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, 2018** 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 (state or other jurisdiction of Incorporation or organization)	**87-0267438** (I.R.S. Employer Identification No.)
8000 E. Maplewood Ave., Suite 130, Greenwood Village, CO (Address of Principal Executive Offices)	80111 (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, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer ☐	Accelerated Filer ☐
Non-accelerated Filer ☐ (Do not check if a Smaller Reporting Company)	Smaller Reporting Company ☒
	Emerging growth company ☐
	If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act ☐

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 $3.9 million (June 29, 2018 closing price $0.75).

The number of shares outstanding of the registrant's $.001 par value common stock as of the close of business on March 25, 2019 was 10,644,252.

Table of Contents

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 2018 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.

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.

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. A polymer gel treatment of a well that produces from a water-drive reservoir is intended to reduce excessive water production and increase oil or gas production. Candidate 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 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.

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 or 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 rates 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.

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 from 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 that purpose. On June 11, 2011, the stockholders of the Company approved an Agreement and Plan of Merger 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 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 exploration and production is in Kansas.

The Company’s wholly-owned subsidiary, Tengasco Pipeline Corporation (“TPC”) owned and operated a 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 assets on August 16, 2013.

The Company’s wholly-owned subsidiary, Manufactured Methane Corporation (“MMC”) operated a treatment and delivery facilities in Church Hill, Tennessee for the extraction of methane gas from a landfill for eventual sale as natural gas or for the generation of electricity. The Company sold all its methane facility assets, except the applicable U.S. patent, on January 26, 2018.

General

1. The Kansas Properties

The Company’s operated properties in Kansas are located in central Kansas and as of December 31, 2018 included 174 producing oil wells, 20 shut-in wells, and 38 active disposal wells (the “Kansas Properties”). 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 approximately 0.5% to 15%. The Company maintains a 100% working interest in most of its wells in Kansas.

During 2018, the Company participated in drilling two operated wells, one of which was completed as a producing well, and three non-operated wells, none of which 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 leases, the Company has historically added proven direct offset locations.

A. Kansas Production

The Company's gross operated oil production in Kansas decreased by 1.5 MBbl from 121.7 MBbl in 2017 to 120.2 MBbl in 2018. This decrease was primarily the result of natural declines during 2018, partially offset by polymer work performed in the second and third quarters of 2018 and completion of a drilling well in October 2018. The capital projects undertaken by the Company in 2018 were primarily funded by cash flow.

B. Kansas Ten Well Drilling Program

On September 17, 2007, the Company entered into a ten well drilling program with Hoactzin Partners, L.P. ("Hoactzin"), consisting of wells to be drilled on the Company's Kansas Properties (the "Program"). 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. 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 as a management fee. The fee paid to the Company increased from 25% to 85% in February 2014.

In 2018, the wells from the Program produced total gross production of 6.8 MBbl of which the revenues from 5.8 MBbl were net to the Company. During the 4th quarter of 2018, the Company acquired Hoactzin's interest in the Program wells for $131,290.

2. Tennessee Properties

A. Oil, Gas, and Pipeline Assets

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. On August 16, 2013, the Company closed a sale to Swan Creek Partners LLC of all of the Company's oil and gas leases and producing assets in Tennessee as well as all the Company's pipeline assets for $1.5 million.

B. 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. The Company installed a proprietary combination of advanced gas treatment technology to extract the methane component of the purchased gas stream. (the "Methane Project").

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.

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 was sold under a twenty year firm price contract with Holston Electric Cooperative, Inc., the local distributor, and Tennessee Valley Authority ("TVA") 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 paid 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) or approximately $.129 per KWH. Beginning in January 2022 the price paid for electricity will no longer include the three-cent "green" premium component. A one-eighth royalty on electricity revenues has been paid to the landfill owner.

On September 17, 2007, Hoactzin was conveyed a 75% net profits interest in the Methane Project. Since the start of 2014, there have been no methane gas sales or revenues and consequently no net profits attributable to Hoactzin's net profits interest.

On January 26, 2018, the Company closed a sale to Tennessee Renewable Group LLC for all of the Company's Manufactured Methane assets, except for the applicable U.S. patent, for $2.65 million. Hoactzin expressly released all claims in future periods against both the Company and Tennessee Renewable Group LLC based on the September 17, 2007 net profits agreement described immediately above.

3. 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 as well as acquisition and drilling opportunities in other 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") in Kansas City, Kansas and to CHS McPherson Refinery ("CHS") in McPherson, Kansas. Both Coffeyville and CHS 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 oil prices offered by the refineries fluctuate from time to time.

Electricity generated at the Company's MMC site in Tennessee was sold to Holston Electric Cooperative and TVA.

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.

Distribution Methods of Products or Services

Crude oil is normally delivered to refineries in Kansas by tank truck. Electricity generated at the Company's Methane Facility was 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 or other states 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. 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 and CHS, 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 oil prices offered by the refineries fluctuate from time to time.

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.

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.

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 effect these present and future laws, rules, and regulations will have on the Company’s current and future operations.

Research and Development

None.

Number of Total Employees and Number of Full-Time Employees

At December 31, 2018, the Company had 12 full time employees and no part-time employees. These employees are located in Colorado, Kansas, and Texas. At January 26, 2018, the Company reduced its number of full time employees from 14 to 13 and no longer has any employees in Tennessee. This employee reduction was a result of the Company selling its Manufactured Methane assets located at the Carter Valley landfill in Tennessee. During 2018, the company reduced its Kansas employees by one, resulting in the 12 full time employees at December 31, 2018.

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.

As of December 31, 2018, the Company had no outstanding principal amount of indebtedness under its credit facility with Prosperity Bank. Although the Company had no bank indebtedness, should it experience 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 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 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 condition.

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, these adverse conditions could lead to non-compliance with certain credit facility covenants, ultimately causing the Company to default under its revolving credit facility.

The Company’s Credit Facility is Subject to Variable Rates of Interest and Contains Certain Financial Covenants 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.

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 in Tennessee and the Company's related pipeline assets. In addition, the Company has recorded an impairment of its oil and gas properties during 2008, 2015, and 2016, impairments of its pipeline assets during 2010 and 2012, and an impairment of its methane facility in 2014. As of December 31, 2018, the Company has an accumulated deficit of $51.5 million. The Company recorded net losses of $2.0 million in 2009, $1.7 million in 2010, $0.1 million in 2012, $0.8 million in 2014, $24.7 million in 2015, $4.2 million in 2016, and $0.6 million in 2017. 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.

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 may have a negative 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.

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.

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 experienced ceiling test failures resulting in recording non-cash impairments of $14.5 million. During 2016, the Company recorded ceiling test failures resulting in recording non-cash impairment of $2.7 million. Should prices continue at depressed levels during future periods, the Company may be required to record additional impairment of its oil properties.

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

At December 31, 2018, 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. At December 31, 2018, federal net operating loss carryforwards amounted to approximately $35.6 million, of which $34.6 million expires between 2019 and 2037 which can offset 100% of taxable income and $1 million that has an indefinite carryforward period which can offset 80% of taxable income per year. The total net deferred tax asset was $130,000 at December 31, 2018 and $242,000 at 2017. In 2018, the Company released a portion of the allowance related to its MTC as a result of the 2017 Tax Act. The Company recorded an allowance on the remaining deferred tax asset at December 31, 2018 primarily due to cumulative losses incurred during the 3 years ended December 31, 2018. The Company recorded a full allowance against the deferred tax asset net of the AMT credit at December 31, 2017 primarily due to cumulative losses incurred during the 3 years ended December 31, 2017. The total valuation allowance December 31, 2018 was $11.5 million, and $12.1 million at December 31, 2017.

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.

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 and 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 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.

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 any future project involving the extraction of methane gas from non-conventional reserves such as landfill gas streams, would require 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.

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, or 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.

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. 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 American, 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 25, 2019, Mr. Salas individually and through Dolphin controls 5,294,241 shares of the Company's common stock and had options granting him the right to acquire an additional 5,000 shares of common stock. His ownership and voting control of approximately 49.8% 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.

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

At March 25, 2019, the Company had 10,644,252 shares of common stock outstanding of which 5,459,621 shares were held by officers, directors, and affiliates. In addition, options to purchase 15,000 shares of unissued common stock were granted under the Tengasco, Inc. Stock Incentive Plan all of which were vested at March 25, 2019.

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 Would 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 10.6 million shares have been issued. The potential issuance of the approximately 89.4 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 American, 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 1,978 square feet located at 8000 E. Maplewood Ave., Suite 130, Greenwood Village, Colorado at a current rental of $4,038 per month, expiring in August 2020. The Company also leases an office in Hays, Kansas at a rental of $750 per month that is currently a month to month lease and a storage yard in Hays, Kansas at a rental of $350 per month that is also a month to month lease.

The Company carries commercial insurance as well as property insurance on its offices, vehicles, and office contents. The Company also carried property insurance on its methane facility which has been discontinued as a result of the sale of this facility in January 2018. As of December 31, 2018, 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, 2018 contained 15,302 gross acres (11,742 net acres) in central Kansas. Of these acres, 13,870 gross acres (11,447 net acres) were 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 15%. 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 2018, the Company participated in drilling two operated wells, one of which was completed as a producing well, and three non-operated wells, none of which 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.

Reserve and Production Summary

The following tables indicate the county breakdown of 2018 production and reserve values as of December 31, 2018.

Production by County

Area	Gross Production MBOE	Average Net Revenue Interest	Percentage of Total Oil Production
Rooks County, KS	80.4	0.820700	66.9%
Trego County, KS	15.5	0.804067	12.9%
Ellis County, KS	6.3	0.801706	5.2%
Barton County, KS	5.5	0.815019	4.6%
Graham County, KS	3.7	0.861997	3.1%
Russell County, KS	3.0	0.856987	2.5%
Rush County, KS	2.2	0.859672	1.8%
Osborne County, KS	1.4	0.588648	1.2%
Pawnee County, KS	1.3	0.797860	1.1%
Stafford County, KS	0.9	0.716073	0.7%
Total	**120.2**		**100.0%**

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

Area	Proved Developed	Proved Undeveloped	Proved Reserves	% of Total
Rooks County, KS	$ 9,359	$ 118	$ 9,477	67.8%
Trego County, KS	1,702	363	2,065	14.8%
Barton County, KS	805	—	805	5.7%
Graham County, KS	506	222	728	5.2%
Ellis County, KS	406	—	406	2.9%
Rush County, KS	235	—	235	1.7%
Russell County, KS	135	—	135	1.0%
Pawnee County, KS	70	—	70	0.5%
Osborne County, KS	40	—	40	0.3%
Stafford County, KS	15	—	15	0.1%
Ness County, KS	—	—	—	—%
Logan County, KS	—	—	—	—%
Total	**$ 13,273**	**$ 703**	**$ 13,976**	**100.0%**

Reserve Analyses

The Company's estimated total net proved reserves of oil and natural gas as of December 31, 2018 and 2017, 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.

