas<br>Peter E. Salas | Director | March 30, 2015 |
| s/ Richard M. Thon<br>Richard M. Thon | Director | March 30, 2015 |
| s/ Michael J. Rugen<br>Michael J. Rugen | Chief Executive Officer and<br>Principal Financial Accounting Officer | March 30, 2015 |

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Tengasco, Inc.
and Subsidiaries

Consolidated Financial Statements
Years Ended December 31, 2014, 2013, and 2012

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Tengasco, Inc.

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

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Tengasco, Inc. and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for the years then ended, in conformity with U.S. generally accepted accounting principles.

s/ Hein & Associates LLP

Denver, Colorado
March 30, 2015

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Tengasco, Inc. and Subsidiaries
Consolidated Balance Sheets
(In thousands, except per share and share data)

| | December 31, 2014 | 2013 |
|---|---|---|
| Assets | | |
| Current | | |
| Cash and cash equivalents | $35 | $54 |
| Accounts receivable, less allowance for doubtful accounts of $14 and $0 | 877 | 1,285 |
| Accounts receivable-related party, less allowance for doubtful accounts of $159 and $257 | - | 168 |
| Inventory | 804 | 1,253 |
| Deferred tax asset - current | 68 | 130 |
| Other current assets | 311 | 312 |
| Total current assets | 2,095 | 3,202 |
| Restricted cash | 386 | 507 |
| Loan fees, net | 18 | 35 |
| Oil and gas properties, net (full cost accounting method) | 25,413 | 24,123 |
| Manufactured Methane facilities, net | 1,634 | 4,389 |
| Other property and equipment, net | 200 | 247 |
| Deferred tax asset - noncurrent | 7,283 | 7,209 |
| Total assets | $37,029 | $39,712 |

See accompanying Notes to Consolidated Financial Statements

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Tengasco, Inc. and Subsidiaries
Consolidated Balance Sheets
(In thousands, except per share and share data)

| | December 31, 2014 | December 31, 2013 |
|---|---|---|
| Liabilities and Stockholders' Equity | | |
| Current liabilities | | |
| Accounts payable – trade | $455 | $367 |
| Accounts payable – other | 159 | 327 |
| Accounts payable – related party | 590 | 412 |
| Accrued liabilities | 759 | 444 |
| Current maturities of long-term debt | 65 | 82 |
| Total current liabilities | 2,028 | 1,632 |
| Asset retirement obligation | 2,008 | 1,780 |
| Long term debt, less current maturities | 824 | 3,375 |
| Total liabilities | 4,860 | 6,787 |
| Commitments and contingencies (Note 9) | | |
| Stockholders' equity | | |
| Common stock, $.001 par value: authorized 100,000,000 Shares; 60,842,413 shares issued and outstanding | 61 | 61 |
| Additional paid in capital | 55,703 | 55,671 |
| Accumulated deficit | (23,595) | (22,807) |
| Total stockholders' equity | 32,169 | 32,925 |
| Total liabilities and stockholders' equity | $37,029 | $39,712 |

See accompanying Notes to Consolidated Financial Statements

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Tengasco, Inc. and Subsidiaries
Consolidated Statements of Operations
(In thousands, except per share and share data)

| | Year ended December 31, 2014 | 2013 | 2012 |
|---|---|---|---|
| Revenues | $13,788 | $15,700 | $20,557 |
| Cost and expenses | | | |
| Production costs and taxes | 5,994 | 5,524 | 7,182 |
| Depreciation, depletion, and amortization | 3,030 | 2,912 | 3,403 |
| General and administrative | 2,707 | 2,059 | 2,613 |
| Impairment | 2,796 | - | - |
| Total cost and expenses | 14,527 | 10,495 | 13,198 |
| Income (loss) from operations | (739) | 5,205 | 7,359 |
| Other income (expense) | | | |
| Net interest expense | (88) | (357) | (743) |
| (Loss) on derivatives | - | - | (142) |
| Gain on sale of assets | 33 | 118 | 83 |
| Total other (expense) | (55) | (239) | (802) |
| Income (loss) from continuing operations before income tax | (794) | 4,966 | 6,557 |
| Deferred income tax expense | 12 | (1,915) | (2,226) |
| Current income tax expense | (6) | (95) | (87) |
| Net income (loss) from continuing operations | $(788) | $2,956 | $4,244 |
| (Loss) from discontinued operations, net of income tax benefit | $- | $(137) | $(4,311) |
| Net income (loss) | $(788) | $2,819 | $(67) |
| Net income (loss) per share - Basic | | | |
| Net income (loss) from continuing operations | $(0.01) | $0.05 | $0.07 |
| Net loss from discontinued operations | - | $(0.00) | $(0.07) |
| Net income (loss) per share - Diluted | | | |
| Net income (loss) from continuing operations | $(0.01) | $0.05 | $0.07 |
| Net loss from discontinued operations | - | $(0.00) | $(0.07) |
| Shares used in computing earnings per share | | | |
| Basic | 60,842,413 | 60,842,413 | 60,778,356 |
| Diluted | 60,849,931 | 60,919,878 | 61,154,631 |

See accompanying Notes to Consolidated Financial Statements

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Tengasco, Inc. and Subsidiaries
Consolidated Statements of Stockholders' Equity
(In thousands, except per share and share data)

| | Common Stock | | Paid-in Capital | Accumulated Deficit | Total |
|---|---|---|---|---|---|
| | Shares | Amount | | | |
| Balance, December 31, 2011 | 60,737,413 | $ 61 | $55,595 | $ (25,559) | $30,097 |
| Net loss | - | - | - | (67) | (67) |
| Options and compensation expense | - | - | 52 | - | 52 |
| Common stock issued for exercise of options | 105,000 | - | 52 | - | 52 |
| Balance, December 31, 2012 | 60,842,413 | $ 61 | $55,699 | $ (25,626) | $30,134 |
| Net income | - | - | - | 2,819 | 2,819 |
| Options and compensation expense | - | - | (28) | - | (28) |
| Common stock issued for exercise of options | - | - | - | - | - |
| Balance, December 31, 2013 | 60,842,413 | $ 61 | $55,671 | $ (22,807) | $32,925 |
| Net loss | - | - | - | (788) | (788) |
| Options and compensation expense | - | - | 32 | - | 32 |
| Balance, December 31, 2014 | 60,842,413 | $ 61 | $55,703 | $ (23,595) | $32,169 |

See accompanying Notes to Consolidated Financial Statements

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Tengasco, Inc. and Subsidiaries
Consolidated Statements of Cash Flows
(In thousands)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Operating activities | | | |
| Net income (loss) from continuing operations | $(788) | $2,956 | $4,244 |
| Adjustments to reconcile net income to net cash provided by operating activities | | | |
| Depreciation, depletion, and amortization | 3,030 | 2,912 | 3,403 |
| Amortization of loan fees-interest expenses | 17 | 32 | 55 |
| Accretion of discount on asset retirement obligation | 114 | 120 | 132 |
| Impairment | 2,796 | - | - |
| Gain on sale of vehicles/equipment | (33) | (118) | (83) |
| Compensation and services paid in stock options / equipment | 32 | 50 | 52 |
| Deferred income tax expense | (12) | 1,915 | 2,226 |
| Loss on derivatives | - | - | 142 |
| Allowance for doubtful accounts | - | (84) | 257 |
| Changes in assets and liabilities | | | |
| Restricted cash | 121 | - | (386) |
| Accounts receivable | 576 | 307 | (89) |
| Inventory and other assets | 450 | 31 | (694) |
| Accounts payable | 58 | 103 | 196 |
| Accrued liabilities | 323 | (184) | (95) |
| Settlement on asset retirement obligations | (113) | (69) | (52) |
| Net cash provided by operating activities – continuing operations | 6,571 | 7,971 | 9,308 |
| Net cash (used in) in operating activities – discontinued operations | - | (85) | (265) |
| Net cash provided by operating activities | 6,571 | 7,886 | 9,043 |
| Investing activities | | | |
| Net additions to oil and gas properties | (3,708) | (2,314) | (8,116) |
| Additions to Manufactured Methane facilities | (282) | (2) | (464) |
| Section 1603 refund – Manufactured Methane facilities | - | - | 1,000 |
| Additions to other property & equipment | (21) | (8) | (15) |
| Proceeds from sale of other property & equipment | 17 | 106 | 22 |
| Net cash (used in) investing activities – continuing operations | (3,994) | (2,218) | (7,573) |
| Net cash provided by investing activities – discontinued operations | - | 1,395 | - |
| Net cash (used in) investing activities | (3,994) | (823) | (7,573) |
| Financing activities | | | |
| Proceeds from exercise of options/warrants | - | - | 52 |
| Payment in lieu of exercise of options/warrants | - | (60) | - |
| Proceeds from borrowings | 7,709 | 7,946 | 18,339 |
| Repayment of borrowings | (10,305) | (13,606) | (20,133) |
| Loan fees | - | (10) | (30) |
| Net cash provided by (used in) financing activities – continuing operations | (2,596) | (5,730) | (1,772) |
| Net cash provided by (used in) financing activities – discontinued operations | - | (1,310) | 265 |
| Net cash provided by (used in) financing activities | (2,596) | (7,040) | (1,507) |
| | | | |
| Net change in cash and cash equivalents – continuing operations | (19) | 23 | (37) |
| Cash and cash equivalents, beginning of period | 54 | 31 | 68 |
| Cash and cash equivalents, end of period | $35 | $54 | $31 |

