

TENGASCO INC
Form 10-K
March 31, 2011

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, 2010 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)

Tennessee
(state or other jurisdiction of
Incorporation or organization)

87-0267438
(I.R.S. Employer
Identification No.)

11121 Kingston Pike Suite, E Knoxville, 37934
TN
(Address of Principal Executive Offices) (Zip Code)

Registrant's telephone number, including area code: (865) 675-1554

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

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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 SK is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

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

Large Accelerated Filer Accelerated Filer Non-accelerated Filer Smaller Reporting Company

(Do not check if a Smaller Reporting Company)

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter was approximately \$17 million (June 30, 2010 closing price \$0.45).

The number of shares outstanding of the registrant's \$.001 par value common stock as of the close of business on (March 16th, 2011) was 60,687,413.

Documents Incorporated By Reference

The information required by Part III of the Form 10-K, to the extent not set forth herein, is incorporated herein by reference from the registrant's definitive proxy statement for the Annual Meeting of Shareholders to be held on June 20, 2011, to be filed with the Securities and Exchange Commission pursuant to Regulation 14A not later than 120 days after the close of the registrant's fiscal year.

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FORWARD LOOKING STATEMENTS

The information contained in this Report, in certain instances, includes forward-looking statements within the meaning of applicable securities laws. Forward-looking statements include statements regarding the Company's "expectations," "anticipations," "intentions," "beliefs," or "strategies" or any similar word or phrase regarding the future. Forward-looking statements also include statements regarding revenue margins, expenses, and earnings analysis for 2010 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 for 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 the past year 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.

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 and gas property or a group of properties, expressed in years.

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

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

SWD. Salt water disposal well

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.

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

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

PART I

ITEM 1. BUSINESS.

History of the Company

The Company was initially organized in Utah in 1916 under a name later changed to Onasco Companies, Inc. In 1995, the Company changed its name from Onasco Companies, Inc. by merging into Tengasco, Inc., a Tennessee corporation, formed by the Company solely for this purpose.

OVERVIEW

The Company is in the business of exploration for and production of oil and natural gas. The Company’s primary area of oil exploration and production is in Kansas. The Company’s primary area of gas production is the Swan Creek field in Tennessee.

The Company’s wholly-owned subsidiary, Tengasco Pipeline Corporation (“TPC”) owns and operates a 65-mile intrastate pipeline which it constructed to transport natural gas from the Company’s Swan Creek Field to customers in Kingsport, Tennessee.

The Company’s wholly-owned subsidiary, Manufactured Methane Corporation (“MMC”) owns and operates treatment and delivery facilities using the latest developments in available treatment technologies for the extraction of methane gas from nonconventional sources for delivery through the nation’s existing natural gas pipeline system, including the Company’s pipeline system in Tennessee for eventual sale to natural gas customers.

The Company also has a management agreement with Hoactzin Partners, L.P. (“Hoactzin”) to manage Hoactzin’s oil and gas properties in the Gulf of Mexico offshore Texas and Louisiana (See “4. Management Agreement with Hoactzin”). As consideration for that agreement the Company obtained reimbursement from Hoactzin of a portion of salary and expenses for the Company’s Vice President

Patrick McInturff, as well as an option to participate in production, development, and exploration activities in Hoactzin's properties in those areas. Peter E. Salas, the Chairman of the Board of Directors of the Company, is the controlling person of Hoactzin. He is also the sole shareholder and controlling person of Dolphin Management, Inc., the general partner of Dolphin Offshore Partners, L.P., which is the Company's largest shareholder.

General

1. The Kansas Properties

The Kansas Properties presently include 168 producing oil wells in central Kansas. Our management and staff have a great deal of Kansas exploration and production experience. We have onsite production management and field personnel working in Kansas.

In 2010, the Company continued to focus on both development drilling and to a lesser degree, exploration drilling. Many of the wells that were drilled, were on leases that are still in effect because they are being held by existing production. The leases provide for a landowner royalty of 12.5%. Some wells are subject to an overriding royalty interest from 0.5% to 9%. Other than such wells bearing overriding royalties, the Company maintains a 100% working interest in most of its older wells and any undrilled acreage in Kansas. The terms for most of the Company's newer leases in Kansas are from three to five years.

During 2010, the Company drilled 10 gross wells. The Company has a 100% working interest in 9 of the wells the company directly planned, but had only 17% of one well drilled in a partnership with a local Kansas Company that provided additional information for our use with our Trego county exploration project. The success rate was 5 producers and 4 dry holes for the 9 selected by the Company. The third party well was also dry, but has provided some additional information for use in our offsetting locations.

Kansas as a whole is of major significance to the Company. The majority of the Company's current reserve value, current production, revenue, and future development objectives are centered in the Company's ongoing interest in Kansas. By using 3-D seismic evaluation on existing locations owned by the Company in Kansas, the Company has added and continues to add proven direct offset locations.

A. Kansas Ten Well Drilling Program

On September 17, 2007, the Company entered into a ten well drilling program with Hoactzin, consisting of three wildcat wells and seven developmental wells to be drilled on the Company's Kansas Properties (the "Program"). Under the terms of the Program, Hoactzin paid the Company \$400,000 for each producing well and \$250,000 for each per dry hole. The terms of the Program also provided that Hoactzin would receive all the working interest in the producing wells, and would pay an initial fee to the Company of 25% of its working interest revenues net of operating expenses, referred to as a management fee. The fee paid to the Company by Hoactzin will increase to an 85% working interest when net revenues received by Hoactzin reach an agreed payout point of approximately 1.35 times Hoactzin's purchase price (the "Payout Point").

Nine of the ten wells in the program were completed as oil producers and during the 4th quarter 2010 had gross production of approximately 49 barrels per day in total. Hoactzin paid a total of \$3.85 million (the "Purchase Price") for its interest in the Program resulting in the Payout Point being determined as \$5.2 million. The Purchase Price paid by Hoactzin for its interest in the Program wells exceeded the Company's actual drilling cost of approximately \$2.6 million for the ten wells by more than \$1 million.