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 Geologist has 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.

Total Proved Reserves as of December 31, 2018

	Producing	Non Producing	Undeveloped	Total
Oil (MBbl)	948	28	118	1,094
Future net cash flows before income taxes discounted at 10% *(in thousands)*	$ 12,534	$ 739	$ 703	$ 13,976

Total Proved Reserves as of December 31, 2017

	Producing	Non-producing	Undeveloped	Total
Oil (MBbl)	774	58	38	870
Future net cash flows before income taxes discounted at 10% *(in thousands)*	$ 7,065	$ 1,082	$ 23	$ 8,170

Historically, all drilling has primarily been funded by cash flows from operations with supplemental funding provided by the Company's credit facility.

The oil price after basis adjustments used in our December 31, 2018 reserve valuation was $60.21 per Bbl compared to $45.83 per Bbl used in our December 31, 2017 reserve valuation. The primary factor causing the increase in proved producing and undeveloped reserve volumes from December 31, 2017 levels was related to increased oil prices.

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, 2018. 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.

Production

The following tables summarize for the past three fiscal years the volumes of oil produced from operated properties, the Company's operating costs, and the Company's average sales prices for its oil. The net production volumes excluded volumes produced to royalty interest or other parties' working interest.

Kansas							
	Gross Production		Net Production		Cost of Net Production	Average Sales Price	
Years Ended December 31,	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	(Per BOE)	Oil (Bbl)	Gas (Per Mcf)
2018	120	—	98	—	$ 32.52	$ 59.48	—
2017	122	—	99	—	$ 29.77	$ 45.43	—

Oil and Gas Drilling Activities

During 2018, the Company participated in drilling two operated wells, one of which was completed as a producing well, and three non-operated wells, none of which 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.

Gross and Net Wells

The following tables set forth the fiscal years ending December 31, 2018 and 2017 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,			
	2018		2017	
	Gross	Net	Gross	Net
Kansas				
Productive Wells	1	0.90	1	0.15
Dry Holes	4	1.50	—	—

Productive Wells

As of December 31, 2018, the Company held a working interest in 199 gross wells, including interest in 5 properties operated by others, and 192 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.

Developed and Undeveloped Oil and Gas Acreage

As of December 31, 2018 the Company owned and operated 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	13,870	11,447	1,432	295	15,302	11,742

The following table identifies the number of gross and net undeveloped acres as of December 31, 2018 that will expire, by year, unless production is established before lease expiration or unless the lease is renewed.

	2021	Total
Gross Acres	1,432	1,432
Net Acres	295	295

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 American 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 American during the fiscal years ended December 31, 2018 and December 31, 2017 are set forth below.

For the Quarters Ending	High	Low
March 31, 2018	$ 1.02	$ 0.59
June 30, 2018	$ 0.94	$ 0.60
September 30, 2018	$ 2.47	$ 0.72
December 31, 2018	$ 1.33	$ 0.70
March 31, 2017	$ 0.76	$ 0.37
June 30, 2017	$ 1.56	$ 0.39
September 30, 2017	$ 0.83	$ 0.55
December 31, 2017	$ 1.19	$ 0.57

Holders

As of March 25, 2019, the number of shareholders of record of the Company's common stock was 284 and management believes that there are approximately 5,000 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 2018 or 2017 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 2018, 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 2018 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 2018.

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 income from continuing operations of $442,000 or $0.04 per share in 2018 compared to a net loss of $(603,000) or $(0.06) per share in 2017.

The Company realized revenues of approximately $5.9 million in 2018 compared to $4.7 million in 2017. During 2018, revenues increased approximately $1.2 million of which $1.4 million of this increase related to a $14.05 per barrel increase in the average oil price received from $45.43 per barrel received in 2017 to $59.48 per barrel received in 2018. This was partially offset by a $192,000 decrease related to a decrease in oil sales volumes from 102.4 MBbl in 2017 to 98.2 MBbl in 2018. The more significant production declines were experienced in the Albers, Albers B, Coddington, Croffoot B, McElhaney, McElhaney A, Veverka B, and Veverka C leases. These decreases were primarily due to natural declines. These production declines were partially offset by certain production increases as a result of polymers performed in late Q2 and early Q3 of 2018 and completion of the BSU #1-30 well in Q4 2018.

The Company's production costs and taxes were approximately $3.6 million in 2018 compared to $3.4 million in 2017. The $147,000 increase in 2018 was primarily related to a $50,000 increase in chemical cost, a $44,000 increase in compensation expense as a result of reinstating compensation to pre-reduction levels as a result of increased oil prices, and a $37,000 increase in pumping charges, partially offset by a $99,000 decrease primarily related to an amendment to the 2016 Delaware franchise taxes recorded in the third quarter of 2017. The remainder of the increase was primarily related to miscellaneous repairs to wells, equipment, and roads.

Depreciation, depletion, and amortization was approximately $795,000 in 2018 compared to $862,000 in 2017. The $67,000 decrease in 2018 was primarily due to a $42,000 decrease related to a decrease in the oil and gas depletion rate due principally to an increase in reserve volume at December 31, 2018 compared to reserve volumes at December 31, 2017, and a $33,000 decrease related to lower sales volumes.

The Company's general and administrative cost was approximately $1.25 million in 2018 compared to $1.17 million in 2017. The $74,000 increase in 2018 was primarily related to a $39,000 increase in compensation expense as a result of reinstating compensation to pre-reduction levels as a result of increased oil prices, a $31,000 increase in legal and accounting costs, and a $30,000 increase in engineering and reserve valuation consulting costs.

The Company performed its assessment for impairment during 2017 and 2018. No impairments of oil and gas properties or other assets resulted from the Company's assessment.

Net interest expense was $5,000 in 2018 compared to $53,000 in 2017. The $48,000 decrease during 2018 was primarily related to a decrease in the credit facility, interest paid in 2017 related to the amendment of the 2016 franchise taxes, and a reduction in loan amortization costs. The Company's credit facility was paid off in February 2017.

Other income (expense) was $157,000 in 2018 compared to $0 in 2017. The amount recorded in 2018 was primarily due to write off of Accounts payable – other. This write off occurred as the Company determined that the outstanding balance was not recoverable against the Company by operation of applicable statutes of limitation or prescription.

During 2018 and 2017, the Company did not have any open derivative positions.

The Company recorded an income tax benefit of $17,000 and $242,000 in 2018 and 2017, respectively. The income tax benefit was due to releasing the allowance related to its MTC as a result of the 2017 Tax Act. The Company recorded an allowance on the remaining deferred tax asset at December 31, 2018 and December 31, 2017 primarily due to cumulated losses incurred during the 3 years ended December 31, 2017.

Liquidity and Capital Resources

At December 31, 2018, the Company had a revolving credit facility with Prosperity Bank. This has historically been 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 $50 million or the Company's borrowing base in effect from time to time. As of December 31, 2018, the Company's borrowing base was $3 million, subject to a credit limit based on current covenants of approximately $2.74 million. The credit facility is secured by substantially all of the Company's producing and non-producing oil and gas properties. The credit facility includes certain covenants with which the Company is required to comply. At December 31, 2018, these covenants include the following: (a) Current Ratio > 1:1; (b) Funded Debt to EBITDA < 3.5x; and (c) Interest Coverage > 3.0x. At December 31, 2018, the interest rate on this credit facility was 6.00%. The Company was in compliance with all covenants as of December 31, 2018.

On August 24, 2018, 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 increase the borrowing base to $3 million, subject to a credit limit based on current covenants of approximately $2.74 million. 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 5.50% at the date of the amendment. The maximum line of credit of the Company under the Prosperity Bank credit facility remained $50 million.

On March 21, 2018, the Company's senior credit facility with Prosperity Bank after Prosperity Bank's review of the Company's owned producing properties was amended to increase the borrowing base to $2 million and the maturity date was extended to July 31, 2020. The borrowing base remained subject to the existing periodic redetermination provisions in the credit facility. The interest rate remained prime plus 0.50% per annum. This rate was 5.00% at the date of the amendment. The maximum line of credit of the Company under the Prosperity Bank credit facility remained $50 million.

The Company had zero borrowings under the facility at December 31, 2018 and December 31, 2017. The next borrowing base review will take place in April 2019.

Net cash provided by operating activities by continuing operations was $1.3 million in 2018, and $113,000 in 2017. Cash flow used in working capital during 2018 was $79,000, and $319,000 during 2017. The change in cash used in operating activities during 2018 was primarily related to increased revenues as a result of higher oil prices, and changes in working capital.

Net cash used in investing activities was $1.0 million in 2018 compared to $179,000 in 2017. The $844,000 increase in cash used in investing activities during 2018 was due primarily to drilling and polymer costs incurred during 2018.

Net cash used by in financing activities was $42,000 in 2018 compared to net cash provided by financing activities was $134,000 in 2017. The $176,000 decrease in net cash provided by financing activities in 2018 was primarily related to proceeds from the Company's rights offering which closed on February 2, 2017.

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

Effective January 1, 2018, the Company adopted ASU 2014-09 *Revenue from Contracts with Customers*. The Company identifies the contracts with each of its customers and the separate performance obligations associated with each of these contracts. Revenues are recognized when the performance obligations are satisfied and when it transfers control of goods or services to customers at an amount that reflects the consideration to which it expects to be entitled in exchange for those goods or services.

Crude oil is sold on a month-to-month contract at a price based on an index price from the purchaser, net of differentials. Crude oil that is produced is stored in storage tanks. The Company will contact the purchaser and request them to pick up the crude oil from the storage tanks. When the purchaser picks up the crude from the storage tanks, control of the crude transfers to the purchaser, the Company's contractual obligation is satisfied, and revenues are recognized. The sales of oil represent the Company's share of revenues net of royalties and excluding revenue interests owned by others. When selling oil on behalf of royalty owners or working interest owners, the Company is acting as an agent and thus reports revenues on a net basis. Fees and other deductions incurred prior to transfer of control are recorded as production costs. Revenues are reported net of fees and other deductions incurred after transfer of control.

Electricity from the Company's methane facility was sold on a long term contract. There were no specific volumes of electricity that were required to be delivered under this contract. Electricity passed through sales meters located at the Carter Valley landfill site, at which time control of the electricity transferred to the purchaser, the Company's contractual obligation was satisfied, and revenues were recognized. The Company sold its methane facility and generation assets on January 26, 2018 and therefore will not recognize revenues associated with any sales volumes after that date. Revenues associated with the methane facility are included in Discontinued Operations.

The Company operates certain salt water disposal wells, some of which accept water from third parties. The contracts with the third parties primarily require a flat monthly fee for the third parties to dispose water into the wells. In some cases, the contract is based on a per barrel charge to dispose water into the wells. There is no requirement under the contracts for these third parties to use these wells for their water disposal. If the third parties do dispose water into the Company operated wells in a given month, the Company has met its contractual obligations and revenues are recognized for that month.