| | | | |
|---|---|---|---|
| Supplemental cash flow information: | | | |
| Cash interest payments | $71 | $325 | $688 |
| Cash paid for taxes | $- | $38 | $67 |
| Supplemental non-cash investing and financing activities: | | | |
| Financed company vehicles | $47 | $188 | $175 |
| Asset retirement obligations incurred | $46 | $26 | $92 |
| Revisions to asset retirement obligations | $138 | $(48 ) | $- |
| Capital expenditures included in accounts payable and accrued liabilities | $207 | $175 | $- |

See accompanying Notes to Consolidated Financial Statements

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Tengasco, Inc. and Subsidiaries
Notes to Consolidated Financial Statements

1. Description of Business and Significant Accounting Policies

Tengasco, Inc. (the "Company") is a Delaware corporation. The Company is in the business of exploration for and production of oil and natural gas. The Company's primary area of oil exploration and production is in Kansas. The Company's primary area of natural gas exploration and production has been the Swan Creek Field in Tennessee. The Company sold all of its oil and gas leases and producing assets in Tennessee on August 16, 2013.

The Company's wholly-owned subsidiary, Tengasco Pipeline Corporation, owned and operated a 65 mile intrastate pipeline which it constructed to transport natural gas from the Company's Swan Creek Field to customers in Kingsport, Tennessee. As the Company had entered into an agreement to sell the pipeline asset, it had been classified as "Assets held for sale" in the Consolidated Balance Sheet as of December 31, 2012 and the related results of operations have been classified as "(Loss) from discontinued operations, net of income tax benefit" in the Consolidated Statement of Operations for the years ended December 31, 2013, 2012, and 2011. The Company sold of all its pipeline related assets on August 16, 2013. (See Note 7. Assets Held for Sale and Discontinued Operations)

The Company's wholly-owned subsidiary, Manufactured Methane Corporation ("MMC") operates treatment and delivery facilities for the extraction of methane gas from nonconventional sources for eventual sale to natural gas and electricity customers.

Principles of Consolidation

The accompanying consolidated financial statements are presented in accordance with accounting principles generally accepted in the United States ("U.S. GAAP"). The consolidated financial statements include the accounts of the Company, and its wholly-owned subsidiaries after elimination of all significant intercompany transactions and balances.

Use of Estimates

The accompanying consolidated financial statements are prepared in conformity with U.S. GAAP which require management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the dates of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Significant estimates include reserve quantities and estimated future cash flows associated with proved reserves, which significantly impact depletion expense and potential impairments of oil and natural gas properties, income taxes and the valuation of deferred tax assets, stock-based compensation and commitments and contingencies. We analyze our estimates based on historical experience and various other assumptions that we believe to be reasonable. While we believe that our estimates and assumptions used in preparation of the consolidated financial statements are appropriate, actual results could differ from those estimates.

Revenue Recognition

Revenues are recognized based on actual volumes of oil, natural gas, methane gas, and electricity sold to purchasers at a fixed or determinable price, when delivery has occurred and title has transferred, and collectability is reasonably assured. Crude oil is stored and at the time of delivery to the purchasers, revenues are recognized. There were no material natural gas imbalances at December 31, 2014, 2013 or 2012. Methane gas and electricity sales meters are located at the Carter Valley landfill site and sales of electricity are billed each month. No methane gas was sold during 2014.

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Tengasco, Inc. and Subsidiaries
Notes to Consolidated Financial Statements

Cash and Cash Equivalents

Cash and cash equivalents include temporary cash investments with a maturity of ninety days or less at date of purchase.  The Company has elected to enter into a sweep account arrangement allowing excess cash balances to be used to temporarily pay down the credit facility, thereby, reducing overall interest cost.

Restricted Cash

As security required by Tennessee oil and gas regulations, the Company placed $120,500 in a Certificate of Deposit to cover future asset retirement obligations for the Company's Tennessee wells.  At December 31, 2013, this amount was recorded in the Consolidated Balance Sheets under "Restricted cash".  On August 11, 2014, the State of Tennessee notified the holder of the Certificate of Deposit that the Company had fulfilled its obligations to the State with regard to future asset retirement obligations and therefore the Certificate of Deposit could be released.  The Company received these funds from the holder of the Certificate of Deposit in September 2014.  In addition, during the 4th quarter of 2012, the Company placed $386,000 as collateral for a bond with RLI Insurance Company to appeal a civil penalty related to issuance of an "Incident of Non-Compliance" by the Bureau of Safety and Environmental Enforcement ("BSEE") concerning one of the Hoactzin properties operated by the Company pursuant to the Management Agreement (see Note 4).  At December 31, 2014 and 2013, this amount was recorded in the Consolidated Balance Sheets under "Restricted cash" (see Note 11).

Inventory

Inventory consists of crude oil in tanks and is carried at lower of cost or market value.  The cost component of the oil inventory is calculated using the average per barrel cost which includes production costs and taxes, allocated general and administrative costs, and allocated interest cost.  The market component is calculated using the average December oil sales price for the Company's Kansas properties.  In addition, the Company also carried equipment and materials to be used in its Kansas operation and is carried at the lower of cost or market value.  The cost component of the equipment and materials inventory represents the original cost paid for the equipment and materials.  The market component is based on estimated sales value for similar equipment and materials at the end of each year.  At December 31, 2014 and 2013, inventory consisted of the following (in thousands):

| | December 31, 2014 | December 31, 2013 |
|---|---|---|
| Oil – carried at lower of cost or market | $ 573 | $ 765 |
| Equipment and materials – carried at cost | 231 | 488 |
| Total inventory | $ 804 | $ 1,253 |

Oil and Gas Properties

The Company follows the full cost method of accounting for oil and gas property acquisition, exploration, and development activities. Under this method, all costs incurred in connection with acquisition, exploration, and development of oil and gas reserves are capitalized. Capitalized costs include lease acquisitions, seismic related costs, certain internal exploration costs, drilling, completion, and estimated asset retirement costs. The capitalized costs of oil and gas properties, plus estimated future development costs relating to proved reserves and estimated asset retirement costs which are not already included net of estimated salvage value, are amortized on the unit-of-production method based on total proved reserves. The Company has determined its reserves based upon reserve reports provided by LaRoche Petroleum Consultants Ltd. since 2009. The costs of unproved properties are excluded from amortization until the properties are evaluated, subject to an annual assessment of whether impairment has occurred. The Company had $462,000 and $736,000 in unevaluated properties as of December 31, 2014 and 2013, respectively. Proceeds from the sale of oil and gas properties are accounted for as reductions to capitalized costs unless such sales cause a significant change in the relationship between costs and the estimated value of proved reserves, in which case a gain or loss is recognized.

At the end of each reporting period, the Company performs a “ceiling test” on the value of the net capitalized cost of oil and gas properties. This test compares the net capitalized cost (capitalized cost of oil and gas properties, net of accumulated depreciation, depletion and amortization and related deferred income taxes) to the present value of estimated future net revenues from oil and gas properties using an average price (arithmetic average of the beginning of month prices for the prior 12 months) and current cost discounted at 10% plus cost of properties not being amortized and the lower of cost or estimated fair value of unproven properties included in the cost being amortized (ceiling). If the net capitalized cost is greater than the ceiling, a write-down or impairment is required. A write-down of the carrying value of the asset is a non-cash charge that reduces earnings in the current period. Once incurred, a write-down may not be reversed in a later period.