In 2010, the wells from the Program produced 20 MBbls of which 13 MBbls were net to Hoactzin. As of December 31, 2010, net revenues received by Hoactzin from the Program totaled \$3.26 million which leaves a balance of \$1.96 million until the Payout Point is reached.

Although production level of the Program wells will decline over time in accordance with expected decline curves, based on the drilling results of the Program wells to date and the current price of oil, the Program wells are now expected to reach the Payout Point by December 31, 2013. However, under the terms of the agreement reaching the Payout Point could be accelerated by applying 75% of the net profits Hoactzin receives from the methane extraction project developed by MMC at the Carter Valley, Tennessee landfill (the "Methane Project"), toward reaching the Payout Point. (The Methane Project is discussed in greater detail below.) The Methane Project net profits if applied would result in the Payout Point being achieved sooner.

As part of a series of transactions with Hoactzin relating to the Program and the Methane Project, on September 17, 2007 the Company entered into another agreement with Hoactzin providing that if the Program and the Methane Project in combination failed to return net revenues to Hoactzin equal to 25% of the Purchase Price by December 31, 2009, then Hoactzin had an option to exchange up to 20% of its net profits interest in the Methane Project for convertible preferred stock to be issued by the Company with a liquidation value equal to 20% of the Purchase Price less the net proceeds received at the time of any exchange. The conversion option would be set at issuance of the preferred stock at the then twenty business day trailing average closing price of Company stock on the NYSE Amex. This option was not available to Hoactzin at year-end 2009 because approximately 50% of the Purchase Price had already been returned to Hoactzin from revenues from the wells in the Program by the end of 2008. Hoactzin has a similar option each year after 2010 in which Hoactzin's then-unrecovered Purchase Price at the beginning of the year is not reduced 20% further by the end of that year, using the same conversion option calculation. The Company, however, may in any year make cash payment from any source in the amount required to prevent such an exchange option for preferred stock from arising. In addition, the conversion right is limited to a conversion of no more than 19% in the aggregate of the outstanding common shares of the Company. In the event Hoactzin's 75% net profits interest in the Methane Project were fully exchanged for preferred stock Hoactzin would retain no net profits interest in the Methane Project after the full exchange.

Under this exchange agreement, if no proceeds at all were received by Hoactzin through 2009 or in a later year (i.e. a worst-case scenario already impossible in view of the success of the Program), then Hoactzin would have an option to exchange 20% of its interest in the Methane Project beginning in 2011 and each year thereafter for preferred stock convertible at the trailing average price before each year's issuance of the preferred. The number of common shares into which the preferred stock could be converted cannot be currently calculated, because the conversion price is based on a future stock price.

However, as stated, net revenues received by Hoactzin from the wells in the Program through December 31, 2010 totaled \$3.26 million leaving a balance of \$0.6 million to reach the point at which no preferred stock can be issued to Hoactzin thus making it highly unlikely that any preferred stock will ever be issued to Hoactzin.

The Company further anticipates that at prices of about \$80.00 per barrel of oil and \$6.00 per Mcf of gas, and at currently expected sales levels of methane gas from the Methane Project that the balance of the unrecovered Purchase Price by Hoactzin may be fully recovered by Hoactzin by year-end 2011. If this occurs, the requirement to issue any preferred ceases to exist. If it does not occur, the Company believes it is highly unlikely that any obligation to issue preferred stock will arise under the terms of this agreement at any time in the future, because the production results in any future year should readily satisfy the small production levels required to prevent an optional preferred stock issuance from arising in any year.

B. Kansas Production

The Company's gross oil production in Kansas increased in 2010 from 2009 levels. In 2010, the Company produced 224 MBbls in Kansas compared to 217 MBbls in 2009. The ten wells that were polymerized in 2010 produced 23 MBbl and the five new wells drilled in 2010 produced approximately 28 MBbl.

The capital projects undertaken by the Company in 2010 were funded from cash flow. The Company plans to be more active in 2011 as oil prices have increased. However, if future oil prices should decrease, it may cause the Company to reduce its anticipated 2011 capital spending. The Company hedged 7,375 barrels of oil from January 2011 through July 2011 to minimize this effect.

2. The Tennessee Properties

In the early 1980's Amoco Production Company owned numerous acres of oil and gas leases in the Eastern Overthrust in the Appalachian Basin, including the area now referred to as the Swan Creek Field. Amoco successfully drilled two natural gas discovery wells in the Swan Creek Field to the Knox Formation. In the mid-1980's, however, development of this field was cost prohibitive due to a substantial decline in worldwide oil and gas prices which was further exacerbated by the high cost of constructing a necessary 23-mile pipeline to deliver gas from the Swan Creek Field to the closest market. In July 1995, the Company acquired the Swan Creek leases and began development of the field.

A. Swan Creek Pipeline Facilities

The Company's completed pipeline system is owned and operated by TPC and extends 65 miles from the Swan Creek Field to a meter station at Eastman Chemical Company's ("Eastman") plant in Kingsport, Tennessee. The pipeline system was built for a total cost of \$16.4 million. At December 31, 2010, the net book value of the pipeline system was approximately \$7.0 million. The net book value at December 31, 2010, includes a writedown of approximately \$5.0 million recorded during 2010 which resulted from the Company's assessment that cash flows generated from the pipeline were insufficient to recover the pipeline's net book value. During the fourth quarter of 2010 the Company received expressions of interest from potential purchasers of the pipeline asset which were significantly below the asset's pre-writedown net book value of \$12 million. These expressions of interest indicated that the carrying amount of the pipeline may not be recoverable.

B. Swan Creek Production and Development

The Company has concluded based on the results of previously drilled wells and seismic data that drilling new gas wells in the Swan Creek Field would not achieve any significant increase in daily gas production totals from the Field. Current wells in production in the Swan Creek Field would be capable of and would likely produce all the remaining reserves in that Field. As a result, the Company has not drilled any new gas wells in the Swan Creek Field since 2004.