The following table presents the disaggregated revenue by commodity for the years ended December 31, 2018, and 2017 (in thousands):

	Year Ended December 31, 2018	Year Ended December 31,2017
Revenue (in thousands):		
Crude oil	$ 5,840	$ 4,653
Salt water disposal fees	31	30
Total	$ 5,871	$ 4,683

There were no natural gas imbalances at December 31, 2018 or December 31, 2017.

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 $23,000 and $0 in unevaluated properties as of December 31, 2018 and 2017, 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.

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, 2018 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.

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.

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.

Recent Accounting Pronouncements

In February 2016, the FASB issued Update 2016-02 *Leases (Topic 842)*. This guidance was issued to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. This guidance is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early application of the amendments in this Update is permitted for all entities. The Company has identified each of its leases and determined the impact of this new guidance on each of the identified leases. Upon adoption on January 1, 2019, the Company anticipates that it will record right-of-use assets and liabilities associated with operating leases of approximately $100,000.

Table of Contents

Contractual Obligations

The following table summarizes the Company’s contractual obligations due by period as of December 31, 2018 (in thousands):

Contractual Obligations	Total	2019	2020	2021
Long-Term Debt Obligations[1]	$ 124	$ 51	$ 47	$ 26
Operating Lease Obligations	82	49	33	—
Estimated Interest on Long-Term Debt Obligations	12	8	3	1
Total	$ 218	$ 108	$ 83	$ 27

(1) The credit facility with Prosperity Bank had a zero balance at December 31, 2018.

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 2018 ranged from a low of $43.79 per barrel to a high of $65.70 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 2018 or 2017, but may participate in derivative activities in the future.

Interest Rate Risk

At December 31, 2018, the Company had debt outstanding of approximately $124,000, none of which was owed on its credit facility with Prosperity Bank. As of December 31, 2018, the interest rate on the credit facility was variable at a rate equal to prime plus 0.50% per annum. The Company’s credit facility interest rate at December 31, 2018 was 6.00%. The Company’s remaining debt of $124,000 has fixed interest rates ranging from 5.0% to 6.5%.

The annual impact on interest expense and the Company’s cash flows of a 10% increase in the interest rate on the credit facility would be approximately zero assuming borrowed amounts under the credit facility remained at the same amount owed as of December 31. The Company did not have any open derivative contracts relating to interest rates at December 31, 2018 or 2017.

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.

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.

Management’s 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:

- 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, 2018. 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, 2018.

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

During the year ended December 31, 2018, there have been no changes to the Company’s system of internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company’s system of controls 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.

ITEM 9B. OTHER INFORMATION

On January 2, 2019, 4,962 common shares were issued in the aggregate to the Company’s three directors and CFO and interim CEO. This issuance will result in compensation expense of approximately $4,714 to be recorded during the quarter ended March 31, 2019.

In January 2019, the Company sold its equipment inventory for $150,000. The Company will record a gain on this sale of $45,000 during the quarter ended March 31, 2019.

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	3/27/2007	48
Peter E. Salas	Director;	10/8/2002	64
	Chairman of the Board	10/21/2004	
Richard M. Thon	Director	11/22/2013	63
Michael J. Rugen	Chief Financial Officer;	9/28/2009	58
	Chief Executive Officer (interim)	6/24/2013	
Cary V. Sorensen	Vice-President; General Counsel; Secretary	7/9/1999	70

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. 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.

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. 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 270,000 employees worldwide, and provides food services, facilities management, and uniform and career apparel to health care institutions, universities, and businesses in 23 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. 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.

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 35 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:

(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:

a. 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; and

b. Peter E. Salas, a director of the Company and Chairman of the Board of the Company was the chief executive officer of Boston Restaurant Associates, Inc. when that company filed a Chapter 11 reorganization plan under federal bankruptcy laws on May 20, 2015. The plan of reorganization became effective on August 31, 2015 and Mr. Salas has remained the chief executive officer and sole director of that company since the reorganization

(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 ("CFTC"), 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;

(6) Was found by a court of competent jurisdiction in a civil action or by the 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 2018, 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., 8000 E. Maplewood Ave., Suite 130, Greenwood Village, CO 80111.

Audit Committee

During 2018, 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 American Rules. Each of the members of the Audit Committee met the independence and experience requirements of the NYSE American Rules, the applicable Securities Laws, and the regulations and rules promulgated by the SEC. The Audit Committee met each quarter and a total of four (4) times in Fiscal 2018 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 American 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 2018, 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.

Table of Contents

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, other executive officers, and employees whose compensation exceeded $100,000 during fiscal years ended December 31, 2018 and December 31, 2017.

SUMMARY COMPENSATION TABLE

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards ($)	All Other Compensation[2] ($)	Total ($)
Michael J. Rugen,	2018	184,213	21,821	15,097	7,482	228,613
Chief Financial Officer	2017	163,857	19,276	9,149	6,673	198,955
Chief Executive Officer (interim)[3]						
Cary V. Sorensen,	2018	87,050	—	—	3,550	90,600
General Counsel	2017	81,900	—	—	3,454	85,354

(2) The amounts in this column consist of the Company's matching contributions to its 401 (k) plan 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 bonus and stock award information for Mr. Rugen for 2018 and 2017 represents his compensation for his services as CEO.

Outstanding Equity Awards at Fiscal Year-End

	OPTION AWARDS			
Name	Number of securities underlying unexercised options exercisable	Number of securities underlying unexercised options unexercisable	Option exercise price	Option expiration date
Michael J. Rugen	—	—	$ —	
Cary V. Sorensen	—	—	$ —	

Option and Award Exercises

No other options were exercised during 2018 or 2017.

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.

On February 19, 2015, in response to the 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 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. In May 2018, oil prices as so calculated exceeded $70 and compensation reverted 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 as described above. 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. In May 2018, oil prices as so calculated exceeded $70 and compensation reverted 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 from the $91,000 salary level will be reimbursed to Mr. Sorensen if he is still employed by the Company.

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 2018 were Matthew K. Behrent and Richard M. Thon, with Mr. Thon acting as Chairman. Messrs. Behrent and Thon meet the current independence standards established by the NYSE American 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 American 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, stock, 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.

In May 2018, oil prices as so calculated exceeded $70 and executive compensation reverted to the levels in place before the compensation reductions became effective. 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 2018.

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 or common stock 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 that separate 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 2018.

On February 19, 2015, in response to the 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 compensation of the Company's directors. The reductions on the directors' compensation 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 then their compensation will revert to pre-reduction levels. In May 2018, oil prices as so calculated exceeded $70 and compensation reverted 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 from pre-reduction compensation levels will be reimbursed to the directors if they are still directors of the Company.

DIRECTOR COMPENSATION FOR FISCAL 2018

Name	Fees earned or paid in cash ($)	Stock awards compensation[4] ($)	Total ($)
Matthew K. Behrent	$ 12,012	$ 2,300	$ 14,312
Richard M. Thon	$ 12,012	$ 2,300	$ 14,312
Peter E. Salas	$ 12,012	$ 2,300	$ 14,312

(4) 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 11 Stock and 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, 2018 for information on the relevant valuation assumptions.

As of December 31, 2018, Mr. Behrent held 5,625 unexercised options; Mr. Salas held 5,625 unexercised options; and Mr. Thon held 5,625 unexercised options. The number of unexercised options have been adjusted to reflect the impact of the 1 for 10 reverse stock split approved at the shareholder meeting dated March 21, 2016, effective with trading on March 24, 2016.

Table of Contents

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

The following table sets forth the shareholdings of those persons who own more than 5% of the Company's common stock as of March 25, 2019 with these computations being based upon 10,644,252 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 26, 2018.

FIVE PERCENT STOCKHOLDERS [5]

Name and Address	Title	Number of Shares Beneficially Owned	Percent of Class
Dolphin Offshore Partners, L.P. c/o Dolphin Mgmt. Services, Inc. P.O. Box 16867 Fernandina Beach, FL 32035	Stockholder	5,294,241	49.7%

(5) 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 25, 2019.

SECURITY OWNERSHIP OF DIRECTORS AND OFFICERS

Name and Address	Title	Number of Shares Beneficially Owned [6]	Percent of Class [7]
Matthew K. Behrent (8)	Director	65,900	Less than 1%
Michael J. Rugen (9)	Chief Executive Officer (interim); Chief Financial Officer	51,857	Less than 1%
Peter E. Salas (10)	Director; Chairman of the Board	5,299,241	49.8%
Cary V. Sorensen (11)	Vice President; General Counsel; Secretary	23,623	Less than 1%
Richard M. Thon (12)	Director	34,000	Less than 1%
All Officers and Directors as a group (13)		5,474,621	51.4%

(6) 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 25, 2019.

(7) Calculated pursuant to Rule 13d-3(d) under the Securities Exchange Act of 1934 based upon 10,644,252 shares of common stock being outstanding as of March 25, 2019. Shares not outstanding that are subject to options or warrants exercisable by the holder thereof within 60 days of March 25, 2019 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.

(8) Consists of 60,900 shares held directly and vested, fully exercisable options to purchase 5,000 shares.

(9) Consists of 51,857 shares held directly.

(10) Consists of directly, vested, fully exercisable options to purchase 5,000 shares, 6,000 shares held individually, and 5,288,241 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.

(11) Consists of 23,623 shares held directly.

(12) Consists of 29,000 shares held directly and vested, fully exercisable options to purchase 5,000 shares.

(13) Consists of 171,380 shares held directly by directors and management, 5,288,241 shares held by Dolphin and vested, and fully exercisable options to purchase 15,000 shares.

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, 2018.

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 approve by security holders [14]	16,875	$ 3.18	301,927
Equity compensation plans not approved by security holders	—	—	—
Total	16,875	$ 3.18	301,927

(14) Refers to Tengasco, Inc. 2018 Stock Incentive Plan (the "2018 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 2018 Plan contains the same substantive terms of the Company's previous stock incentive plan adopted in October, 2000 and as thereafter amended until its expiration on January 10, 2018. The 2018 Plan provided an aggregate number of shares for which shares, options, and stock appreciation rights may be issued under the 2018 Plan equal to the number of shares that were available in the previous plan upon its expiration. The 2018 Plan was approved by a majority of the Company's shareholders acting on written consent and the shares thereunder were subject to Registration Statement on Form S-8 filed August 27, 2018.