Asset Retirement Obligation

An asset retirement obligation associated with the retirement of a tangible long-lived asset is recognized as a liability in the period incurred, with an associated increase in the carrying amount of the related long-lived asset, our oil and natural gas properties. The cost of the tangible asset, including the asset retirement cost, is depleted over the useful life of the asset. The asset retirement obligation is recorded at its estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligation discounted at our credit-adjusted risk-free interest rate. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value. Accretion expense is recorded as “Production costs and taxes” in the Consolidated Statements of Operations. If the estimated future cost of the asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the long-lived asset. Revisions to estimated asset retirement obligations can result from changes in retirement cost estimates, revisions to estimated inflation rates, and changes in the estimated timing of abandonment.

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Notes to Consolidated Financial Statements

Manufactured Methane Facilities

The Manufactured Methane facilities were placed into service in April 2009 and are being depreciated using the straight-line method over the useful life based on the estimated landfill closure date of December 2041.

Other Property and Equipment

Other property and equipment is carried at cost. The Company provides for depreciation of other property and equipment using the straight-line method over the estimated useful lives of the assets which range from two to seven years. Net gains or losses on other property and equipment disposed of are included in operating income in the period in which the transaction occurs.

Stock-Based Compensation

The Company records stock-based compensation to employees based on the estimated fair value of the award at grant date. We recognize expense on a straight line basis over the requisite service period. For stock-based compensation that vests immediately, the Company recognizes the entire expense in the quarter in which the stock-based compensation is granted. The Company recorded compensation expense of $32,000 in 2014, $(28,000) in 2013, and $52,000 in 2012. Compensation expense in 2013 was impacted by a reversal of $59,500 previously recognized as compensation expense.

Accounts Receivable

Accounts receivable consist of uncollateralized joint interest owner obligations due within 30 days of the invoice date, uncollateralized accrued revenues due under normal trade terms, generally requiring payment within 30 days of production, and other miscellaneous receivables. No interest is charged on past-due balances. Payments made on accounts receivable are applied to the earliest unpaid items. We review accounts receivable periodically and reduce the carrying amount by a valuation allowance that reflects our best estimate of the amount that may not be collectible. An allowance was recorded at December 31, 2014 and 2013. At December 31, 2014 and 2013, accounts receivable consisted of the following (in thousands):

| | December 31, 2014 | December 31, 2013 |
|---|---|---|
| Revenue | $ 845 | $ 1,179 |
| Joint interest | 24 | 35 |
| Other | 22 | 85 |
| Allowance for doubtful accounts | (14) | (14) |
| Total accounts receivable | $ 877 | $ 1,285 |

Income Taxes

Income taxes are reported in accordance with U.S. GAAP, which requires the establishment of deferred tax accounts for all temporary differences between the financial reporting and tax bases of assets and liabilities, using currently enacted federal and state income tax rates. In addition, deferred tax accounts must be adjusted to reflect new rates if enacted into law.

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At December 31, 2014, federal net operating loss carryforwards amounted to approximately $20.2 million which expire between 2019 and 2031. The total deferred tax asset was $7.35 million and $7.34 million at December 31, 2014 and 2013, respectively.

Realization of deferred tax assets is contingent on the generation of future taxable income. As a result, management considers whether it is more likely than not that all or a portion of such assets will be realized during periods when they are available, and if not, management provides a valuation allowance for amounts not likely to be recognized.

Management periodically evaluates tax reporting methods to determine if any uncertain tax positions exist that would require the establishment of a loss contingency. A loss contingency would be recognized if it were probable that a liability has been incurred as of the date of the financial statements and the amount of the loss can be reasonably estimated.

The amount recognized is subject to estimates and management's judgment with respect to the likely outcome of each uncertain tax position. The amount that is ultimately incurred for an individual uncertain tax position or for all uncertain tax positions in the aggregate could differ from the amount recognized.

Although management considers our valuation allowance as of December 31, 2014 and 2013 adequate, material changes in these amounts may occur in the future based on tax audits and changes in legislation.

Concentration of Credit Risk

Financial instruments which potentially subject the Company to concentrations of credit risk consist principally of cash and accounts receivable. Cash and cash equivalents are maintained at financial institutions and, at times, balances may exceed federally insured limits. We have never experienced any losses related to these balances.

The Company's primary business activities include oil and electricity sales to a limited number of customers in the states of Kansas and Tennessee. The related trade receivables subject the Company to a concentration of credit risk.

The Company sells a majority of its crude oil primarily to two customers in Kansas. In addition, the Company sells the electricity generated at the Carter Valley landfill site to a local utility. Although management believes that customers could be replaced in the ordinary course of business, if the present customers were to discontinue business with the Company, it may have a significant adverse effect on the Company's projected results of operations.

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Revenue from the top three purchasers accounted for 79.3%, 16.5%, and 3.8% of total revenues for year ended December 31, 2014. Revenue from the top three purchasers accounted for 79.8%, 14.9%, and 1.7% of total revenues for year ended December 31, 2013. Revenue from the top three purchasers accounted for 79.9%, 14.3% and 2.2% of total revenues for the year ended December 31, 2012. As of December 31, 2014 and 2013, two of our oil purchasers accounted for 84.5% and 92.6%, respectively of our accounts receivable, of which one oil purchaser accounted for 67.8% and 80.7%, respectively.

Earnings per Common Share

We report basic earnings per common share, which excludes the effect of potentially dilutive securities, and diluted earnings per common share which include the effect of all potentially dilutive securities unless their impact is anti-dilutive. The following are reconciliations of the numerators and denominators of our basic and diluted earnings per share, (in thousands except for share and per share amounts):

| | For the years ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Income (numerator): | | | |
| Net income (loss) from continuing operations | $(788) | $2,956 | $4,244 |
| Net loss from discontinued operations | - | $(137) | $(4,311) |
| Weighted average shares (denominator): | | | |
| Weighted average shares - basic | 60,842,413 | 60,842,413 | 60,778,356 |
| Dilution effect of share-based compensation, treasury method | 7,518 | 77,465 | 376,275 |
| Weighted average shares - dilutive | 60,849,931 | 60,919,878 | 61,154,631 |
| Earnings (loss) per share – Basic and Dilutive: | | | |
| Continuing Operations | $(0.01) | $0.05 | $0.07 |
| Discontinued Operations | - | $(0.00) | $(0.07) |

Fair Value of Financial Instruments

The carrying amounts of financial instruments including cash and cash equivalents, accounts receivable, accounts payables, accrued liabilities and long term debt approximates fair value as of December 31, 2014 and 2013.

Derivative Financial Instruments

The Company uses derivative instruments to manage our exposure to commodity price risk on sales of oil production. The Company does not enter into derivative instruments for speculative trading purposes. The Company presents the fair value of derivative contracts on a net basis where the right to offset is provided for in our counterparty agreements. As of December 31, 2014 and 2013, the Company did not have any open derivatives.

Reclassifications

Certain prior year amounts have been reclassified to conform to current year presentation with no effect on net income.

Discontinued Operations

During 2012, the Company committed to a plan to sell the Swan Creek and Pipeline assets. On March 1, 2013, the Company entered into an agreement to sell the Company's Swan Creek and Pipeline assets for $1.5 million. Closing of this transaction occurred on August 16, 2013. The related results of operations have been classified as "(Loss) from discontinued operations, net of income tax benefit" in the Consolidated Statements of Operations for the years ended December 31, 2013 and 2012. The related cash flows have been classified as "Net cash (used in) operating activities – discontinued operations", "Net cash (used in) investing activities – discontinued operations", and Net cash (used in) financing activities – discontinued operations".

As the Swan Creek oil and gas assets represented only a small portion of the Company's full cost pool, these assets remained in oil and gas properties and the gain or loss on the sale was recorded against the full cost pool. Until these properties were sold in August 2013, the related operations were classified in continuing operations. (See Note 7. Assets Held for Sale and Discontinued Operations)

2. Recent Accounting Pronouncements

In April 2014, the FASB issued ASU 2014-08 Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. This guidance changes the criteria for reporting discontinued operations while enhancing disclosures in this area. Under the new guidance, only disposals representing a strategic shift in operations should be presented as discontinued operations. Those strategic shifts should have a major effect on the organization's operations and financial results. In addition, the new guidance requires expanded disclosures about discontinued operations that will provide financial statement user with more information about the assets, liabilities, income, and expenses of discontinued operations. This guidance is effective in the first quarter of 2015 for public companies with calendar year ends. The Company does not expect this to impact its operating results, financial position, or cash flows.