Because no drilling for natural gas in the Knox formation in Swan Creek is anticipated in the future, the current production levels less decline are the sole value of natural gas reserves and production. The existing production from the current 15 wells producing natural gas are showing typical Appalachian production declines, which exhibit a long-lived nature but more modest volumes. The experienced decline in actual production levels from existing wells in the Swan Creek Field was expected and predictable. Although there can be no assurance, the Company expects these natural rates of decline in the future will be comparable to historical decline experienced over the 2009-2010 period.

During 2010, the Company had 15 producing gas wells and 6 producing oil wells in the Swan Creek Field. Gas sales from the Swan Creek Field during 2010 averaged 93 Mcfd compared to 124 Mcfd in 2009. Oil sales from the Swan Creek field during 2010 averaged 17 BOPD compared to 16 BOPD in 2009.

The Company continues to evaluate nearby properties for the purpose of exploring the rim of the Swan Creek anticline for Devonian Shale gas production. In 2008, a farmout agreement was signed between the Company and a potential drilling partner on a Company-owned lease in this area. This farmout was unsuccessful and resulted in no assignment of any of the Company's leasehold interest in these properties to any person. The Company may seek development of these properties with other industry partners as it remains possible that when more than one well is drilled, it may be economically feasible to treat (if necessary) the produced gas as required, and to construct gathering facilities necessary to connect to the Company's pipeline to bring the gas to market. To date no industry partners have been found by the Company to further explore these properties and no assurances can be made that such a partner can be found or that an agreement may be reached with such partner on terms acceptable to the Company.

3. Methane Project

On October 24, 2006, the Company signed a twenty-year Landfill Gas Sale and Purchase Agreement (the "Agreement") with BFI Waste Systems of Tennessee, LLC ("BFI"), an affiliate of Allied Waste Industries ("Allied"). In 2008, Allied merged into Republic Services, Inc. ("Republic"). The Company assigned its interest in the Agreement to MMC and provides that MMC will 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 serving the metropolitan area of Kingsport, Tennessee. Republic's facility is located about two miles from the Company's pipeline. The Company installed a proprietary combination of advanced gas treatment technology to extract the methane component of the purchased gas stream. Methane is the principal component of natural gas and makes up about half of the purchased raw gas stream by volume. The Company has constructed a pipeline to

deliver the extracted methane gas to the Company's existing pipeline (the "Methane Project").

The total cost for the Methane Project, including pipeline construction, was approximately \$4.5 million. The costs of the Methane Project were funded primarily by (a) the money received by the Company from Hoactzin to purchase its interest in the Ten Well Program which exceeded the Company's actual costs of drilling the wells in that Program by more than \$1 million; (b) cash flow from the Company's operations; and (c) \$0.8 million of the funds the Company borrowed under its then credit facility with Sovereign Bank of Dallas, Texas ("Sovereign Bank"). Methane gas produced by the project facilities was initially mixed in the Company's pipeline and delivered and sold to Eastman under the terms of the Company's natural gas purchase and sale agreement with Eastman. At current gas production rates in the landfill itself and expected extraction efficiencies, the Company estimates it has the capability to be able to produce and deliver about 400 Mcfd of methane sales gas. The gas supply from this landfill is projected to grow over the years as the underlying operating landfill continues to expand and generate additional naturally produced gas, and for several years following the closing of the landfill, estimated by Republic to occur in 2041. At December 31, 2009 Republic had estimated the landfill closure would occur in 2021. Gas production will continue in commercial quantities up to 10 years after closure of the landfill.

As part of the Methane Project agreement, the Company agreed to install a new force-main water drainage line for Republic, the landfill owner, in the same two-mile pipeline trench as the gas pipeline needed for the Project, reducing overall costs and avoiding environmental effects to private landowners resulting from multiple installations of pipeline. Republic paid the additional material costs for including the water line of approximately \$0.7 million. As a certificated utility, the Company's pipeline subsidiary, TPC, required no additional permits for the gas pipeline construction.

Initial test volumes of methane were produced in late December 2008. During the first two months of 2009, Eastman was reviewing its current air quality permits with regard to MMC's methane production and deliveries did not occur during that review.

MMC declared startup of commercial operations on April 1, 2009. During the month of April, the facility produced and sold 14 MMcf of methane gas to Eastman and was online about 91% of the calendar month. System maintenance and landfill supply adjustments accounted for the remainder of the time. On May 1, 2009, Eastman advised MMC that it was suspending deliveries of the methane gas stream pending approval by the federal Environmental Protection Agency ("EPA") of Eastman's petition for inclusion of treated methane gas as natural gas within the meaning of the EPA's continuous emission monitoring rules applicable to Eastman's large boilers during the annual "smog season" beginning May 1st of each year. Although Eastman had begun seeking this approval in February, 2009, with the assistance of the Air Quality Department of the Tennessee Department of Environment and Conservation, the EPA had not acted by May 1, 2009. Eastman furnished to the EPA information provided by MMC that establishes that the methane gas stream is better fuel under the rule standards than even "natural" gas, which is technically defined in the smog season rules to include gas being "found in geologic formations beneath the earth's surface". Methane sales to Eastman were intended to resume upon EPA's formal approval of Eastman's petition or expansion of the regulatory definition, or both. Because approval was not received, MMC was forced to seek alternative markets for the methane gas stream.

The Company concluded an agreement for sale of the methane gas to Hawkins County Gas Utility, a local utility commencing August 1, 2009 on a month to month basis until either sales to Eastman may resume or other customers were located by the Company.

Effective September 1, 2009 the Company began sales of its Swan Creek gas production to Hawkins County Gas Utility District, because the physical mixing of Swan Creek natural gas with MMC's methane gas caused Eastman to suspend deliveries of both categories of gas as mixed.