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

Certain Transactions

During the 4th quarter of 2018, the Company acquired all of Hoactzin's interest in the drilling program wells for $134,690 as reported below. The acquisition was authorized by the two nonrelated party directors in accordance with the Company's related party transaction policy, and was made on the same terms offered to all participants and accepted by four of the five drilling program participants other than Hoactzin electing to sell their interest to the Company. One participant did not accept the Company's offer to purchase its interest. Other than that acquisition, there have been no material transactions, series of similar transactions or currently proposed transactions entered into during 2018 and 2017, 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, 2018, the Company describes two transactions of the type described above, that the Company entered into with Hoactzin in 2007 that remained in existence during 2017 and for a portion of the year in 2018. Those two transactions are the "net profits agreement" and the "drilling programs". In January 2018, the Company sold its methane facility assets, thereby ending the net profits agreement at the Methane Project. In November 2018, the Company acquired Hoactzin's interest in the Ten Well Program for $131,290. As noted above, 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 two 2007 transactions between the Company and Hoactzin are described in Item 1, Business.

The approximate dollar value of the amount of Hoactzin's interest in each of these two 2007 transactions during each of the years 2017 and a portion of 2018 was as follows: (1) Ten Well Program - $33,000 in 2018; and $31,000 in 2017 (calculated as the total payments attributable to Hoactzin for its program interest); and (2) Net Profits agreement at the Methane Project - $0 in both 2018 and 2017.

In addition to the two 2007 transactions, Hoactzin also owned 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. In November 2018, the Company acquired Hoactzin's interest in the 6 Well Program for $3,400. The approximate dollar value of the amount of Hoactzin's interest in the 6 Well Program was $9,000 in 2018; and $10,000 in 2017 (calculated as the total payments attributable to Hoactzin for its program interest). Following the acquisition of all Hoactzin's drilling program interests in November 2018, there will be no interest of Hoactzin in the ten well or six well drilling programs in any future period.

In addition to the above, one transaction of the type described above was entered into in 2007 but has expired by its own terms. 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 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.

As operator during the term of the Management Agreement that expired in 2012, 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. As a result of the operations performed by Hoactzin in late 2009 and 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, 2017 in the amount of $159,000. The Company has recorded the Hoactzin-related payables and the corresponding receivable from Hoactzin as of December 31, 2017 in its Consolidated Balance Sheets under "Accounts payable – other" and "Accounts receivable – related party". However, Hoactzin had 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, 2017. 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" are $0 at December 31, 2017. At year-end 2018, the Company has determined that the outstanding balances under these vendor contracts for services or materials provided in 2009 and 2010 are not recoverable against the Company by operation of applicable statutes of limitation or prescription, and consequently, these amounts have been removed from the Company's balance sheet at December 31, 2018. This removal also resulted in the Company recording other income in 2018 in the amount of $159,000.

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 called 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. On July 14, 2015, the federal district court in the Eastern District of Louisiana affirmed the civil penalty without reduction. The Company did not further appeal. In the third quarter of 2015, the Company paid the civil penalty and statutory interest thereon from funds borrowed under its credit facility. In the fourth quarter of 2015, the Company received a return of the cash collateral previously provided to RLI Insurance Company. The Company has not advanced any funds to pay any obligations of Hoactzin and no borrowing capability of the Company has been used in connection with its obligations under the Management Agreement, except for those funds used to pay the civil penalty and interest thereon.

During the second quarter of 2015, the Company received from Hoactzin a copy of an internal analysis prepared by Hoactzin setting out certain issues that Hoactzin may consider to form the basis of operational and other claims against the Company primarily under the Management Agreement. This analysis raised issues other than the "Incident of Non-Compliance" discussed above. The Company is discussing this analysis, as well as the civil penalty discussed above, with Hoactzin in an effort to determine whether there is possibility of a reasonable resolution of some or all of these matters on a negotiated basis.

Director Independence

The Rules of the NYSE American (the "NYSE American 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 American 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 American Rule 803(b)(2)(c). The Board of Directors has determined that the Company's directors, Matthew K. Behrent, Hughree F. Brooks, and Richard M. Thon, are independent as defined by the NYSE American Rules, and that Matthew K. Behrent and Richard M. Thon 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. Mr. Brooks did not stand for reelection as a director at the annual meeting of shareholder of the Company held on December 12, 2017 and his term of office as a director ended at the conclusion of the meeting. 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 American 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;

The Director has received, or has an immediate family member [15] 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[16] 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.

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.

---

(15) 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).

(16) 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.

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 independent registered public accounting firm, 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, 2018 and December 31, 2017. Hein & Associates LLP ("Hein") performed these services for the first three quarters of 2017. In November 2017, Hein combined with Moss Adams LLP ("Moss Adams") and Moss Adams was selected by the Audit Committee to continue as the Company's independent accountants.

AUDIT AND NON-AUDIT FEES

	2018 Moss Adams	2017 Moss Adams	2017 Hein
Audit Fees	$ 117,600	$ 73,500	$ 37,800
Audit-Related Fees	—	—	—
Tax Fees	—	—	—
All Other Fees	3,599	—	—
Total Fees	$ 121,199	$ 73,500	$ 37,800

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 2018 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 Moss Adams were compatible with maintaining its independence and concluded they were.

Table of Contents

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	Amended and Restated Certificate of Incorporation as of March 23, 2016 (Incorporated by reference to Exhibit 3 to registrant's Report on Form 10-Q for the period ended September 30, 2016 filed November 14, 2016).
3.2	Amended and Restated Bylaws as of November 13, 2014 (Incorporated by reference to Exhibit 3.2 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2014 filed on March 30, 2015).
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 99.A to registrant's Definitive Proxy Statement pursuant to Schedule 14a filed May 2, 2011).
10.1	Tengasco, Inc. 2018 Incentive Stock Plan (Incorporated by reference to Appendix A to the Registrant's Information Statement on Schedule 14C filed with the Securities and Exchange Commission on August 27, 2018)
10.2	Amended and Restated Loan Agreement between Tengasco, Inc. and Prosperity Bank, effective March 16, 2017 (Incorporated by reference to Exhibit 10.14 to the registrant's Annual Report on form 10-K for the year ended December 31, 2017 filed March 28, 2018).
10.3	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"]).
10.4	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).
10.5	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).
10.6	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).
14	Code of Ethics (Incorporated by reference to Exhibit 14 to the registrant's Annual Report on Form 10-K filed March 30, 2004).

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, 2018
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*	XBRL Taxonomy Presentation Linkbase Document

* Exhibit filed with this Report

Table of Contents

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 28, 2019

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 Matthew K. Behrent	Director	March 28, 2019
s/ Peter E. Salas Peter E. Salas	Director	March 28, 2019
s/ Richard M. Thon Richard M. Thon	Director	March 28, 2019
s/ Michael J. Rugen Michael J. Rugen	Chief Executive Officer and Principal Financial Accounting Officer	March 28, 2019

Tengasco, Inc.
and Subsidiaries

Consolidated Financial Statements
Years Ended December 31, 2018, and 2017

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of
Tengasco, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Tengasco and subsidiaries (the "Company") as of December 31, 2018 and 2017, the related consolidated statements of operations, stockholders' equity, and cash flows for the years then ended, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as of December 31, 2018 and 2017, and the consolidated results of its operations and its cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting 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.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Moss Adams LLP

Denver, Colorado
March 28, 2019

We have served as the Company's auditor since 2017.

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

	December 31, 2018	December 31, 2017
Assets		
Current		
Cash and cash equivalents	$ 3,115	$ 185
Accounts receivable, less allowance for doubtful accounts of $0 and $14	533	517
Accounts receivable-related party, less allowance for doubtful accounts of $0 and $159	—	—
Inventory	464	541
Prepaid expenses	235	130
Discontinued operations included in current assets	—	121
Total current assets	4,347	1,494
Loan fees, net	9	13
Oil and gas properties, net (*full cost accounting method*)	4,804	4,720
Other property and equipment, net	190	135
Accounts receivable - noncurrent	130	242
Other noncurrent assets	4	4
Discontinued operations included in non-current assets	—	1,497
Total assets	$ 9,484	$ 8,105

See accompanying Notes to Consolidated Financial Statements

Table of Contents

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

	December 31, 2018	December 31, 2017
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable – trade	$ 132	$ 181
Accounts payable – other	—	159
Accrued liabilities	282	187
Current maturities of long-term debt	51	41
Asset retirement obligation - current	83	—
Discontinued operations included in current liabilities	—	43
Total current liabilities	548	611
Asset retirement obligation - non current	2,096	2,270
Long term debt, less current maturities	73	49
Total liabilities	2,717	2,930
Commitments and contingencies (Note 9)		
Stockholders' equity		
Preferred stock, 25,000,000 shares authorized:		
Series A Preferred stock, $0.0001 par value, 10,000 shares designated; 0 shares issued and outstanding	—	—
Common stock, $.001 par value: authorized 100,000,000 Shares; 10,639,290 and 10,619,924 shares issued and outstanding	11	11
Additional paid in capital	58,276	58,253
Accumulated deficit	(51,520)	(53,089)
Total stockholders' equity	6,767	5,175
Total liabilities and stockholders' equity	$ 9,484	$ 8,105

See accompanying Notes to Consolidated Financial Statements

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

	Year ended December 31,	
	2018	**2017**
Revenues		
Oil and gas properties	$ 5,871	$ 4,683
Total revenues	5,871	4,683
Cost and expenses		
Production costs and taxes	3,591	3,444
Depreciation, depletion, and amortization	795	862
General and administrative	1,245	1,171
Total cost and expenses	5,631	5,477
Net income (loss) from operations	240	(794)
Other income (expense)		
Net interest expense	(5)	(53)
Gain on sale of assets	33	2
Other income	157	—
Total other income (expense)	185	(51)
Income (loss) from operations before income tax	425	(845)
Deferred income tax benefit	17	242
Net income (loss) from continuing operations	442	(603)
Net income from discontinued operations	1,127	29
Net income (loss)	$ 1,569	$ (574)
Net income (loss) per share - basic and fully diluted		
Continuing operations	$ 0.04	$ (0.06)
Discontinued operations	$ 0.11	$ —
Shares used in computing earnings per share		
Basic and fully diluted	10,628,170	10,081,218

See accompanying Notes to Consolidated Financial Statements

Table of Contents

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

	Common Stock		Paid-in	Accumulated	
	Shares	**Amount**	**Capital**	**Deficit**	**Total**
Balance, December 31, 2016	6,097,723	$ 6	$ 55,787	$ (52,515)	$ 3,278
Net loss	—	—	—	(574)	(574)
Compensation expense related to stock issued	23,503	—	14	—	14
Shares issued for rights offering	4,498,698	5	2,452	—	2,457
Balance, December 31, 2017	10,619,924	$ 11	$ 58,253	$ (53,089)	$ 5,175
Net income	—	—	—	1,569	1,569
Compensation expense related to stock issued	19,366	—	23	—	23
Balance, December 31, 2018	10,639,290	$ 11	$ 58,276	$ (51,520)	$ 6,767