In June 2014, the FASB issued ASU 2014-12 Compensation – Stock Compensation (Topic 718): Accounting for Share-Based Payments When the Terms of an Award Provided That a Performance Target Could Be Achieved after the Requisite Service Period. This guidance requires that a performance target that affects vesting and that could be achieved after the requisite service period be treated as a performance condition. A reporting entity should apply existing guidance in Topic 718, Compensation – Stock Compensation, as it relates to awards with performance conditions that affect vesting to account for such awards. The performance target should not be reflected in estimating the grant-date fair value of the award. Compensation cost should be recognized in the period in which it becomes probable that the performance target will be achieved and should represent the compensation cost attributable to the period(s) for which the requisite service has already been rendered. If the performance target becomes probable of being achieved before the end of the requisite service period, the remaining unrecognized compensation cost should be recognized prospectively over the remaining requisite service period. The total amount of compensation cost recognized during and after the requisite service period should reflect the number of awards that are expected to vest and should be adjusted to reflect those awards that ultimately vest. The requisite service period ends when the employee can cease rendering service and still be eligible to vest in the award if the performance target is achieved. This guidance is effective for annual periods and interim periods within those annual periods beginning after

December 15, 2015.  Early adoption in permitted.  The Company does not expect this to impact its operating results, financial position, or cash flows.

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In August 2014, the FASB issued ASU 2014-15 Presentation of Financial Statements – Going Concern (Subtopic 205-40: Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern. This guidance is intended to define management's responsibility to evaluate whether there is substantial doubt about an organization's ability to continue as a going concern and to provide related footnote disclosures. This also provides guidance to a organization's management, with principles and definitions that are intended to reduce diversity in the timing and content of disclosures that are commonly provided by organizations today in the financial statement footnotes. This guidance is effective for annual periods beginning after December 15, 2016 and interim periods within annual periods beginning after December 15, 2016. Early adoption in permitted for annual and interim reporting periods for which the financial statements have not previously been issued. The Company does not expect this to impact its operating results, financial position, or cash flows.

3. Related Party Transactions

On September 17, 2007, the Company entered into a drilling program with Hoactzin Partners, L.P. ("Hoactzin") for ten wells consisting of approximately three wildcat wells and seven developmental wells to be drilled on the Company's Kansas Properties (the "Ten Well Program"). Peter E. Salas, the Chairman of the Board of Directors of the Company, is the controlling person of Hoactzin. He was also at the time the sole shareholder and controlling person of Dolphin Management, Inc., the general partner of Dolphin Offshore Partners, L.P., which was the Company's largest shareholder at that time.

Under the terms of the Ten Well Program, Hoactzin paid the Company $0.4 million for each well drilled in the Ten Well Program completed as a producing well and $0.25 million for each well that was non-productive. The terms of the Ten Well Program also provided that Hoactzin would receive all the working interest in the ten wells in the Program, but would pay an initial fee to the Company of 25% of its working interest revenues net of operating expenses. This is referred to as a management fee but, as defined, is in the nature of a net profits interest. The fee paid to the Company by Hoactzin would increase to 85% if net revenues received by Hoactzin reached an agreed payout point of approximately 1.35 times Hoactzin's purchase price (the "Payout Point") for its interest in the Ten Well Program.

In March 2008, the Company drilled and completed the final well in the Ten Well Program. Hoactzin paid a total of $3.85 million (the "Purchase Price") for its interest in the Ten Well Program resulting in the Payout Point being determined as $5.2 million.

On September 17, 2007, Hoactzin, simultaneously with subscribing to participate in the Ten Well Program, was conveyed a 75% net profits interest in the methane extraction project developed by MMC at the Carter Valley landfill owned by Republic Services in Church Hill, Tennessee (the "Methane Project"). Net profits, if any, from the Methane Project received by Hoactzin would have been applied towards the determination of the Payout Point for the Ten Well Program. However, through December 31, 2014, no payments were made to Hoactzin for its net profits interest in the Methane Project, because no net profits were generated.

The method of calculation of the net profits interest takes into account specific costs and expenses as well as gross gas revenues for the Methane Project. As a result of the startup costs and ongoing operating expenses, no net profits, as defined in the agreement, have been generated from startup in April, 2009 through December 31, 2014 for payment to Hoactzin under the net profits interest conveyed.

In February 2014, net revenues earned by Hoactzin from the Ten Well Program had exceeded $5.2 million and thereby reached the Payout Point which increased the management fee due to the Company by Hoactzin from 25% to 85% and reduced the net profits interest in the Methane Project from 75% to 7.5%.

On December 18, 2007, the Company entered into a Management Agreement with Hoactzin to manage on behalf of Hoactzin all of its working interest in certain oil and gas properties owned by Hoactzin and located in the onshore Texas Gulf Coast, offshore Texas, and offshore Louisiana (the “Management Agreement”).

As part of the consideration for the Company’s agreement to enter into the Management Agreement, Hoactzin granted to the Company an option to participate in up to a 15% working interest on a dollar for dollar cost basis in any new drilling or workover activities undertaken on Hoactzin’s managed properties during the term of the Management Agreement. The Management Agreement terminated by its own terms on December 18, 2012. The Company is assisting Hoactzin with becoming operator of record of these wells. The Company has entered into a transition agreement with Hoactzin whereby Hoactzin and its controlling member indemnify the Company for any costs or liabilities incurred by the Company resulting from such assistance, or the fact that the Company is the operator of record on certain of these wells.

During the course of the Management Agreement, the Company became the operator of certain properties owned by Hoactzin. The Company obtained from IndemCo, over time, bonds in the face amount of approximately $10.7 million for the purpose of covering plugging and abandonment obligations for Hoactzin’s operated properties located in federal offshore waters in favor of the BSEE, as well as certain private parties. In connection with the issuance of these bonds the Company signed a Payment and Indemnity Agreement with IndemCo whereby the Company guaranteed payment of any bonding liabilities incurred by IndemCo. Dolphin Direct Equity Partners, LP also signed the Payment and Indemnity Agreement, thereby becoming jointly and severally liable with the Company for the obligations to IndemCo. Dolphin Direct Equity Partners, L.P. is a private equity fund controlled by Peter E. Salas that has a significant economic interest in Hoactzin. Hoactzin had provided $6.6 million in cash to IndemCo as collateral for these potential obligations. As of May 15, 2014, all bonds issued by IndemCo and subject to the Payment and Indemnity Agreement have been released by the BSEE and have been cancelled by IndemCo. Accordingly, the exposure to the Company under any of the now cancelled IndemCo bonds or the indemnity agreement relating to those now cancelled bonds has decreased to zero.

As part of the transition process, Hoactzin secured new bonds from Argonaut Insurance Company to replace the IndemCo bonds. As noted above, all of the IndemCo bonds were replaced, and all IndemCo bonds were cancelled. Also as part of the transition to Hoactzin becoming operator of its own properties, right-of-use and easement ("RUE") bonds in the amount of $1.55 million were required by the regulatory process to be issued by Argonaut in the Company's name as current operator. Hoactzin is in the process of transferring these RUE bonds from the Company to Hoactzin. Hoactzin and Dolphin Direct signed an indemnity agreement with Argonaut as well as provided the required collateral for the new Argonaut bonds, including 100% cash collateral for the RUE bonds issued in the Company's name. The Company is not party to the indemnity agreement with Argonaut and has not provided any collateral for any of the Argonaut bonds issued. When the transfer of the RUE's and associated bonds is approved, the transfer of operations to Hoactzin would be complete and the Company's involvement in the Hoactzin properties will be ended.

As operator, the Company routinely contracted in its name for goods and services with vendors in connection with its operation of the Hoactzin properties. In practice, Hoactzin directly paid these invoices for goods and services that were contracted in the Company's name. During late 2009 and early 2010, Hoactzin undertook several significant operations, for which the Company contracted in the ordinary course. As a result of the operations performed in late 2009 and early 2010, Hoactzin had significant past due balances to several vendors, a portion of which were included on the Company's balance sheet. Payables related to these past due and ongoing operations remained outstanding at December 31, 2014 and 2013 in the amount of $159,000 and $327,000, respectively. The decrease in payables was due to payment by Hoactzin of invoices received by the Company from IndemCo related to bond premiums, which invoices have been paid by Hoactzin in full and the IndemCo bonds cancelled. The Company has recorded the Hoactzin-related payables and the corresponding receivable from Hoactzin as of December 31, 2014 and 2013 in its Consolidated Balance Sheets under "Accounts payable – other" and "Accounts receivable – related party". Since the second quarter of 2012, the only increase in the Hoactzin-related payables that have been recorded on the Company's Consolidated Balance Sheets relate to the IndemCo bond premiums. As all the IndemCo bonds have been cancelled, the outstanding balance of $159,000 should not increase in the future. However, Hoactzin has not made payments to reduce the $159,000 of past due balances from 2009 and 2010 since the second quarter of 2012. Based on these circumstances, the Company has elected to establish an allowance in the amount of $159,000 for the balances outstanding at December 31, 2014 and 2013. This allowance was recorded in the Company's Consolidated Balance Sheets under "Accounts receivable – related party". The resulting balances recorded in the Company's Consolidated Balance Sheets under "Accounts receivable – related party, less allowance for doubtful accounts of $159 and $257" are $0 and $168,000 at December 31, 2014 and 2013, respectively.