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

MMC's plant is capable of producing a daily average of about 400 MMBtu/day of methane from the Carter Valley landfill at the current raw gas volumes being generated underground and collected in Republic's piping and collection system. However, in order to produce 400 MMBtu, the plant needs to remain in operation for a full 24 hours per day. Daily production is less than 400 MMBtu on such days when the plant operates less than a full 24 hours, whether due to any equipment or collection system supply issue. The primary reason experienced for less-than-full-24-hour operation since April 2009 has been frequent spiking in the oxygen content in the raw gas collected by Republic and delivered to the plant, and not to equipment malfunctions in MMC's plant. Oxygen spikes shut down MMC's equipment for safety reasons as high oxygen gas is explosive in our treatment process. In mid-2010 the oxygen spikes increased from occasional spikes to an almost constant level of oxygen that caused longer downtime to our equipment. MMC's plant had minimal production of sales methane during the fourth quarter of 2010 of approximately 5,500 MMBTU of methane gas for an average of 60 MMBTU per day. The MMC plant had no production of sales methane during the third quarter 2010. During the second quarter in 2010, the facility produced approximately 27,000 MMBtu of methane, an average of 300 MMBtu per day. In the first quarter of 2010, the facility had produced about 19,600 MMBtu, an average of 220 MMBtu per day.

Low production in the second half of 2010 was primarily due to the effects of ongoing repairs being made by Republic to its gas collection system to prevent the oxygen intrusion which, as noted above, shuts down MMC's treatment facility to assure safety and reduce risk of explosion. However, water intrusion and weather related issues in July 2010 did cause MMC equipment shutdowns for repair through early August 2010 that also contributed to periods of low production. Those items were remedied by MMC in August 2010 and low production for the period September through December was due to collection system repair issues by Republic, and not MMC's equipment or other factors. Republic continues to make repairs to its collection system, but no assurances can be made concerning when the system repairs will be concluded. Until such time that the repairs are completed, the Company anticipates that only intermittent and minimal volumes will be produced.

On September 17, 2007, Hoactzin, simultaneously with subscribing to participate in the Ten Well Program (the "Program"), pursuant to a separate agreement with the Company was conveyed a 75% net profits interest in the Methane Project. Any net profits from the Methane Project, if received by Hoactzin, would be applied towards the determination of the Payout Point (as defined above) for the Ten Well Program. When the Payout Point is reached from either the revenues from the wells drilled in the Program or the Methane Project or a combination thereof, Hoactzin's net profits interest in the Methane Project will decrease to 7.5%. The agreed method of calculation of net profits takes into account specific costs and expenses as well as gross revenues for the project. As a result of the startup costs and ongoing operating expenses, and reduced production levels discussed above, no net profits as defined have been generated from project startup in April, 2009 through December 31, 2010 for payment to Hoactzin under the net profits interest conveyed. As of the date of this report, all payments applied to reaching the Payout Point have been generated from the Program.

4. Management Agreement with Hoactzin

The Company entered into a Management Agreement with Hoactzin on December 17, 2007. On that same date, the Company entered into an agreement with Charles Patrick McInturff employing him as a Vice-President of the Company. Pursuant to the Management Agreement with Hoactzin, Mr. McInturff's duties while he is employed as Vice-President of the Company will include the management on behalf of Hoactzin 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 consideration for the Company entering into the Management Agreement, Hoactzin agreed that it will reimburse the Company for one-half of Mr. McInturff's salary, as well as certain other benefits he receives during his employment by the Company. In further consideration for the Company's agreement to enter into the Management Agreement, Hoactzin granted to the Company on a dollar for dollar cost basis an option to participate in up to a 15% working interest, in any new drilling or workover activities undertaken on Hoactzin's managed properties during the term of the Management Agreement. During 2009, the Company participated in an unsuccessful workover on West Delta 62 and spent \$0.2 million or 15% of the total workover cost. The Company was able to recoup approximately one third of the cost prior to the well ceasing production. The Company did not participate in any additional projects and does not expect to participate in any future projects. The term of the Management Agreement ends on the earlier of the date Hoactzin conveys its interest in its managed properties or five years (December 2012).

The Company became the operator of certain properties owned by Hoactzin in connection with the Management Agreement. The Company obtained from IndemCo, over time, bonds in the face amount of approximately \$10.7 million for the purpose of covering plugging and abandonment obligations for operated properties located in federal offshore waters in favor of both the Minerals Management Service and certain private parties. In connection with the issuance of these bonds, the Company entered into a Payment and Indemnity Agreement with IndemCo that guarantees payment of any bonding liabilities incurred by IndemCo. Dolphin Direct Equity Partners, LP co-signed the Payment and Indemnity Agreement, thereby becoming jointly and severally liable with the Company for the obligations to IndemCo and also provided \$6.5 million in collateral in the form of cash and a letter of credit to IndemCo. Dolphin Direct Equity Partners is a private equity fund controlled by Peter E. Salas that has a significant economic interest in Hoactzin.

As operator, the Company has routinely contracted in its name for goods and services with vendors in connection with its operation of the Hoactzin properties. In practice, Hoactzin pays directly these invoices for goods and services that are contracted in the Company's name. At December 31, 2009, no vendor payables related to the Management Agreement were recorded by the Company because the amounts were insignificant. During late 2009 and early 2010, Hoactzin undertook several significant operations, for which the Company contracted in the ordinary course. Payables related to these and ongoing operations remained outstanding at the end of 2010 in the amount of \$0.99 million. Because this amount is material, the Company has recorded the Hoactzin-related payables and the corresponding receivable from Hoactzin as of December 31, 2010 in its Consolidated Balance Sheets under "Accounts payable – other" and "Accounts receivable – related party". As a result of the operations performed in late 2009 and early 2010, Hoactzin currently has significant past due balances to several vendors, a portion of which are included on the Company's balance sheet. No Tengasco funds have been advanced by Tengasco to pay any obligations of Hoactzin. No borrowing capability of Tengasco has been or is expected to be used, by the Company in connection with its obligations under the Management Agreement. Hoactzin's obligations to vendors reflected in the account receivable from Hoactzin in the Company's filings have been reduced by Hoactzin from approximately \$1.71 million at March 31, 2010 to \$1.56 million at June 30, 2010 to \$1.24 million at September 30, 2010 to \$0.99 million at December 31, 2010, and the Company expects that Hoactzin will fully satisfy these obligations with its own resources. The Management Agreement terminates at the earlier of the date of sale, if any, by Hoactzin of its managed properties, or December 2012.