See accompanying Notes to Consolidated Financial Statements

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

	Year Ended December 31, 2018	Year Ended December 31, 2017
Operating activities		
Net income (loss) from continuing operations	$ 442	$ (603)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities		
Depreciation, depletion, and amortization	795	862
Amortization of loan fees-interest expenses	4	20
Accretion of discount on asset retirement obligation	141	141
(Gain) loss on asset sales	(33)	(2)
Compensation and services paid in stock / stock options	23	14
Changes in assets and liabilities:		
Accounts receivable	96	(318)
Inventory, prepaid expense, and other assets	(28)	203
Accounts payable	(58)	(78)
Accrued liabilities	(64)	(73)
Settlement on asset retirement obligations	(25)	(53)
Net cash provided by operating activities - continuing operations	1,293	113
Net cash provided by operating activities - discontinued operations	44	41
Net cash provided by operating activities	1,337	154
Investing activities		
Additions to oil and gas properties	(1,011)	(169)
Proceeds from sale of oil and gas properties	7	7
Additions to other property & equipment	(27)	(17)
Proceeds from sale of other property & equipment	8	—
Net cash used in investing activities - continuing operations	(1,023)	(179)
Net cash provided by investing activities - discontinued operations	2,658	—
Net cash provided by (used in) investing activities	1,635	(179)
Financing activities		
Proceeds from stock issuance in rights offering	—	2,699
Cost of stock issuance in rights offering	—	(102)
Proceeds from borrowings	100	400
Repayment of borrowings	(142)	(2,854)
Loan fees	—	(9)
Net cash provided by (used in) financing activities - continuing operations	(42)	134
Net cash provided by (used in) financing activities - discontinued operations	—	—
Net cash provided by (used in) financing activities	(42)	134
Net change in cash and cash equivalents	2,930	109
Cash and cash equivalents, beginning of period	185	76
Cash and cash equivalents, end of period	$ 3,115	$ 185
Supplemental cash flow information:		
Cash interest payments	$ —	$ 33
Supplemental non-cash investing and financing activities:		
Financed company vehicles	$ 136	$ 81
Cost of stock issuance in rights offering	$ —	$ (140)
Asset retirement obligations incurred	$ 7	$ 1
Revisions to asset retirement obligations	$ (198)	$ 138
Capital expenditures included in accounts payable and accrued liabilities	$ 9	$ —

See accompanying Notes to Consolidated Financial Statements

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 exploration and production is in Kansas.

The Company's wholly-owned subsidiary, Tengasco Pipeline Corporation ("TPC") owned and operated a 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 assets on August 16, 2013.

The Company's wholly-owned subsidiary, Manufactured Methane Corporation ("MMC") operated 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 sold all its methane facility assets on January 26, 2018. (See Note 5. Discontinued Operations)

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

Effective January 1, 2018, the Company adopted ASU 2014-09 Revenue from Contracts with Customers. The Company identifies the contracts with each of its customers and the separate performance obligations associated with each of these contracts. Revenues are recognized when the performance obligations are satisfied and when it transfers control of goods or services to customers at an amount that reflects the consideration to which it expects to be entitled in exchange for those goods or services.

Crude oil is sold on a month-to-month contract at a price based on an index price from the purchaser, net of differentials. Crude oil that is produced is stored in storage tanks. The Company will contact the purchaser and request them to pick up the crude oil from the storage tanks. When the purchaser picks up the crude from the storage tanks, control of the crude transfers to the purchaser, the Company's contractual obligation is satisfied, and revenues are recognized. The sales of oil represent the Company's share of revenues net of royalties and excluding revenue interests owned by others. When selling oil on behalf of royalty owners or working interest owners, the Company is acting as an agent and thus reports revenues on a net basis. Fees and other deductions incurred prior to transfer of control are recorded as production costs. Revenues are reported net of fees and other deductions incurred after transfer of control.

Electricity from the Company's methane facility was sold on a long term contract. There were no specific volumes of electricity that were required to be delivered under this contract. Electricity passed through sales meters located at the Carter Valley landfill site, at which time control of the electricity transferred to the purchaser, the Company's contractual obligation was satisfied, and revenues were recognized. The Company sold its methane facility and generation assets on January 26, 2018 and therefore will not recognize revenues associated with any sales volumes after that date. Revenues associated with the methane facility are included in Discontinued Operations. (See Note 5. Discontinued Operations)

The Company operates certain salt water disposal wells, some of which accept water from third parties. The contracts with the third parties primarily require a flat monthly fee for the third parties to dispose water into the wells. In some cases, the contract is based on a per barrel charge to dispose water into the wells. There is no requirement under the contracts for these third parties to use these wells for their water disposal. If the third parties do dispose water into the Company operated wells in a given month, the Company has met its contractual obligations and revenues are recognized for that month.

The following table presents the disaggregated revenue by commodity for the years ended December 31, 2018 and 2017 (in thousands):

	Year Ended December 31, 2018	Year Ended December 31, 2017
Revenue (in thousands):		
Crude oil	$ 5,840	$ 4,653
Salt water disposal fees	31	30
Total	$ 5,871	$ 4,683

There were no natural gas imbalances at December 31, 2018 or December 31, 2017.

Cash and Cash Equivalents

Cash and cash equivalents include temporary cash investments with a maturity of ninety days or less at date of purchase.

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 quarterly per barrel cost for the quarter ended December 31, 2018 and December 31, 2017. During 2018, the Company included production costs and taxes in its calculation of estimated cost. During 2017, the Company included production costs and taxes, allocated general and administrative costs, depletion, and allocated interest in its calculation of estimated cost. The Company made this change as it believes that excluding allocated general and administrative costs, depletion, and interests provides a better estimate of its cost of oil inventory. The market component is calculated using the average December 2018 and December 2017 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, 2018 and December 31, 2017, inventory consisted of the following (in thousands):

	December 31,	
	2018	**2017**
Oil – carried at cost	$ 359	$ 436
Equipment and materials – carried at market	105	105
Total inventory	$ 464	$ 541

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 $23,000 and $0 in unevaluated properties as of December 31, 2018 and 2017, 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. The Company performed its ceiling tests during 2017 and 2018, resulting in no impairments of its oil and gas properties.

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.

Manufactured Methane Facilities

The Manufactured Methane facilities were placed into service in April 2009 and were being depreciated using the straight-line method over the useful life based on the estimated landfill closure date of December 2041. The Company sold all its methane facility assets, except the applicable U.S. patent, on January 26, 2018. (See Note 5. Discontinued Operations)

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 $23,000 in 2018 and $14,000 in 2017.

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, 2018 and 2017. At December 31, 2018 and 2017, accounts receivable consisted of the following (in thousands):

	December 31,	
	2018	2017
Revenue	$ 396	$ 479
Tax	129	—
Joint interest	8	23
Other	—	29
Allowance for doubtful accounts	—	(14)
Total accounts receivable	$ 533	$ 517

At year-end 2018, the Company removed the $159,000 from Accounts receivable-related party and also from the associated allowance for doubtful accounts. This removal occurred as the Company determined that the outstanding balance of the associated payable recorded in Accounts payable – other was not recoverable against the Company by operation of applicable statutes of limitation or prescription.

At December 31, 2018 and December 31, 2017, the Company recorded a tax related non-current receivable in the amount of $130,000 and $242,000, respectively. At September 30, 2018, based upon its expected recovery, the Company reclassified $121,000 of this tax related non-current receivable as a current receivable. At December 31, 2018, the increased the tax related current and non-current receivable by approximately $8,000 and $9,000, respectively. (See Note 13. Income Taxes)

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.

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.

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. The Company has never experienced any losses related to these balances.

The Company's primary business activities include oil sales to a limited number of customers in the state of Kansas. 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. 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 results of operations.

Revenue from the top two purchasers accounted for 85.6% and 13.8% of total revenues for year ended December 31, 2018. Revenue from the top two purchasers accounted for 84.6% and 14.8% of total revenues for year ended December 31, 2017. As of December 31, 2018 and 2017, two of the Company's oil purchasers accounted for 93.2% and 89.7%, respectively of accounts receivable, of which one oil purchaser accounted for 84.4% and 74.4%, respectively.

The amounts above exclude revenues and accounts receivable associated with Discontinued Operations. (see Note 5. Discontinued Operations)

Earnings per Common Share

The Company reports 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 the Company's basic and diluted earnings per share, (*in thousands except for share and per share amounts):*

	For the years ended December 31,	
	2018	**2017**
Income (numerator):		
Net income (loss) from continuing operations	$ 442	$ (603)
Net income from discontinued operations	1,127	29
Weighted average shares (denominator):		
Weighted average shares - basic	10,628,170	10,081,218
Dilution effect of share-based compensation, treasury method	—	—
Weighted average shares - dilutive	10,628,170	10,081,218
Income (loss) per share – Basic and Dilutive:		
Continuing operations	$ 0.04	$ (0.06)
Discontinued operations	$ 0.11	$ —

Options issued to the Company's directors in which the exercise price was higher than the average market price each quarter was also excluded from diluted shares as they would have been anti-dilutive (See Note 12. Stock and Stock Options). In addition, the shares that would be issued to employees and Company directors have also been excluded from this calculation. (See Note 9. Commitments and Contingencies)

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, 2018 and 2017.

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, 2018 and 2017, 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.

2. Recent Accounting Pronouncements

In February 2016, the FASB issued Update 2016-02 *Leases (Topic 842).* This guidance was issued to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. This guidance is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early application of the amendments in this Update is permitted for all entities. The Company has identified each of its leases and determined the impact of this new guidance on each of the identified leases. Upon adoption on January 1, 2019, the Company anticipates that it will record right-of-use assets and liabilities associated with operating leases of approximately $100,000.

3. Related Party Transactions

On September 17, 2007, Hoactzin Partners, L.P. (“Hoactzin”) subscribed to a drilling program offered by the Company consisting of wells to be drilled on the Company’s Kansas Properties (the “Program”). 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. Hoactzin was also conveyed a net profits interest in the MMC facility at the Carter Valley municipal solid waste landfill owned and operated by Republic Services, Inc. in Church Hill, Tennessee where the Company installed a propriety combination of advanced gas treatment technology to extract the methane component of the purchased gas stream (the “Methane Project”). The net profits interest owned by Hoactzin during 2017 was 7.5% of the net profits as defined by agreement and takes into account specific costs and expenses as well as gross gas revenues for the project. As a result of the startup costs, monthly operating expenses, and gas production levels experienced, no net profits as defined were realized during the period from the project startup in April, 2009 through January 26, 2018, the date the Company sold the Methane Project to a third party, for payment to Hoactzin under the net profits interest. In addition, during Company during the 4th quarter of 2018, the Company acquired all of Hoactzin’s interest in the drilling program wells for $134,690.

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 entered into a transition agreement with Hoactzin whereby the Company no longer performs operations, but administratively assists Hoactzin in becoming operator of record of these wells and transferring all 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.