The Company has entered into an agreement with Hoactzin whereby Hoactzin and Dolphin Direct are indemnifying the Company for any costs or liabilities incurred by the Company resulting from such assistance, or the fact that the Company is still the operator of record on certain of these wells. Until such time as Hoactzin becomes operator of record on these wells and the corresponding bonding liability is transferred from the Company to Hoactzin, per the transition agreement, the Company is suspending drilling payments to Hoactzin. As of December 31, 2014 and 2013, the Company has suspended approximately $590,000 and $412,000 in payments, respectively. This balance of these suspended payments is recorded in the Consolidated Balance Sheet under "Accounts payable – related party".

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The Company has not advanced any funds to pay any obligations of Hoactzin. No borrowing capability of the Company has been used by the Company in connection with its obligations under the Management Agreement, except for those funds used to collateralize the appeal bond with RLI Insurance Company.

4. Oil and Gas Properties

The following table sets forth information concerning the Company's oil and gas properties: (in thousands):

| | December 31, | |
|---|---|---|
| | 2014 | 2013 |
| Oil and gas properties, at cost | $49,388 | $45,101 |
| Unevaluated properties, at cost | 462 | 736 |
| Accumulated depreciation, depletion and amortization | (24,437) | (21,714) |
| Oil and gas properties, net | $25,413 | $24,123 |

During the years ended December 31, 2014, 2013, and 2012, the Company recorded depletion expense of $2.8 million, $2.6 million and $3.0 million, respectively.

5. Manufactured Methane Facilities

The following table sets forth information concerning the Manufactured Methane facilities: (in thousands):

| | December 31, | |
|---|---|---|
| | 2014 | 2013 |
| Manufactured Methane facilities, at cost | $1,634 | $4,945 |
| Accumulated depreciation | - | (556 ) |
| Manufactured Methane facilities, net | $1,634 | $4,389 |

During each of the years ended December 31, 2014, 2013, and 2012, the Company recorded depreciation expense of $163,000, $136,000, and $101,000, respectively. In 2014, the Company recognized a non-cash impairment of the Manufactured Methane facilities in the amount of $2.8 million ($1.7 million net of tax effect). The impairment resulted from the Company's assessment that future cash flows, using historical costs and runtimes, were insufficient to recover the Manufactured Methane facilities' net book value. The Manufactured Methane facilities were written down to fair value amount calculated from estimated discounted cash flows, as well as certain expressions of interest with regards to the purchase by outside parties of the Company's Manufactured Methane facilities. (See Note 10. Fair Value Measurements)

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6. Other Property and Equipment

Other property and equipment consisted of the following as of December 31, 2014: (in thousands)

| Type | Depreciable Life | Gross Cost | Accumulated Depreciation | Net Book Value |
|---|---|---|---|---|
| Machinery and equipment | 5-7 yrs | $ 20 | $ 17 | $ 3 |
| Vehicles | 2-5 yrs | 430 | 233 | 197 |
| Other | 5 yrs | 63 | 63 | - |
| Total | | $ 513 | $ 313 | $ 200 |

Other property and equipment consisted of the following as of December 31, 2013: (in thousands)

| Type | Depreciable Life | Gross Cost | Accumulated Depreciation | Net Book Value |
|---|---|---|---|---|
| Machinery and equipment | 5-7 yrs | $ 20 | $ 13 | $ 7 |
| Vehicles | 2-5 yrs | 475 | 235 | 240 |
| Other | 5 yrs | 63 | 63 | - |
| Total | | $ 558 | $ 311 | $ 247 |

The Company uses the straight-line method of depreciation for other property and equipment. During each of the years ended December 31, 2014, 2013, and 2012, the Company recorded depreciation expense of $101,000, $170,000, and $258,000, respectively.

7. Discontinued Operations

Discontinued operations represent the income and expenses related to the Company's pipeline assets. The pipeline assets were sold in August 2013. The following table summarizes the amounts in net loss from discontinued operations, net of income tax presented in the consolidated statement of Operations for the years ended December 31, 2013 and 2012 (in thousands):

| | Years Ended December 31, 2013 | Years Ended December 31, 2012 |
|---|---|---|
| Revenues | $ 22 | $ 30 |
| Production costs and taxes | (164) | (315) |
| Depreciation, depletion, and amortization | - | (223) |
| Impairment | - | (5,242) |
| Gain on sale of assets | 128 | - |
| Deferred income tax benefit | (180) | 1,419 |
| Current income tax benefit | 57 | 20 |
| Net loss from discontinued operations, net of income tax | $ (137) | $ (4,311) |

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8. Long-Term Debt

Long-term debt consisted of the following: (in thousands)

| December 31, | 2014 | 2013 |
| --- | --- | --- |
| Revolving credit facility, with interest only payment until maturity. | $734 | $3,257 |
| Installment notes bearing interest at the rate of 5.5% to 8.25% per annum collateralized by vehicles with monthly payments including interest, insurance and maintenance of approximately $10 | 155 | 200 |
| Total long-term debt | 889 | 3,457 |
| Less current maturities | (65 ) | (82 ) |
| Long-term debt, less current maturities | $824 | $3,375 |

Future debt payments to unrelated entities as of December 31, 2014 consisted of the following: (in thousands)

| | 2015 | 2016 | 2017 | Total |
| --- | --- | --- | --- | --- |
| Bank Credit Facility | $ - | $ - | $734 | $734 |
| Company Vehicles | $ 65 | $ 56 | $34 | $155 |
| Total | $ 65 | $ 56 | $768 | $889 |

At December 31, 2014, the Company had a revolving credit facility with Prosperity Bank (formerly F&M Bank & Trust Company). Under the credit facility, loans and letters of credit are available to the Company on a revolving basis in an amount outstanding not to exceed the lesser of $40 million or the Company's borrowing base in effect from time to time. As of December 31, 2014, the Company's borrowing base was $14.3 million and the interest rate of prime plus 0.50% per annum. The Company's interest rate at December 31, 2014 was 3.75%, and matures on January 27, 2017. The borrowing base remains subject to the existing periodic redetermination provision in the credit facility. The credit facility is secured by substantially all of the Company's producing and non-producing oil and gas properties and the Company's Manufactured Methane facilities. The credit facility includes certain covenants with which the Company is required to comply. These covenants include leverage, interest coverage, and minimum liquidity ratios. The Company is in compliance with all of the credit facility covenants.

On March 16, 2015, the Company's senior credit facility with Prosperity Bank was amended to decrease the Company's borrowing base from $14.3 million to $7.8 million and extend the term of the facility to January 27, 2017. The borrowing base remains subject to the existing periodic redetermination provisions in the credit facility. The interest rate remained prime plus 0.50% per annum. The maximum line of credit of the Company under the Prosperity Bank credit facility remained $40 million.

The total borrowing by the Company under the Prosperity Bank facility at December 31, 2014 and December 31, 2013 was $734,000 and $3.3 million, respectively. The next borrowing base review will take place in July 2015.

9. Commitments and Contingencies

The Company is a party to lawsuits in the ordinary course of its business. The Company does not believe that it is probable that the outcome of any individual action will have a material adverse effect, or that it is likely that adverse outcomes of individually insignificant actions will be significant enough, in number or magnitude, to have in the aggregate a material adverse effect on its financial statements.

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On December 15, 2013, the Company entered into a 38 month lease (2 months free) for office space in Greenwood Village Colorado. The payment on this lease is approximately $2,700 per month and expired February 28, 2017. On May 14, 2014, the lease was amended to include additional leased space at the Greenwood Village Colorado office. The amendment extended the lease to expire on May 31, 2017. The monthly lease payments were amended as follows: $3,965.06 per month for the period June 2014 through May 2015; $4,090.94 per month for the period June 2015 through May 2016; $4,216.81 per month for the period June 2016 through May 2017. Future non-cancellable commitments related to this lease total approximately $48,000 due in 2015, $50,000 due in 2016, and $21,000 due in 2017.