5. Other Areas of Development

The Company is continuing to review and analyze potential acquisitions of additional existing oil and gas production in areas of Kansas, Oklahoma, and Texas. Whether the Company will proceed with any such acquisition it deems appropriate will be dependent on a number of factors, including available financing, oil and gas prices, acquisition prices, etc. Future economic conditions, including any sharp decline in oil prices, will have an adverse impact on the Company's ability to acquire additional properties as it will reduce the Company's cash flows and borrowing base. Accordingly, there is no assurance that a suitable property will become available or even if such property becomes available that terms will be established leading to a completion of such a purchase.

The Company has evaluated other geological structures in the East Tennessee area that are similar to the Swan Creek Field. While these areas are of interest, and may be further evaluated at some future time, based on its review to date the Company does not currently intend to actively explore these areas with its own funds. The Company may consider entering into partnerships where further exploration and drilling costs can be largely borne by third parties. There can be no assurances that any third party would participate in a drilling program in these structures, that any of these prospects will be drilled, and if they were drilled that they would result in commercial production.

The Company also intends to establish and explore all business opportunities for connection of the pipeline system owned by the Company's subsidiary TPC to other sources of natural gas or gas produced from non-conventional sources so that revenues from third parties for transportation of gas across the pipeline system may be generated. Although no assurances can be made, such connections may also enable the Company to purchase natural gas from other sources and to then market natural gas to new customers in the Kingsport, Tennessee area at retail rates under a franchise agreement already granted to the Company by the City of Kingsport, subject to approval by the Tennessee Regulatory Authority.

The Company also intends to continue to explore other opportunities such as its Methane Project in Church Hill, Tennessee to obtain natural gas or substitutes for natural gas from non-conventional sources if such gas can be economically treated and tendered in commercial volumes for transportation not only through the Company's existing pipeline system but by other delivery mechanisms and through other interstate or intrastate pipelines or local distribution companies for the purposes of supplementing the Company's revenues from the sale of the methane gas produced by these projects.

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. The principal markets for the Company's natural gas and methane production are local utilities, private industry end-users, and gas marketing companies.

Gas production from the Swan Creek Field can presently be delivered through the Company's completed pipeline to the Powell Valley Utility District in Hancock County, Hawkins County Gas Utility, Eastman and BAE in Sullivan County, other industrial customers in the Kingsport area, as well as gas marketing companies. The Company has acquired all necessary regulatory approvals and necessary property rights for the pipeline system. The Company's pipeline can provide transportation service not only for gas produced from the Company's wells, but also for small independent producers in the local area as well as other pipelines that may be connected to the Company's pipeline in the future.

At present, crude oil produced by the Company in Kansas is sold at or near the wells to Coffeyville Resources Refining and Marketing; LLC ("Coffeyville Refining") in Kansas City, Kansas and to National Cooperative Refinery Association ("NCRA") in McPherson, Kansas. Both Coffeyville Refining and NCRA are solely responsible for transportation to their refineries of the oil they purchase. The Company may sell some or all of its production to one or more additional refineries in order to maximize revenues as purchase prices offered by the refineries fluctuate from time to time. Crude oil produced by the Company in Tennessee is sold to the Ashland Refinery in Kentucky and is transported to the refinery by contracted truck delivery at the Company's expense.

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 companies as available in the Swan Creek Field area and various drilling contractors in Kansas.

Distribution Methods of Products or Services

Crude oil is normally delivered to refineries in Tennessee and Kansas by tank truck and natural gas is distributed and transported by pipeline.

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

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

The Company has numerous competitors in the State of Tennessee that are in the business of exploring for and producing oil and natural gas in Kentucky and East Tennessee areas. 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.

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.

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. They are usually issued within one week of application. The Company generally does not apply for a permit until it is actually ready to commence drilling operations.

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

Sources and Availability of Raw Materials

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

Dependence on One or a Few Major Customers

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

The Company is presently dependent upon a small number of customers for the sale of gas from the Swan Creek Field and the Methane Project. These customers are principally gas marketing companies, utility districts, and industrial customers in the Kingsport area with which the Company may enter into gas sales contracts.

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

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

Need For Governmental Approval of Principal Products or Services

None of the principal products offered by the Company require governmental approval, although permits are required for drilling oil or gas wells. In addition the transportation service offered by TPC is subject to regulation by the Tennessee Regulatory Authority to the extent of certain construction, safety, tariff rates and charges, and nondiscrimination requirements under state law. These requirements are typical of those imposed on regulated common carriers or utilities in the State of Tennessee or in other states. TPC presently has all required tariffs and approvals necessary to transport natural gas to all customers of the Company.

The City of Kingsport, Tennessee has enacted an ordinance granting to TPC a franchise for twenty years (expires June 20, 2020) to construct, maintain and operate a gas system to import, transport, and sell natural gas to the City of Kingsport and its inhabitants, institutions and businesses for domestic, commercial, industrial and institutional uses. This ordinance and the franchise agreement it authorizes also require approval of the Tennessee Regulatory Authority under state law. The Company will not initiate the required approval process for the ordinance and franchise agreement until such time that it can supply gas to the City of Kingsport. Although the Company anticipates that regulatory approval would be granted, there can be no assurances that it would be granted, or that such approval would be granted in a timely manner, or that such approval would not be limited in some manner by the Tennessee Regulatory Authority.

Effect of Existing or Probable Governmental Regulations on Business

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

The State of Tennessee also requires the posting of a bond to ensure that the Company's wells are properly plugged when abandoned. A separate \$2,000 bond is required for each well drilled. The Company currently has the requisite amount of bonds in effect.

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. 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's Board of Directors has adopted resolutions to form an Environmental Response Policy and Emergency Action Response Policy Program. A plan was adopted which provides for the erection of signs at each well and at strategic locations along the pipeline 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 no doubt be enacted and revisions will be made in current laws. No assurance can be given as to that affect 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

The Company presently has 29 full time employees and no part-time employees.