As operator during the term of the Management Agreement that expired in 2012, 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. As a result of the operations performed by Hoactzin in late 2009 and 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, 2017 in the amount of $159,000. The Company has recorded the Hoactzin-related payables and the corresponding receivable from Hoactzin as of December 31, 2017 in its Consolidated Balance Sheets under “Accounts payable – other” and “Accounts receivable – related party”. However, Hoactzin had 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, 2017. 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” are $0 at December 31, 2017. At year-end 2018, the Company has determined that the outstanding balances under these vendor contracts for services or materials provided in 2009 and 2010 are not recoverable against the Company by operation of applicable statutes of limitation or prescription, and consequently, these amounts have been removed from the Company’s balance sheet at December 31, 2018. This removal also resulted in the Company recording other income in 2018 in the amount of $159,000.

4. Oil and Gas Properties

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

	December 31,	
	2018	**2017**
Oil and gas properties	$ 6,503	$ 5,704
Unevaluated properties	23	—
Accumulated depreciation, depletion and amortization	(1,722)	(984)
Oil and gas properties, net	$ 4,804	$ 4,720

During the years ended December 31, 2018 and 2017, the Company recorded depletion expense of $722,000 and $796,000, respectively.

5. Discontinued Operations

The following table sets forth information concerning Discontinued Operations: *(in thousands):*

	December 31,	
	2018	**2017**
Accounts receivable	$ —	$ 91
Other current assets	—	30
Discontinued operations included in current assets	$ —	$ 121
Property, plant, and equipment	$ —	$ 1,681
Accumulated depreciation, depletion, and amortization	—	(184)
Discontinued operations included in non-current assets	$ —	$ 1,497
Accounts payable - trade	$ —	$ 27
Accrued and other current liabilities	—	16
Discontinued operations included in current liabilities	$ —	$ 43

	For the years ended December 31,	
	2018	**2017**
Revenues	$ 6	$ 580
Production costs and taxes	(40)	(489)
Depreciation, depletion, and amortization	(4)	(62)
Interest income	—	—
Gain on sale of assets	1,165	—
Deferred income tax benefit	—	—
Net income (loss) from discontinued operations	$ 1,127	$ 29

The Discontinued Operations are related to the Manufactured Methane facilities. The Company sold all its methane facility assets, except the applicable U.S. patent, on January 26, 2018 for $2.65 million

6. Other Property and Equipment

Other property and equipment consisted of the following as of December 31, 2018: *(in thousands)*

Type	*Depreciable Life*	Gross Cost		Accumulated Depreciation		Net Book Value	
Machinery and equipment	5-7 yrs	$	20	$	20	$	—
Vehicles	2-5 yrs		293		103		190
Other	5 yrs		63		63		—
Total		$	376	$	186	$	190

Other property and equipment consisted of the following as of December 31, 2017: *(in thousands)*

Type	*Depreciable Life*	Gross Cost		Accumulated Depreciation		Net Book Value	
Machinery and equipment	5-7 yrs	$	20	$	20	$	—
Vehicles	2-5 yrs		318		183		135
Other	5 yrs		63		63		—
Total		$	401	$	266	$	135

The Company uses the straight-line method of depreciation for other property and equipment. During each of the years ended December 31, 2018 and 2017, the Company recorded depreciation expense of $73,000 and $66,000, respectively.

7. Long-Term Debt

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

	December 31,			
	2018		2017	
Note payable to a bank, with interest only payment until maturity.	$	—	$	—
Installment notes bearing interest at the rate of 5.0% to 6.5% per annum collateralized by vehicles with monthly payments including interest, insurance and maintenance of approximately $10		124		90
Total long-term debt		124		90
Less current maturities		(51)		(41)
Long-term debt, less current maturities	$	73	$	49

Future debt payments to unrelated entities as of December 31, 2018 consisted of the following: *(in thousands)*

	2019		2020		2021		Total	
Bank Credit Facility	$	—	$	—	$	—	$	—
Company Vehicles	$	51	$	47	$	26	$	124
Total	$	51	$	47	$	26	$	124

At December 31, 2018, the Company had a revolving credit facility with Prosperity Bank. This has historically been 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 $50 million or the Company's borrowing base in effect from time to time. As of December 31, 2018, the Company's borrowing base was $3 million, subject to a credit limit based on current covenants of approximately $2.74 million. The credit facility is secured by substantially all of the Company's producing and non-producing oil and gas properties. The credit facility includes certain covenants with which the Company is required to comply. At December 31, 2018, these covenants include the following: (a) Current Ratio > 1:1; (b) Funded Debt to EBITDA < 3.5x; and (c) Interest Coverage > 3.0x. At December 31, 2018, the interest rate on this credit facility was 6.00%. The Company was in compliance with all covenants during the quarter ended December 31, 2018.

On August 24, 2018, 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 increase the borrowing base to $3 million, subject to a credit limit based on current covenants of approximately $2.74 million. 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 5.50% at the date of the amendment. The maximum line of credit of the Company under the Prosperity Bank credit facility remained $50 million and the Company had no outstanding borrowing under the facility as of December 31, 2018. The next borrowing base review will take place in April 2019.

On March 21, 2018, the Company's senior credit facility with Prosperity Bank after Prosperity Bank's review of the Company's owned producing properties was amended to increase the borrowing base to $2 million and the maturity date was extended to July 31, 2020. The borrowing base remained subject to the existing periodic redetermination provisions in the credit facility. The interest rate remained prime plus 0.50% per annum. This rate was 5.00% at the date of the amendment. The maximum line of credit of the Company under the Prosperity Bank credit facility remained $50 million.

The Company had zero borrowings under the facility at December 31, 2018 and December 31, 2017. The next borrowing base review will take place in April 2019.

8. Liquidity

The Company incurred a net loss of approximately $574,000 in 2017 and $4.2 million in 2016. In January 2018, the Company sold its methane facility for $2.65 million. During 2019, the Company believes its revenues as well as the proceeds received from the sale of the methane facility will be sufficient to fund operating and general and administrative expenses and to remain in compliance with its bank covenants. If revenues and the proceeds from the sale of the methane facility are not sufficient to fund these expenses or if the Company needs additional funds for capital spending, the Company could borrow funds against the credit facility as this facility currently has $2.74 million credit limit base with no funds currently drawn. In addition, if required, the Company could also issue additional shares of stock and/or sell assets as needed to further fund operations.

9. Commitments and Contingencies

The Company as designated operator of the Hoactzin properties was administratively issued an "Incident of Non-Compliance" by the Bureau of Safety and Environmental Enforcement ("BSEE") during the quarter ended September 30, 2012 concerning one of Hoactzin's operated properties. This action called 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. On July 14, 2015, the federal district court in the Eastern District of Louisiana affirmed the civil penalty without reduction. The Company did not further appeal. In the third quarter of 2015, the Company paid the civil penalty and statutory interest thereon from funds borrowed under its credit facility. In the fourth quarter of 2015, the Company received a return of the cash collateral previously provided to RLI Insurance Company. The Company has not advanced any funds to pay any obligations of Hoactzin and no borrowing capability of the Company has been used in connection with its obligations under the Management Agreement, except for those funds used to pay the civil penalty and interest thereon.

During the second quarter of 2015, the Company received from Hoactzin a copy of an internal analysis prepared by Hoactzin setting out certain issues that Hoactzin may consider to form the basis of operational and other claims against the Company primarily under the Management Agreement. This analysis raised issues other than the "Incident of Non-Compliance" discussed above. The Company is discussing this analysis, as well as the civil penalty discussed above, with Hoactzin in an effort to determine whether there is possibility of a reasonable resolution of some or all of these matters on a negotiated basis.

Cost Reduction Measures

Commencing in the quarter ended March 31, 2015 and continuing into the quarter ended June 30, 2018, the Company implemented cost reduction measures including compensation reductions for each employee as well as members of the Board of Directors. These compensation reductions were to remain in place until 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 $70 per barrel. In May 2018, oil prices as so calculated exceeded $70 and compensation reverted 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, a portion which may be paid in stock, to each employee and members of the Board of Directors if is still employed by the Company or still a member of the Board of Directors. For the period January 1, 2015 through December 31, 2018, the reductions were approximately $424,000. Of the $424,000, approximately $95,000 will be paid in the Company's common stock. The $95,000 value represents approximately 100,000 common share valued at $0.95 per share which represents the closing price on December 31, 2018. The Company has not accrued any liabilities associated with these compensation reductions.

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.

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.

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 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, 2018 and December 31, 2017.

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, 2017 and 2018 (in thousands):

Balance December 31, 2016	$	2,046
Accretion expense		141
Liabilities incurred		1
Liabilities settled		(45)
Liabilities sold properties		(11)
Revisions in estimated liabilities		138
Balance December 31, 2017	$	2,270
Accretion expense		141
Liabilities incurred		7
Liabilities settled		(41)
Revisions in estimated liabilities		(198)
Balance December 31, 2018	$	2,179

The revisions in estimated liabilities resulted from change in timing of wells to be plugged, change in inflation factor, and change in current plugging costs.

12. Stock and 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. An 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. On March 21, 2016 at a special meeting of the shareholders, the Plan was amended to permit grant of common stock. 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.

On March 21, 2016, the Company's shareholders approved a 1 for 10 reverse stock split, effective with trading on March 24, 2016. All share and per share information in the following tables has been adjusted to reflect the impact of this reverse stock split.

In August 2018, the Tengasco, Inc. 2018 Stock Incentive Plan (the "2018 Plan") was adopted to continue 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 2018 Plan contains the same substantive terms as the Company's previous stock incentive plan adopted in October, 2000 and thereafter amended until its expiration on January 10, 2018. The 2018 Plan provided an aggregate number of shares for which shares, options, and stock appreciation rights may be issued equal to the number of shares that had been available for issuance in the previous plan upon expiration. The 2018 Plan was approved by a majority of the Company's shareholders acting on written consents and the shares thereunder were subject to Registration Statement on Form S-8 filed August 27, 2018.

The following table summarizes stock option activity in 2018 and 2017:

	2018				2017			
	Shares		Weighted Average Exercise Price		Shares		Weighted Average Exercise Price	
Outstanding, beginning of year	30,000	$	3.73		37,500	$	4.70	
Granted	—	$	—		—	$	—	
Exercised	—	$	—		—	$	—	
Expired/cancelled	(13,125)	$	4.43		(7,500)	$	8.40	
Outstanding, end of year	16,875	$	3.18		30,000	$	3.73	
Exercisable, end of year	16,875	$	3.18		30,000	$	3.73	

The following table summarizes information about stock options outstanding and exercisable at December 31, 2018:

Weighted Average Exercise Price		Options Outstanding (shares)	Weighted Average Remaining Contractual Life (years)	Options Exercisable (shares)
$	4.10	1,875	—	1,875
$	4.80	1,875	0.2	1,875
$	4.40	1,875	0.5	1,875
$	4.40	1,875	0.8	1,875
$	2.50	1,875	1.0	1,875
$	2.30	1,875	1.2	1,875
$	2.70	1,875	1.5	1,875
$	2.20	1,875	1.8	1,875
$	1.20	1,875	2.0	1,875
		16,875		16,875

During 2018 and 2017, the Company issued no additional options to each of the three non-executive directors.