Office rent expense for each of the three years ended December 31, 2014, 2013, and 2012 was $73,000, $92,000, and $80,000, respectively.

The Company as designated operator of the Hoactzin properties was administratively issued an "Incident of Non-Compliance" by BSEE during the quarter ended September 30, 2012 concerning one of Hoactzin's operated properties. This action calls for payment of a civil penalty of $386,000 for failure to provide, upon request, documentation to the BSEE evidencing that certain safety inspections and tests had been conducted in 2011. In the 4$^{th}$ quarter of 2012, the Company filed an administrative appeal with the Interior Board of Land Appeals ("IBLA") of this action in order to attempt to significantly reduce the civil penalty. This appeal required a fully collateralized appeal bond to postpone the payment obligation until the appeal was determined. The Company posted and collateralized this bond with RLI Insurance Company. If the bond was not posted, the appeal would have been administratively denied and the order to the Company as operator to pay the $386,000 penalty would have become final. On June 23, 2014, the IBLA affirmed the civil penalty without reduction. On September 22, 2014, the Company sought judicial review of the June 23, 2014 agency action in the federal district court in the Eastern District of Louisiana at New Orleans. While the civil penalty could ultimately be reduced in the judicial review process, as a result of the determination by the IBLA, the Company recorded a liability of $386,000 in the Company's Consolidated Balance Sheets under "Accrued and other current liabilities" and an expense in its Consolidated Statements of Operations under "Production costs and taxes" for the year ended December 31, 2014.

## 10. Fair Value Measurements

FASB ASC 820, "Fair Value Measurements and Disclosures", establishes a framework for measuring fair value. That framework provides a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets and liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). The three levels of the fair value hierarchy under FASB ASC 820 are described as follows:

Level 1 – Observable inputs, such as unadjusted quoted prices in active markets, for substantially identical assets and liabilities.

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Level 2 – Observable inputs other than quoted prices within Level 1 for similar assets and liabilities. These include quoted prices for similar assets and liabilities in active markets, quoted prices for identical assets and liabilities in markets that are not active, or other inputs that are observable or can be corroborated by observable market data. If the asset or liability has a specified or contractual term, the input must be observable for substantially the full term of the asset or liability.

Level 3 – Unobservable inputs that are supported by little or no market activity, generally requiring a significant amount of judgment by management. The assets or liabilities fair value measurement level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. Valuation techniques used need to maximize the use of observable inputs and minimize the use of unobservable inputs.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. Further, although the Company believes its valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date.

Upon completion of wells, the Company records an asset retirement obligation at fair value using Level 3 assumptions.

Nonfinancial assets and liabilities are measured at fair value on a nonrecurring basis upon impairment. The following table sets forth by level, within the fair value hierarchy, the Company's assets and liabilities at fair value on a recurring basis as of December 31, 2014 (in thousands):

| | Level 1 | Level 2 | Level 3 |
|---|---|---|---|
| Maufacured Methane facilities | $ - | $ - | $1,634 |

The following table sets forth the reconciliation of the change in value of the Company's Manufactured Methane facilities from December 31, 2013 to December 31, 2014 (in thousands):

| | |
|---|---|
| Balance December 31, 2013 | $4,389 |
| Additions | 204 |
| Depreciation Expense | (163 ) |
| Balance at December 31, 2014 prior to impairment | 4,430 |
| Pre-tax non-cash impairment | (2,796) |
| Balance December 31, 2014 | $1,634 |

Fair value of the Manufactured Methane facilities at December 31, 2014 was based on estimated discounted future net cash flows, as well as certain expressions of interest with regards to the purchase by outside parties of the Company's Manufactured Methane facilities.

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The carrying amounts of other financial instruments including cash and cash equivalents, accounts receivable, account payables, accrued liabilities and long term debt in our balance sheet approximates fair value as of December 31, 2014 and December 31, 2013.

11. Asset Retirement Obligation

Our asset retirement obligations represent the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties at the end of their productive lives in accordance with applicable laws. The following table summarizes the Company's Asset Retirement Obligation transactions for the years ended December 31, 2013 and 2014 (in thousands):

| | |
|---|---|
| Balance December 31, 2012 | $2,099 |
| Accretion expense | 120 |
| Liabilities incurred | 26 |
| Liabilities settled | (417 ) |
| Revision in estimated liabilities | (48 ) |
| Balance December 31, 2013 | $1,780 |
| Accretion expense | 114 |
| Liabilities incurred | 46 |
| Liabilities settled | (70 ) |
| Revisions in estimated liabilities | 138 |
| Balance December 31, 2014 | $2,008 |

The liabilities settled during 2013 also include removal of $348,000 from the Asset Retirement Obligation related to the sale of the Tennessee oil and gas properties. The revisions in estimated liabilities in 2014 and 2013 resulted primarily from change in timing of wells to be plugged.

12. Stock Options

In October 2000, the Company approved a Stock Incentive Plan which was effective for a ten-year period commencing on October 25, 2000 and ending on October 24, 2010. The aggregate number of shares of Common Stock as to which options and Stock Appreciation Rights may be granted to participants under the original Plan was not to exceed 7,000,000. The most recent amendment to the Plan increasing the number of shares that may be issued under the Plan by 3,500,000 shares and extending the Plan for another ten years was approved by the Company's Board of Directors on February 1, 2008 and approved by the Company's shareholders at the Annual Meeting of Stockholders held on June 2, 2008. Options are not transferable, are exercisable for 3 months after voluntary resignation from the Company, and terminate immediately upon involuntary termination from the Company. The purchase price of shares subject to this Plan shall be determined at the time the options are granted, but are not permitted to be less than 85% of the fair market value of such shares on the date of grant. Furthermore, a participant in the Plan may not, immediately prior to the grant of an Incentive Stock Option, own stock in the Company representing more than ten percent of the total voting power of all classes of stock of the Company unless the per share option price specified by the Board for the Incentive Stock Options granted such a participant is at least 110% of the fair market value of the Company's stock on the date of grant and such option, by its terms, is not exercisable after the expiration of 5 years from the date such stock option is granted.

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Stock option activity in 2014, 2013, and 2012 is summarized below:

| | 2014 | | 2013 | | 2012 | |
|---|---|---|---|---|---|---|
| | Shares | Weighted Average Exercise Price | Shares | Weighted Average Exercise Price | Shares | Weighted Average Exercise Price |
| Outstanding, beginning of year | 870,250 | $ 0.59 | 1,372,250 | $ 0.61 | 1,471,000 | $ 0.61 |
| Granted | 100,000 | $ 0.44 | 75,000 | $ 0.54 | 87,500 | $ 0.85 |
| Exercised | - | $ - | - | $ - | (105,000 ) | $ 0.50 |
| Expired/cancelled | (70,000 ) | $ 0.63 | (577,000 ) | $ 0.72 | (81,250 ) | $ 1.12 |
| Outstanding, end of year | 900,250 | $ 0.57 | 870,250 | $ 0.59 | 1,372,250 | $ 0.61 |
| Exercisable, end of year | 900,250 | $ 0.57 | 790,250 | $ 0.60 | 1,212,250 | $ 0.62 |

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

| Weighted Average Exercise Price | Options Outstanding (shares) | Weighted Average Remaining Contractual Life (years) | Options Exercisable (shares) |
|---|---|---|---|
| $0.50 | 400,000 | 0.8 | 400,000 |
| $0.43 | 50,000 | 0.1 | 50,000 |
| $0.44 | 94,000 | 0.7 | 94,000 |
| $1.08 | 50,000 | 1.3 | 50,000 |
| $1.16 | 18,750 | 1.3 | 18,750 |
| $0.84 | 18,750 | 1.5 | 18,750 |
| $0.72 | 18,750 | 1.8 | 18,750 |
| $0.75 | 18,750 | 2.0 | 18,750 |
| $1.07 | 18,750 | 2.3 | 18,750 |
| $0.81 | 18,750 | 2.5 | 18,750 |
| $0.73 | 18,750 | 2.8 | 18,750 |
| $0.64 | 18,750 | 3.0 | 18,750 |
| $0.62 | 18,750 | 3.2 | 18,750 |
| $0.48 | 18,750 | 3.5 | 18,750 |
| $0.41 | 18,750 | 3.8 | 18,750 |
| $0.41 | 25,000 | 4.0 | 25,000 |
| $0.48 | 25,000 | 4.2 | 25,000 |
| $0.44 | 25,000 | 4.5 | 25,000 |
| $0.44 | 25,000 | 4.8 | 25,000 |
| | 900,250 | | 900,250 |

During 2014, the Company issued the following options to each of the non-executive directors that remain outstanding as of December 31, 2014. These options vested upon grant date.

| Options Issued to Each Non-executive Director | Total Options Issued to Non-executive Directors | Exercise Price | Grant Date | Expiration Date |
|---|---|---|---|---|
| 6,250 | 25,000 | $ 0.41 | 1/3/2014 | 1/2/2019 |
| 6,250 | 25,000 | $ 0.48 | 4/1/2014 | 3/31/2019 |
| 6,250 | 25,000 | $ 0.44 | 7/2/2014 | 7/1/2019 |
| 6,250 | 25,000 | $ 0.44 | 10/2/2014 | 10/1/2019 |

The weighted average fair value per share of options granted in 2014 was $0.22 and 2013 was $0.25 calculated using the Black Scholes option pricing model.