Executive Officers of the Registrant

Identification of Executive Officers

The following table sets forth the names of all current executive officers of the Company. These persons will serve until their successors are elected or appointed and qualified, or their prior resignations or terminations.

| Name | Positions Held | Date of Initial Election of Designation |
|---------------------------|--|---|
| Jeffrey R. Bailey | Chief Executive Officer ¹ | 6/17/2002 |
| Charles Patrick McInturff | Vice-President | 12/18/2007 |
| Cary V. Sorensen | Vice-President; General Counsel; Secretary | 7/09/1999 |
| Michael J. Rugen | Chief Financial Officer | 9/28/2009 |

Business Experience²

Charles Patrick McInturff is 58 years old. Mr. McInturff received a Bachelor of Science Degree in Civil Engineering from Texas A&M University in 1975. He is a Registered Professional Engineer from Texas and a member of the Society of Petroleum Engineers. Before joining the Company he was Vice President of Operations of Capco Offshore, Inc. and related companies in Houston from October 2006 until December 2007 responsible for managing and supervising offshore operations and workovers and identification and evaluation of drilling and workover candidates.

¹ Mr. Bailey is also a director of the Company.

² The background and business experience of Jeffrey R. Bailey is incorporated by reference from the section entitled “Proposal No. 1. Election of Directors” in the Company’s Proxy Statement for the Company’s 2011 Annual Meeting of Stockholders.

From 1991 to 2006, he was employed by Ryder Scott Company in Houston performing reservoir studies including determination of oil, gas, condensate and plant product reserves, enhanced recovery and oil and gas property appraisal. For most of the period from 1978 to 1991, he worked in various petroleum engineering positions at Union Texas Petroleum Corp. in Midland and Houston, Texas, and Karachi, Pakistan and was responsible for surveillance and engineering on primary and secondary recovery projects as well as design and field supervision of workovers, pressure-transient tests and completions both onshore and offshore. During that time period he also worked for Global Natural Resources from 1983 to 1986 as senior operations engineer responsible for all engineering activities. From 1981 to 1983 he was employed by Belco Petroleum performing reservoir engineering duties including field studies, economic evaluation, reserves estimation, and initiating major field studies on waterflood projects in southwestern Wyoming and West Texas. Mr. McInturff was employed by Exxon Co. USA from 1975 to 1978 primarily with the reservoir engineering group in Midland, Texas performing drilling engineering duties including cost estimation, AFE preparation, drilling programs and field supervision. He was responsible for the surveillance of fifteen Permian Basin oil and gas fields in west Texas using both primary and secondary recovery techniques. On December 18, 2007, he was appointed to serve as Vice-President of the Company.

Cary V. Sorensen is 62 years old. He 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.

Michael J. Rugen is 50 years old and was named Chief Financial Officer of the Company in September 2009. He is a certified public accountant (Texas) with over 27 years of experience in exploration and 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.

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., 11121 Kingston Pike, Suite E, Knoxville, TN 37934.

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. 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, the current global recession, and 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, 2010, the outstanding principal amount of the Company's indebtedness to F&M Bank & Trust Company ("F&M Bank") was approximately \$9.5 million. The level of indebtedness, coupled with domestic and global economic conditions, the associated volatility of energy prices, and the levels of disruption and continuing relative illiquidity in the credit markets may, if continued for an extended period, have several important and adverse consequences on the Company's business and operations. For example, any one or more of these factors could (i) make it difficult for the Company to service or refinance its existing indebtedness; (ii) increase the Company's vulnerability to additional adverse changes in economic and industry conditions; (iii) require the Company to dedicate a substantial portion or all of its cash flow from operations and proceeds of any debt or equity issuances or asset sales to pay or provide for its indebtedness; (iv) limit the Company's ability to respond to changes in our businesses and the markets in which we operate; (v) place the Company at a disadvantage to our competitors that are not as highly leveraged; or (vi) limit the Company's ability to borrow money or raise equity to fund our working capital, capital expenditures, acquisitions, debt service requirements, investments, general corporate activity or other financing needs. The Company continues to closely monitor the disruption in the global financial and credit markets, as well as the significant volatility in the market prices for oil and natural gas. As these events unfold, the Company will continue to evaluate and respond to any impact on Company operations. The Company has and will continue to adjust its drilling plans and capital expenditures as necessary. However, external financing in the capital markets may not be readily available, and without adequate capital resources, the Company's drilling and other activities may be limited and the Company's business, financial condition and results of operations may suffer. Additionally, in light of the credit markets and the volatility in pricing for oil and natural gas, the Company's ability to enter into future beneficial relationships with third parties for exploration and production activities may be limited, and as a result, may have an adverse effect on current operational strategy and related business initiatives.

As of September 30, 2009, the Company was out of compliance on the Leverage Ratio and Interest Coverage Ratio covenants under the credit facility. The Company was in compliance with the remaining financial covenants. The noncompliance occurred primarily as a result of the low commodity prices in the last quarter of 2008 and first and second quarters of 2009 that are included in the covenant compliance calculations. The Company received a waiver for noncompliance of these covenants for the quarter ended September 30, 2009. There can be no assurances that the Company will receive a waiver for noncompliance of covenants should future instances occur.

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

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 lenders' practices regarding estimation of reserves.

If either cash flow from operations or the Company's borrowing base decreases for any reason, the Company's ability to undertake exploration and development activities could be adversely affected.