In addition, during 2018, the Company issued 19,366 shares of common stock to the Directors and to the CEO. The shares issued to Directors was in lieu of stock options and vested immediately. The shares issued to the CEO was in lieu of a portion of the quarterly cash payment paid for service as the Company's CEO and vested immediately. The company recorded compensation expense of approximately $23,000 as a result of the stock issuances. In addition, during 2017, the Company issued 23,503 shares of common stock to the Directors and to the CEO. The shares issued to Directors was in lieu of stock options and vested immediately. The shares issued to the CEO was in lieu of a portion of the quarterly cash payment paid for service as the Company's CEO and vested immediately. The company recorded compensation expense of approximately $14,000 as a result of the stock issuances.

13. Income Taxes

The Company did not have taxable income for the years ended December 31, 2018, and 2017.

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, 2018		**Total**
Statutory rate		21%
Tax (benefit) expense at statutory rate	$	326
State income tax (benefit) expense		95
Permanent difference		1
Return to provision		152
Net change in deferred tax asset valuation allowance		(591)
Total income tax provision (benefit)	$	(17)

Year Ended December 31, 2017		**Total**
Statutory rate		34%
Tax (benefit) expense at statutory rate	$	(278)
State income tax (benefit) expense		(42)
Permanent difference		1
Impact of 2017 Tax Act		5,319
Other		14
Net change in deferred tax asset valuation allowance		(5,256)
Total income tax provision (benefit)	$	(242)

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.

At December 31, 2018, federal net operating loss carryforwards amounted to approximately $35.6 million, of which $34.6 million expires between 2019 and 2037 which can offset 100% of taxable income and $1 million that has an indefinite carryforward period which can offset 80% of taxable income per year. The total net deferred tax asset was $130,000 at December 31, 2018 and $242,000 at 2017. In 2018, the Company released a portion of the allowance related to its MTC as a result of the 2017 Tax Act. The Company recorded an allowance on the remaining deferred tax asset at December 31, 2018 primarily due to cumulative losses incurred during the 3 years ended December 31, 2018. The Company recorded a full allowance against the deferred tax asset net of the AMT credit at December 31, 2017 primarily due to cumulative losses incurred during the 3 years ended December 31, 2017. The total valuation allowance December 31, 2018 was $11.5 million, and $12.1 million at December 31, 2017. As the Company adopted ASU 2016-09 during the first quarter of 2017, the excess tax benefits associated with certain stock compensation deductions that have not been previously recognized were recorded to retained earnings net of valuation allowance. The effect on the valuation allowance on this adoption was an increase of $687,000 recorded to retained earnings.

Our open tax years include all returns filed for 2015 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.

Comprehensive tax reform legislation enacted in December 2017, commonly referred to as the Tax Cuts and Jobs Act (the "2017 Tax Act"), made significant changes to U.S. federal income tax laws. The 2017 Tax Act, among other things, reduces the corporate income tax rate to 21%, repeal of the corporate Alternative Minimum tax, partially limits the deductibility of business interest expense and net operating losses, and allows the immediate deduction of certain new investments instead of deductions for depreciation expense over time. The Company had not completed its determination of the accounting implications of the 2017 Tax Act on its tax accruals. However the Company has reasonably estimated the effects of the 2017 Tax Act and recorded provisional amounts in its financial statements as of December 31, 2017. The Company recorded the following provisional amounts for the effects of the 2017 Tax Act.

Beginning January 1, 2018, the U.S. corporate income tax rate was be 21%. The Company was required to recognize the impacts of this rate change on its deferred tax assets and liabilities in the period enacted. The provisional tax effect of the change in tax rate was a decrease to the deferred tax asset of $5.3 million. However, as the Company has a full valuation allowance on its net deferred tax asset, the deferred tax recognized due to the change in rate will be offset with a change in the valuation allowance. Therefore, there was no overall impact to the Financial Statements in 2017 due to this change in rate.

The 2017 Tax Act also repealed the corporate AMT for tax years beginning on or after January 1, 2018 and provides for existing alternative minimum tax credit carryovers to be refunded beginning in 2018. The Company has approximately $260,000 in refundable credits, and it expects that a substantial portion will be refunded between 2018 and 2021. As 50% of the credit will be refunded when we file the 2018 tax return, this amount is recorded as a current accounts receivable on the Balance Sheet at December 31, 2018, with balance of this refund recorded as a non-current accounts receivable.

The ultimate impact of the 2017 Tax Act may differ from the provisional amounts recorded due to additional information becoming available, changes in interpretation of the 2017 Tax Act as well as additional regulatory guidance that may be issued. The company completed its review of the 2017 Tax Act in 2018, and there were no material changes in the measurement period.

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

	Year Ended December 31,	
	2018	**2017**
Net deferred tax assets – current:		
Bad debt	$ —	$ —
Valuation allowance	—	—
Total deferred tax assets – current	$ —	$ —
Net deferred tax assets (liabilities) – noncurrent:		
Net operating loss carryforwards	$ 9,675	$ 8,187
Oil and gas properties	1,327	2,735
Property, Plant and Equipment	(163)	419
Asset retirement obligation	592	616
Tax credits	130	260
Miscellaneous	45	92
Valuation allowance	(11,476)	(12,067)
Total deferred tax assets – noncurrent	$ 130	$ 242
Net deferred tax asset	$ 130	$ 242

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 2018	**1st Qtr**	**2nd Qtr**	**3rd Qtr**	**4th Qtr**
Revenues	$ 1,367	$ 1,475	$ 1,654	$ 1,375
Net income (loss) from continuing operations	133	99	298	(88)
Income (loss) per common share from continuing operations	$ 0.01	$ 0.01	$ 0.03	$ (0.01)

Fiscal Year Ended 2017	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr
Revenues	$ 1,209	$ 1,138	$ 1,035	$ 1,301
Net income (loss) from continuing operations	(170)	(230)	(361)	158
Income (loss) per common share from continuing operations	$ (0.02)	$ (0.02)	$ (0.03)	$ 0.01

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, 2018 and 2017 (in thousands):

	Years Ended December 31,	
	2018	2017
Proved oil and gas properties	$ 6,503	$ 5,704
Unproved properties	23	—
Total proved and unproved oil and gas properties	$ 6,526	$ 5,704
Less accumulated depreciation, depletion and amortization	(1,722)	(984)
Net oil and gas properties	$ 4,804	$ 4,720

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,	
	2018	2017
Property acquisitions proved	$ 164	$ —
Property acquisitions unproved	23	93
Exploration cost	590	69
Development cost	243	—
Total	$ 1,020	$ 162

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,	
	2018	2017
Revenues	$ 5,871	$ 4,683
Production costs and taxes	(3,591)	(3,444)
Depreciation, depletion and amortization	(722)	(796)
Income (loss) from oil and gas producing activities	$ 1,558	$ 443

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, 2016, 2017 and 2018. 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, 2016	**730**	**—**	**730**
Revisions of previous estimates	195	—	195
Improved recovery	—	—	—
Purchase of reserves in place	—	—	—
Extensions and discoveries	47	—	47
Production	(102)	—	(102)
Sales of reserves in place	—	—	—
Proved reserves at December 31, 2017	**870**	**—**	**870**
Revisions of previous estimates	223	—	223
Improved recovery	—	—	—
Purchase of reserves in place	13	—	13
Extensions and discoveries	86	—	86
Production	(98)	—	(98)
Sales of reserves in place	—	—	—
Proved reserves at December 31, 2018	**1,094**	**—**	**1,094**
Proved developed reserves at:			
December 31, 2016	730	—	730
December 31, 2017	832	—	832
December 31, 2018	976	—	976
Proved undeveloped reserves at:			
December 31, 2016	—	—	—
December 31, 2017	38	—	38
December 31, 2018	118	—	118

The Company's Proved Undeveloped Reserves at December 31, 2018 included 7 locations and at December 31, 2017 included 3 locations, and no locations at December 31, 2016 and 2015. During 2016 and 2015, all Proved Undeveloped locations were removed from the Company's Proved Reserves primarily due to the low oil prices experienced during these years. Increases in prices allowed the company to include 3 Proved Undeveloped locations in its December 31, 2017 reserves and 7 Proved Undeveloped locations in its December 31, 2018 reserves. Although the Company completed a well during 2018 that was not included in Proved Reserves at the end of 2017 and therefore contributed to extensions and discoveries, the primary factor causing the revisions as well as the extensions and discoveries during 2018 levels was related to higher oil prices that enabled the Company to consider certain properties as becoming economic or remaining economic longer and to consequently increase the oil volumes included in Proved Reserves.

Tengasco, Inc. and Subsidiaries
Notes to Consolidated Financial Statements

The following table identifies the Company's net proved 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 12/31/2018			Year Ended 12/31/2017			Year Ended 12/31/2016		
	Oil	Gas	Total	Oil	Gas	Total	Oil	Gas	Total
Total proved reserves year-end reserve report	$ 13,976	—	$ 13,976	$ 8,170	—	$ 8,170	$ 5,815	—	$ 5,815
Proved developed producing reserves (PDP)	$ 12,534	—	$ 12,534	$ 7,065	—	$ 7,065	$ 5,397	—	$ 5,397
% of PDP reserves to total proved reserves	90%	—	90%	87%	—	87%	93%	—	93%
Proved developed non-producing reserves	$ 739	—	$ 739	$ 1,082	—	$ 1,082	$ 418	—	$ 418
% of PDNP reserves to total proved reserves	5%	—	5%	13%	—	13%	7%	—	7%
Proved undeveloped reserves (PUD)	$ 703	—	$ 703	$ 23	—	$ 23	$ —	—	$ —
% of PUD reserves to total proved reserves	5%	—	5%	—	—	—	—	—	—

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,		
	2018	2017	2016
Future cash inflows	$ 65,871	$ 39,889	$ 27,253
Future production costs and taxes	(35,877)	(23,343)	(16,270)
Future development costs	(2,833)	(1,586)	(553)
Future income tax expenses	—	—	—
Future net cash flows	27,161	14,960	10,430
Discount at 10% for timing of cash flows	(13,185)	(6,790)	(4,615)
Standardized measure of discounted future net cash flows	$ 13,976	$ 8,170	$ 5,815

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,		
	2018	2017	2016
Balance, beginning of year	$ 8,170	$ 5,815	$ 8,287
Sales, net of production costs and taxes	(2,611)	(1,239)	(2,037)
Discoveries and extensions, net of costs	798	123	35
Purchase of reserves in place	143	—	—
Sale of reserves in place	—	—	(10)
Net changes in prices and production costs	4,304	1,780	(863)
Revisions of quantity estimates	2,180	1,611	(412)
Previously estimated development cost incurred during the year	210	—	—
Changes in future development costs	78	(228)	196
Changes in timing and other	(4)	(164)	(20)
Accretion of discount	708	472	639
Net change in income taxes	—	—	—
Balance, end of year	$ 13,976	$ 8,170	$ 5,815

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, 2018, 2017, and 2016 were $60.21, and $45.83, and $37.35 per barrel of oil, respectively. The Company's proved reserves as of December 31, 2018, 2017 and 2016 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 cost such as general corporate overhead or interest expense.