Compensation expense related to stock options was $32,000 in 2014 and was $(28,000) in 2013 and $52,000 in 2012. The 2013 amount was comprised of $32,000 of current year compensation expense offset by reversal of $59,500 previously recognized as compensation expense. This expense is recorded in “General and administrative” in the Consolidated Statements of Operations. The fair value of stock options used to compute share based compensation is the estimated present value at grant date using the Black Scholes option pricing model with weighted average assumptions for 2014 of expected volatility of 53.3%, a risk free interest rate of 3.27% and an expected option life remaining from 0.1 to 4.8 years. The weighted average assumptions for 2013 were expected volatility of 47.6%, a risk free interest rate of 2.97% and an expected option life remaining from 0.1 to 4.8 years. The weighted average assumptions used for 2012 were expected volatility of 65.0%, a risk fee interest rate of 2.71% and an expected option life remaining for 0.1 years to 4.8 years.

On January 5, 2015, options to purchase 25,000 common shares at $0.25 per share were issued to the Company’s non-executive directors. These options fully vested upon grant date and will expire on January 4, 2020.

13. Income Taxes

The Company had taxable income for the years ended December 31, 2014, 2013 and 2012.

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A reconciliation of the statutory U.S. Federal income tax and the income tax provision included in the accompanying consolidated statements of operations is as follows (in thousands):

| Year Ended December 31, 2014 | Total |
|---|---|
| Statutory rate | 34 % |
| Tax (benefit) expense at statutory rate | $(270) |
| State income tax (benefit) expense | (40 ) |
| Permanent difference | 304 |
| | |
| Total income tax provision (benefit) | $(6 ) |

| Year Ended December 31, 2013 | Continuing Operations | Discontinued Operations | Total |
|---|---|---|---|
| Statutory rate | 34 % | 34 % | 34 % |
| Tax (benefit) expense at statutory rate | $ 1,689 | $ (5 ) | $1,684 |
| State income tax (benefit) expense | 255 | - | 255 |
| Permanent difference | 4 | - | 4 |
| Other | 62 | (62 ) | - |
| Net change in deferred tax asset valuation allowance | - | 190 | 190 |
| | | | |
| Total income tax provision (benefit) | $ 2,010 | $ 123 | $2,133 |

| Year Ended December 31, 2012 | Continuing Operations | Discontinued Operations | Total |
|---|---|---|---|
| Statutory rate | 34 % | 34 % | 34 % |
| Tax (benefit) expense at statutory rate | $ 2,229 | $ (1,955 ) | $274 |
| State income tax (benefit) expense | 43 | - | 43 |
| Permanent difference | 35 | (84 ) | (49 ) |
| Other | 6 | - | 6 |
| Net change in deferred tax asset valuation allowance | - | 600 | 600 |
| | | | |
| Total income tax provision (benefit) | $ 2,313 | $ (1,439 ) | $874 |

Management has evaluated the positions taken in connection with the tax provisions and tax compliance for the years included in these financial statements. The Company believes that all of the positions it has taken will prevail on a more likely than not basis. As such no disclosure of such positions was deemed necessary. Management continuously estimates its ability to recognize a deferred tax asset related to prior period net operating loss carry forwards based on its anticipation of the likely timing and adequacy of future net income.

In 2013, management determined using the “more likely than not” criteria for recognition that upon sale of the Pipeline asset, the Company would not be able to utilize the state net operating loss carryforwards associated with TPC and the Tennessee oil and gas properties, and therefore established an allowance for these state net operating loss carryforwards. The total valuation allowance at December 31, 2014 and 2013 was $790,000.

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As of December 31, 2014, the Company had net operating loss carry forwards of approximately $20.2 million which will expire between 2018 and 2031 if not utilized. The Company recognizes the excess income tax benefit associated with certain stock compensation deductions when such deductions produce a reduction in the Company's current tax liability under the "with" and "without" approach. Due to cumulative net operating loss carryforwards ("NOLs") that exceeded the excess income tax benefits generated in prior reporting periods, the Company has not recognized the excess benefit of the tax deductions upon the exercise of stock options in any prior reporting period. As of December 31, 2014, the Company's estimated net operating losses for tax return filing purposes exceeds the gross amount for financial reporting purposes by $1.9M. The tax effect of this excess tax benefit will be recorded as a reduction to APIC in a future reporting period when the cash benefit is realized. Our open tax years include all returns filed for 2011 and later. In addition, any of the Company's NOLs for tax reporting purposes are still subject to review and adjustment by both the Company and the IRS to the extent such NOLs should be carried forward into an open tax year.

The Company's deferred tax assets and liabilities are as follows: (in thousands)

| | Year Ended December 31, | |
|---|---|---|
| | 2014 | 2013 |
| Net deferred tax assets - current: | | |
| Charitable contribution | $- | $62 |
| Bad debt | $68 | $68 |
| Total deferred tax assets – current | $68 | $130 |
| | | |
| Net deferred tax assets (liabilities) – noncurrent: | | |
| Net operating loss carryforwards | $7,173 | $7,723 |
| Oil and gas properties | (894) | 979 |
| Property, Plant and Equipment | 711 | (1,562) |
| Asset retirement obligation | 786 | 565 |
| Tax credits | 202 | 196 |
| Miscellaneous | 95 | 98 |
| Valuation allowance | (790) | (790) |
| Total deferred tax assets – noncurrent | $7,283 | $7,209 |
| | | |
| Net deferred tax asset | $7,351 | $7,339 |

14. Quarterly Data and Share Information (unaudited)

The following tables sets forth for the fiscal periods indicated, selected consolidated financial data
(In thousands, except per share data)

| Fiscal Year Ended 2014 | 1st Qtr | 2nd Qtr | 3rd Qtr | 4th Qtr |
|---|---|---|---|---|
| Revenues | $3,505 | $3,985 | $3,619 | $2,679 |
| Net income from continuing operations | 424 | 377 | 425 | (2,014) |
| Income per common share from continuing operations | $0.01 | $0.01 | $0.01 | $(0.03) |

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| Fiscal Year Ended 2013 | 1st Qtr | 2nd Qtr | 3rd Qtr | 4th Qtr |
|---|---|---|---|---|
| Revenues | $4,314 | $3,871 | $4,034 | $3,481 |
| Net income from continuing operations | 978 | 805 | 535 | 638 |
| Net (loss) from discontinued operations | (41 ) | (33 ) | (54 ) | (9 ) |
| Income per common share from continuing operations | $0.02 | $0.01 | $0.01 | $0.01 |
| (Loss) per common share from discontinued operations | $(0.00 ) | $(0.00 ) | $(0.00 ) | $(0.00 ) |

15. Supplemental Oil and Gas Information (unaudited)

Information with respect to the Company’s oil and gas producing activities is presented in the following tables. Estimates of reserves quantities, as well as future production and discounted cash flows before income taxes, were determined by LaRoche Petroleum Consultants Ltd. All of the Company’s reserves were located in the United States.