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

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

Borrowings under the Company's credit facility with F&M 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, F&M 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 2008, 2009 and 2010 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. For example, during 2008, the price for oil was extremely volatile. In July 2008, the price of oil which had reached a record high of \$147 per barrel had declined to approximately \$35 per barrel by December 2008. During 2009, oil prices ranged from a low of \$34 per barrel in February 2009 to a high of \$81 per barrel in October 2009. During 2010 oil prices ranged from a low of \$65 per barrel in May 2010 to a high of \$91 per barrel in December 2010. 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, and has an accumulated deficit of \$30.2 million as of December 31, 2010. Although management has substantially reduced its cash operating expenses, these losses have had a material adverse impact on the operations of the Company's business. The Company was profitable in 2006 and 2007. In 2008, the Company had an operating profit before ceiling test write down of \$4.8 million, but due to a non-cash ceiling limitation writedown of \$11.6 million (\$7.7 million net of tax effects), the Company recorded a net income of \$0.2 million. In 2009, the Company also recorded a net loss of \$2.0 million. In 2010, the Company had a profit before pipeline impairment of \$1.3 million, but due to a non-cash pipeline impairment of \$5 million (\$3.0 million net of tax effects) the Company recorded a net loss of \$1.7 million. The Company also recorded a \$0.6 million non-cash unrealized gain on derivatives (\$0.4 million net of tax effects). Net of both the non-cash impairment and the non-cash unrealized gain on derivatives the Company would have recorded an adjusted net income of \$0.9 million. 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 and Tennessee oil and natural gas 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 properties proved reserves will decline materially as production from these properties continues. The Company's future oil and natural gas production is therefore highly dependent upon the level of success in acquiring or finding additional reserves or other alternative sources of production. Any decline in oil prices and any prolonged period of lower prices will adversely impact the Company's future reserves since the Company is less likely to acquire additional producing properties during such periods. The lower oil prices have a chilling effect on new drilling and development as such activities become far less likely to be profitable. Thus, any acquisition of new properties poses a greater risk to the Company's financial conditions as such acquisitions may be commercially unreasonable.

In addition, the Company's drilling for oil and natural gas may involve unprofitable efforts not only from dry wells but also from wells that are productive but do not produce sufficient volumes to be commercially profitable after deducting drilling, operating, and other costs. In addition, 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 reserve estimates or 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 is particularly so if the price of oil declines sharply as it did during the period from mid-2008 through January 2009.

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 or of gas, or both, may be materially revised downward from time to time. As an example, the Company's proved Swan Creek gas reserves calculation has been revised downward in the past as a result of removal of portions of the Company's reported gas reserves from the "proved undeveloped category" ("PUD") and the "proved developed nonproducing" ("PDNP") categories. This downward revision was based on the Company's determination that additional drilling or development of Swan Creek may not occur in the foreseeable future because the economic returns from such drilling or development would not be favorable when compared to the costs and anticipated results of such activity. Although that particular revision at this time will not have a significant impact on overall results of operations in view of the relatively small portion of the Company's current business and assets founded in Swan Creek, other future revisions in oil and gas reserves, may be significant and materially reduce oil or gas reserves.

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. In 2008, the Company did incur a ceiling limitation write-down net of tax effects in the amount of \$7.7 million due to the dramatically lower year-end oil prices in 2008 compared to 2007 and the resulting significant downward adjustment of the Company's estimated proved reserves. The effect of the ceiling writedown resulted in the Company recording net income of \$0.2 million in 2008. The Company did not incur a writedown of its natural gas and crude oil properties in 2009 or 2010.

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

The Company's Pipeline and Methane facility assets are subject to review for impairment whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. The carrying amount is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the pipeline or methane facility assets. Should this occur, the assets carrying amount will be reduced to its fair value and the excess over fair value to net of any tax effects, will be charged to earnings. This expense may not be reversed in future periods. During 2010, the Company incurred a writedown of its pipeline asset net of tax effect in the amount of \$3.0million. This writedown resulted from the Company's assessment that cash flows generated from the pipeline were insufficient to recover the pipeline's net book value. During the fourth quarter of 2010 the Company received expressions of interest from potential purchasers of the pipeline asset which were significantly below the asset's pre-writedown net book value of \$12 million. These expressions of interest indicated that the carrying amount of the pipeline may not be recoverable.

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

At December 31, 2010, 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 of 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 carry forwards may be written down or reversed based on future economic factors that may be experienced by the Company. The effect of such write downs or reversals, if they occur, may be material and substantially adverse.

Shortages of Oil Field Equipment, Services and 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 and as a result the demand for rigs and equipment when oil prices have risen and as a result 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. Higher oil and natural gas prices generally stimulate increased demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services.

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 have to 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 and similar state laws. Under such laws, the Company could be required to remove or remediate wastes or property contamination.

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

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

Insurance Does Not Cover All Risks.

Exploration for and development and production of oil and natural gas and the Company's transportation and other activities can be hazardous, involving unforeseen occurrences such as blowouts, fires and loss of well control, which can result in damage to or destruction of wells or production facilities, injury to persons, loss of life or damage to property or to the environment.

Although the Company maintains insurance against certain losses or liabilities arising from its operations in accordance with customary industry practices and in amounts that management believes to be prudent, insurance is not available to the Company against all operational risks.

The Company's Methane Extraction Operations from Non-conventional Reserves Involve Substantial Cost and are Subject to Various Economic, Operational, and Regulatory Risks.

The Company's operations in projects involving the extraction of methane gas from non-conventional reserves such as landfill gas streams, require investment of substantial capital and are 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 is 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. These projects are also subject to the risk that the products manufactured may not be accepted for transportation in common carrier gas transportation facilities, although the products meet specified requirements for such transportation, or may be accepted on such terms that reduce the returns of such projects to the Company. These projects are also subject to the risk that the product manufactured may not be accepted by purchasers thereof from time to time and the viability of such projects would be dependent upon the Company's ability to locate a replacement market for physical delivery of the gas produced from the project.

The Company's methane extraction business is the subject of a patent granted to the Company. There can be no assurance that our existing patent will not be invalidated, circumvented or challenged, or that patents will be issued for any patents sought in the future, or that the rights granted or to be granted under any patents will provide us competitive advantages.

We have been granted one U.S. patent and have a continuation U.S. patent application pending relating to certain aspects of our methane extraction technology and we may seek additional patents on future innovations. Our ability to license our technology is substantially dependent on the validity and enforcement of this patent. We cannot assure you that our patent will not be invalidated, circumvented or challenged, that patents will be issued for our continuation patent pending, that the rights granted under the patents will provide us competitive advantages, or that our current and future patent applications will be granted. 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 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.