16. Subsequent Events

On January 2, 2019, 4,962 common shares were issued in the aggregate to the Company's three directors and the CFO and interim CEO. This issuance will result in compensation expense of approximately $4,714 to be recorded during the quarter ended March 31, 2019.

In January 2019, the Company sold its equipment inventory for $150,000. The Company will record a gain on this sale of $45,000 during the quarter ended March 31, 2019.

Exhibit 23.1 Consent of LaRoche Petroleum Consultants, Ltd.

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

We consent to the incorporation by reference in the registration statements on Form S-1, Form S-3 and Form S-8 of Tengasco, Inc. of the references to our name as well as to the references to our third-party report for Tengasco, Inc. which appears in the December 31, 2018 annual report on Form 10-K and/or 10-K/A of Tengasco, Inc.

LAROCHE PETROLEUM CONSULTANTS, LTD.
By LPC, Inc. General Partner

By: /s Stephen W. Daniel
Name: Stephen W. Daniel
Title: Vice President

Richardson, Texas
March 26, 2019

Exhibit 31 Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

CERTIFICATION
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Michael J. Rugen, certify that:

1. I have reviewed this Annual Report on Form 10-K of Tengasco, Inc. for the year ended December 31, 2018.

2. Based on my knowledge, this Annual Report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this Report;

3. Based on my knowledge, the financial statements, and other information included in this Annual Report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this Report;

4. The registrant's certifying officers are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-(f) for the registrant and we have:

(a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this Report is being prepared;

(b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

(c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this Report based on such evaluation; and

(d) disclosed in this Report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an Annual Report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The Registrant's certifying officers have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: March 28, 2019

s/ Michael J. Rugen
Michael J. Rugen
Chief Executive Officer and Chief Financial Officer

Exhibit 32 Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ADOPTED
PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

CERTIFICATION

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 I hereby certify that:

I have reviewed the Annual Report on Form 10-K for the year ended December 31, 2018;

to the best of my knowledge this Annual Report on Form 10-K (i) fully complies with the requirements of section 13(a) or 15(d) of the Securities and Exchange Act of 1934 (15 U.S.C. 78m (a) or 78o (d)); and, (ii) the information contained in this Report fairly present, in all material respects, the financial condition and results of operations of Tengasco, Inc. and its subsidiaries during the period covered by this Report.

Dated: March 28, 2019

s/ Michael J. Rugen
Michael J. Rugen
Chief Executive Officer and Chief Financial Officer

Exhibit 99.1 Report of LaRoche Petroleum Consultants, Ltd.

January 25, 2019

Mr. Michael J. Rugen, CFO
Tengasco, Inc.
6021 S. Syracuse Way, Suite 117
Greenwood Village, CO 80111

Dear Mr. Rugen:

At your request, LaRoche Petroleum Consultants, Ltd. (LPC) has estimated the proved reserves and future cash flow, as of December 31, 2018, to the Tengasco, Inc. (Tengasco) interest in certain properties located in Kansas. The work for this report was completed as of the date of this letter. This report was prepared to provide Tengasco with U.S. Securities and Exchange Commission (SEC) compliant reserve estimates. It is our understanding that the properties evaluated by LPC comprise 100 percent (100%) of Tengasco's proved reserves. We believe the assumptions, data, methods, and procedures used in preparing this report, as set out below, are appropriate for the purpose of this report. This report has been prepared using constant prices and costs and conforms to our understanding of the SEC guidelines, reserves definitions, and applicable financial accounting rules.

Summarized below are LPC's estimates of net reserves and future net cash flow. Future net cash flow is after deducting estimated production and ad valorem taxes, operating expenses, and future capital expenditures but before consideration of federal income taxes. The discounted cash flow values included in this report are intended to represent the time value of money and should not be construed to represent an estimate of fair market value. We estimate the net reserves and future net cash flow to the Tengasco interest, as of December 31, 2018 to be:

	Net Reserves		Future Net Cash Flow ($)	
Category	Oil (barrels)	Gas (Mcf)	Total	Present Worth at 10%
Proved Developed				
Producing	947,612	0	$ 23,859,012	$ 12,533,982
Non-Producing	28,289	0	1,330,805	738,678
Proved Undeveloped	118,122	0	1,971,634	703,235
Total Proved[(1)]	1,094,023	0	$ 27,161,451	$ 13,975,895

(1) The total proved values above may or may not match those values on the total proved summary page that follows this letter due to rounding by the economics program.

The oil reserves include crude oil and condensate. Oil reserves are expressed in barrels, which are equivalent to 42 United States gallons. These properties have never produced commercial volumes of gas.

The estimated reserves and future cash flow shown in this report are for proved developed producing reserves and, for certain properties, proved developed non-producing and proved undeveloped reserves. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

Exhibit 99.1 Report of LaRoche Petroleum Consultants, Ltd.

Estimates of reserves were prepared using standard geological and engineering methods generally accepted by the petroleum industry. The reserves in this report have been estimated using deterministic methods. The method or combination of methods utilized in the evaluation of each reservoir included consideration of the stage of development of the reservoir, quality and completeness of basic data, and production history. Recovery from various reservoirs and leases was estimated after consideration of the type of energy inherent in the reservoirs, the structural positions of the properties, and reservoir and well performance. In some instances, comparisons were made to similar properties where more complete data were available. We have used all methods and procedures that we considered necessary under the circumstances to prepare this report. We have excluded from our consideration all matters to which the controlling interpretation may be legal or accounting rather than engineering or geoscience.

The estimated reserves and future cash flow amounts in this report are related to hydrocarbon prices. Historical prices through December 2018 were used in the preparation of this report as required by SEC guidelines; however, actual future prices may vary significantly from the SEC prices. In addition, future changes in environmental and administrative regulations may significantly affect the ability of Tengasco to produce oil and gas at the projected levels. Therefore, volumes of reserves actually recovered and amounts of cash flow actually received may differ significantly from the estimated quantities presented in this report.

Benchmark prices used in this report are based on the twelve-month, unweighted arithmetic average of the first day of the month price for the period January through December 2018. Oil prices used in this report are referenced to a Cushing West Texas Intermediate crude oil price of $65.56 per barrel and are adjusted for gravity, crude quality, transportation fees, and regional price differentials. This reference price is held constant in accordance with SEC guidelines. The weighted average price after adjustments over the life of the properties is $60.21 per barrel for oil.

Lease and well operating expenses are based on data obtained from Tengasco. Expenses for the properties operated by Tengasco include direct lease and field level costs as well as compression costs, marketing expenses, and allocated overhead costs. Leases and wells operated by others include all direct expenses as well as general and administrative overhead costs allowed under the specific joint operating agreements. Lease and well operating costs are held constant in accordance with SEC guidelines.

Capital costs and timing of all investments have been provided by Tengasco and are included as required for workovers, new development wells, and production equipment. Tengasco has represented to us that they have the ability and intent to implement their capital expenditure program as scheduled. Tengasco's estimates of the cost to plug and abandon the wells net of salvage value are included and scheduled at the end of the economic life of individual properties. These costs are also held constant.

LPC made no investigation of possible volume and value imbalances that may have resulted from overdelivery or underdelivery to the Tengasco interest. Our projections are based on the Tengasco interest receiving its net revenue interest share of estimated future gross oil and gas production.

Exhibit 99.1 Report of LaRoche Petroleum Consultants, Ltd.

Technical information necessary for the preparation of the reserve estimates herein was furnished by Tengasco or was obtained from state regulatory agencies and commercially available data sources. No special tests were obtained to assist in the preparation of this report. For the purpose of this report, the individual well test and production data as reported by the above sources were accepted as represented together with all other factual data presented by Tengasco including the extent and character of the interest evaluated.

An on-site inspection of the properties has not been performed nor has the mechanical operation or condition of the wells and their related facilities been examined by LPC. In addition, the costs associated with the continued operation of uneconomic properties are not reflected in the cash flows.

The evaluation of potential environmental liability from the operation and abandonment of the properties is beyond the scope of this report. In addition, no evaluation was made to determine the degree of operator compliance with current environmental rules, regulations, and reporting requirements. Therefore, no estimate of the potential economic liability, if any, from environmental concerns is included in the projections presented herein.

The reserves included in this report are estimates only and should not be construed as exact quantities. They may or may not be recovered; if recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. These estimates should be accepted with the understanding that future development, production history, changes in regulations, product prices, and operating expenses would probably cause us to make revisions in subsequent evaluations. A portion of these reserves are for behind-pipe zones, undeveloped locations, and producing wells that lack sufficient production history to utilize performance-related reserve estimates. Therefore, these reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogies to similar production. These reserve estimates are subject to a greater degree of uncertainty than those based on substantial production and pressure data. It may be necessary to revise these estimates up or down in the future as additional performance data become available. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geological data; therefore, our conclusions represent informed professional judgments only, not statements of fact.

The results of our third-party study were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Tengasco.

Tengasco makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Tengasco has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3 and Form S-8 of Tengasco of the references to our name, as well as to the references to our third-party report for Tengasco which appears in the December 31, 2018 annual report on Form 10-K and/or 10-K/A of Tengasco. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Tengasco.

We have provided Tengasco with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Tengasco and the original signed report letter, the original signed report letter shall control and supersede the digital version.

Exhibit 99.1 Report of LaRoche Petroleum Consultants, Ltd.

The technical persons responsible for preparing the reserve estimates presented herein 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. The technical person primarily responsible for overseeing the preparation of reserves estimates herein is Stephen W. Daniel. Mr. Daniel is a Professional Engineer licensed in the State of Texas who has 46 years of engineering experience in the oil and gas industry. Mr. Daniel has prepared and overseen preparation of reports for public filings for LPC for the past 16 years. LPC is an independent firm of petroleum engineers, geologists, and geophysicists and are not employed on a contingent basis. Data pertinent to this report are maintained on file in our office.

Very truly yours,

LaRoche Petroleum Consultants, Ltd.
State of Texas Registration Number F-1360
BY LPC, Inc. General Partner

s/ Stephen W. Daniel

Stephen W. Daniel, Vice President
Licensed Professional Engineer
State of Texas No. 58581

SWD:pt
18-908 detail