Capitalized Costs Related to Oil and Gas Producing Activities

The table below reflects our capitalized costs related to our oil and gas producing activities at December 31, 2014 and 2013 (in thousands):

| | Years Ended December 31, | |
|---|---|---|
| | 2014 | 2013 |
| Proved oil and gas properties | $49,388 | $45,101 |
| Unproved properties | 462 | 736 |
| Total proved and unproved oil and gas properties | $49,850 | $45,837 |
| | | |
| Less accumulated depreciation, depletion and amortization | (24,437) | (21,714) |
| Net oil and gas properties | $25,413 | $24,123 |

Oil and Gas Related Costs

The following table sets forth information concerning costs incurred, including accruals, related to the Company’s oil and gas property acquisition, exploration and development activities (in thousands):

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Property acquisitions proved | $- | $- | $- |
| Property acquisitions unproved | 598 | 488 | 188 |
| Exploration cost | 2,367 | 914 | 4,608 |
| Development cost | 864 | 998 | 2,649 |
| Total | $3,829 | $2,400 | $7,445 |

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Results of Operations from Oil and Gas Producing Activities

The following table sets forth the Company's results of operations from oil and gas producing activities (in thousands):

| | Years Ended December 31, 2014 | 2013 | 2012 |
|---|---|---|---|
| Revenues | $13,260 | $15,325 | $19,885 |
| Production costs and taxes | (4,876 ) | (4,854 ) | (5,610 ) |
| Depreciation, depletion and amortization | (2,766 ) | (2,606 ) | (3,044 ) |
| Income from oil and gas producing activities | $5,618 | $7,865 | $11,231 |

In the presentation above, no deduction has been made for indirect costs such as general corporate overhead or interest expense.  No income taxes are reflected above due to the Company's operating tax loss carry-forward position.

Estimated Quantities of Oil and Gas Reserves

The following table sets forth the Company's net proved oil and gas reserves and the changes in net proved oil and gas reserves for the years ended December 31, 2012, 2013 and 2014.  All of the Company's proved reserves are located in the United States of America.

| | Oil (MBbl) | Gas (MMcf) | MBOE |
|---|---|---|---|
| Proved reserves at December 31, 2011 | 2,591 | 4 | 2,592 |
| Revisions of previous estimates | (337 ) | 61 | (327 ) |
| Improved recovery | - | - | - |
| Purchase of reserves in place | - | - | - |
| Extensions and discoveries | 186 | - | 186 |
| Production | (227 ) | (43 ) | (234 ) |
| Sales of reserves in place | - | - | - |
| Proved reserves at December 31, 2012 | 2,213 | 22 | 2,217 |
| Revisions of previous estimates | (153 ) | 16 | (151 ) |
| Improved recovery | - | - | - |
| Purchase of reserves in place | - | - | - |
| Extensions and discoveries | 170 | - | 170 |
| Production | (166 ) | (38 ) | (172 ) |
| Sales of reserves in place | (24 ) | - | (24 ) |
| Proved reserves at December 31, 2013 | 2,040 | - | 2,040 |
| Revisions of previous estimates | (253 ) | - | (253 ) |
| Improved recovery | - | - | - |
| Purchase of reserves in place | - | - | - |
| Extensions and discoveries | 164 | - | 164 |

| | | | |
|---|---|---|---|
| Production | (154 ) | - | (154 ) |
| Sales of reserves in place | - | - | - |
| | | | |
| Proved reserves at December 31, 2014 | 1,797 | - | 1,797 |
| | | | |
| Proved developed reserves at: | | | |
| December 31, 2011 | 1,939 | 4 | 1,940 |
| December 31, 2012 | 1,822 | 22 | 1,826 |
| December 31, 2013 | 1,575 | - | 1,575 |
| December 31, 2014 | 1,438 | - | 1,438 |
| | | | |
| Proved undeveloped reserves at: | | | |
| December 31, 2011 | 652 | - | 652 |
| December 31, 2012 | 391 | - | 391 |
| December 31, 2013 | 465 | - | 465 |
| December 31, 2014 | 359 | - | 359 |

The Company's Proved Undeveloped Reserves at December 31, 2014 included 27 locations as compared to 29 locations at December 31, 2013. During 2014, one of the PUDs contributing reserves of 12 MBbl that existed at December 31, 2013 was drilled and moved into proved developed reserves, 9 PUDs contributing reserves of 155 MBbl were dropped from the PUD reserves at December 31, 2014, and there was a 50 MBbl downward revision in PUD reserves. These reductions were partially offset by the addition of 8 PUD locations which contributed 111 MBbl of reserves at December 31, 2014. The future development cost related to the Company's Proved Undeveloped locations at December 31, 2014 was approximately $8.7 million. The Company intends to fund the drilling of these locations through operating cash flow and, as needed, supplement the funding by drawing on the Company's credit facility.

The following table identifies the reserve value by category and the respective present values, before income taxes, discounted at 10% as a percentage of total proved reserves (in thousands):

| | Year Ended 12/31/14 | | | Year Ended 12/31/13 | | | Year Ended 12/31/12 | | |
|---|---|---|---|---|---|---|---|---|---|
| | Oil | Gas | Total | Oil | Gas | Total | Oil | Gas | Total |
| Total proved reserves year-end reserve report | $40,417 | - | $40,417 | $47,856 | - | $47,856 | $53,906 | $ 5 | $53,911 |
| Proved developed producing reserves (PDP) | $32,059 | - | $32,059 | $34,440 | - | $34,440 | $42,621 | $ 5 | $42,626 |
| % of PDP reserves to total proved reserves | 79 % | - | 79 % | 72 % | - | 72 % | 79 % | - | 79 % |
| Proved developed non-producing reserves | $2,956 | - | $2,956 | $4,868 | - | $4,868 | $3,234 | - | $3,234 |
| % of PDNP reserves to total proved reserves | 7 % | - | 7 % | 10 % | - | 10 % | 6 % | - | 6 % |
| Proved undeveloped reserves (PUD) | $5,402 | - | $5,402 | $8,548 | - | $8,548 | $8,051 | - | $8,051 |
| % of PUD reserves to total proved reserves | 14 % | - | 14 % | 18 % | - | 18 % | 15 % | - | 15 % |

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Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows from the Company's proved oil and gas reserves is presented in the following table (in thousands):

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Future cash inflows | $158,792 | $183,801 | $194,941 |
| Future production costs and taxes | (71,951 ) | (82,307 ) | (82,069 ) |
| Future development costs | (10,014 ) | (11,162 ) | (7,894 ) |
| Future income tax expenses | (13,092 ) | (18,910 ) | (19,472 ) |
| Future net cash flows | 63,735 | 71,422 | 85,506 |
| | | | |
| Discount at 10% for timing of cash flows | (29,204 ) | (32,714 ) | (40,152 ) |
| Standardized measure of discounted future net cash flows | $34,531 | $38,708 | $45,354 |

The following are the principal sources of change in the standardized measure of discounted future net cash flows from the Company's proved oil and gas reserves (in thousands):

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Balance, beginning of year | $38,708 | $45,354 | $51,909 |
| Sales, net of production costs and taxes | (8,385 ) | (10,471 ) | (14,275 ) |
| Discoveries and extensions, net of costs | 4,231 | 4,047 | 6,967 |
| Purchase of reserves in place | - | - | - |
| Sale of reserves in place | - | (767 ) | - |
| Net changes in prices and production costs | (829 ) | (1,277 ) | (6,067 ) |
| Revisions of quantity estimates | (6,610 ) | (4,306 ) | (9,883 ) |
| Previously estimated development cost incurred during the year | 508 | 3,149 | 8,760 |
| Changes in future development costs | (1,913 ) | (1,392 ) | (1,919 ) |
| Changes in production rates (timing) and other | 1,312 | 368 | (5,657 ) |
| Accretion of discount | 4,247 | 4,593 | 6,223 |
| Net change in income taxes | 3,262 | (590 ) | 9,296 |
| Balance, end of year | $34,531 | $38,708 | $45,354 |

Estimated future net cash flows represent an estimate of future net revenues from the production of proved reserves using average sales prices, along with estimates of the operating costs, production taxes and future development and abandonment cost (less salvage value) necessary to produce such reserves. Future income taxes were calculated by applying the statutory federal and state income tax rates to pre-tax future net cash flows, net of the tax basis of the properties and utilizing available tax loss carryforwards related to oil and gas operations. The oil prices used for December 31, 2014, 2013, and 2012, were $88.34, $90.11, $88.08 per barrel of oil respectively. The gas price used in 2012 was $2.76. The Company's proved reserves as of December 31, 2014, 2013 and 2012 were measured by using commodity prices based on the twelve month unweighted arithmetic average of the first day of the month price for the period January through December. No deduction has been made for depreciation, depletion or any indirect costs such as general corporate overhead or interest expense.

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