Jeffrey R. Bailey, the Company's Chief Executive Officer, other 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 qualified personnel. The Company does not know whether it would be able to recruit and hire qualified persons upon acceptable terms. The Company does not maintain "Key Person" insurance or retention agreements 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 Amex 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 Owns 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 Management, Inc. the general partner of Dolphin Offshore Partners, L.P. ("Dolphin") which is the Company's largest shareholder. At December 31, 2010, Mr. Salas directly and through Dolphin owned 21,057,492 shares of the Company's common stock and had options granting him the right to acquire an additional 95,000 shares of common stock. His ownership and voting control over approximately 34.7% 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.

As of March 16, 2011 the Company had 60,687,413 shares of common stock outstanding of which 22,546,712 shares were held by affiliates. In addition, options to purchase 1,576,000 shares of unissued common stock were granted under the Tengasco, Inc. Stock Incentive Plan of which options to purchase 880,000 shares were vested at March 17, 2011. On March 17, 2011, the Company issued 100,000 options to directors, which vested immediately.

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

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

The Company may in the future issue previously authorized and unissued securities, resulting in the dilution of the ownership interest of its current stockholders. The Company is currently authorized to issue a total of 100 million shares of common stock with such rights as determined by the Board of Directors. Of that amount, approximately 60 million shares have been issued. The potential issuance of the approximately 40 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 Amex, 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.

General

The Company leases its principal executive offices, consisting of approximately 6,134 square feet located at 11121 Kingston Pike, Suite E, Knoxville, Tennessee at a rental of \$7,284 per month and an office in Hays, Kansas at a rental of \$750.00 per month. The Company has leased office space in Houston, Texas at a rental of approximately \$4,000 per month.

Although the Company does not pay taxes on its Swan Creek leases, it pays ad valorem taxes on its Kansas Properties. The Company has general liability insurance for its Kansas and Tennessee Properties. As of December 31, 2010 the Company does not have a production interest in Texas or Louisiana.

Kansas Properties

The Kansas Properties as of December 31, 2010 contained 178 leases totaling approximately 20,971 gross acres in the vicinity of Hays, Kansas.

The decrease in the total volume of acreage of the Company's Kansas Properties from 22,351 acres at the end of 2009 is primarily due to the Company's evaluation and release of acreage deemed uneconomical. In 2010, the Company continued to focus on retaining properties with geologic value. Many of these leases are still in effect because they are being held by production. These leases provide for a royalty of 12.5%. Some wells are subject to an overriding royalty interest from 0.5% to 9%. The Company maintains a 100% working interest in most of its older wells and any undrilled acreage in Kansas. The terms for most of the Company's newer leases in Kansas are from three to five years.

During 2010, the Company drilled and completed as producers the Albers B#1, Albers A#2, Ververka B#3, Ververka C#2 and the Zerger #2, also drilled 4 dry holes, and participated in drilling an additional dry hole.

Kansas as a whole is of major significance to the Company. The majority of the Company's current reserve value, current production, revenue, and future development objectives are centered in the Company's ongoing interests in Kansas. By using 3-D seismic evaluation on existing locations owned by the Company in Kansas, the Company has added and continues to add proven direct offset locations. Breaking down the Company's assets in Kansas into individual leases produces no apparent stand out leases that appear to be stand-alone principal properties. As a whole, however, our collective central Kansas holdings (see map below) are of major significance and as a group the most materially important segment of the Company as Kansas accounted for 94% of the Company's revenue (i.e. \$12.5 million of \$13.2 million) and 95% of the Company's total oil and gas production during 2010.

The map below indicates the location of the 10 counties in Kansas in which the Company had production as of December 31, 2010.

Tennessee Properties

The Company's Swan Creek leases are on approximately 8,325 gross acres in Hancock and Claiborne Counties in Tennessee. At this time, all of the Company's Tennessee production is from Hancock County.

Reserve and Production Summary

The following tables indicate the county breakdown of 2010 production and reserve values as of December 31, 2010. From a review of the tables below, it is apparent that none of the Company's leases on a standalone basis are significant, but must all be viewed as a whole to appreciate their significance to the company's operations.

Production by Area

| Area | Gross Production MBOE | Average Net Revenue Interest | Percentage of Total Oil Production |
|---------------------|--------------------------|---------------------------------|---------------------------------------|
| Rooks County, KS | 132.6 | 0.749062 | 55% |
| Trego County, KS | 40.8 | 0.773414 | 17% |
| Ellis County, KS | 10.9 | 0.798769 | 4% |
| Graham County, KS | 10.4 | 0.839682 | 4% |
| Russell County, KS | 7.1 | 0.861328 | 3% |
| Barton County, KS | 6.6 | 0.823047 | 3% |
| Pawnee County, KS | 6.2 | 0.705811 | 3% |
| Rush County, KS | 3.8 | 0.853809 | 2% |
| Osborne County, KS | 3.2 | 0.601318 | 1% |
| Stafford County, KS | 2.6 | 0.746911 | 1% |
| Total KS | 224.2 | | 93% |
| Hancock County, TN | 16.1 | 0.690905 | 7% |
| Total | 240.3 | | 100% |

Discounted Reserve Value by Area (in thousands)

| Area | Proved Developed | Proved Undeveloped | Proved Reserves | % of Total |
|---------------------|---------------------|-----------------------|--------------------|---------------|
| Rooks County, KS | \$20,851 | \$7,172 | \$28,023 | 58% |
| Trego County, KS | 6,335 | 1,720 | 8,055 | 17% |
| Ellis County, KS | 1,890 | - | 1,890 | 4% |
| Barton County, KS | 1,452 | 1,657 | 3,109 | 6% |
| Graham County, KS | 2,242 | 667 | 2,909 | 6% |
| Rush County, KS | 762 | - | 762 | 2% |
| Stafford County, KS | 531 | - | 531 | 1% |
| Russell County, KS | 1,071 | - | 1,071 | 2% |
| Pawnee County, KS | 270 | 418 | 688 | 1% |
| Osborne County, KS | 137 | 247 | 384 | 1% |
| Total KS | 35,541 | 11,881 | 47,422 | 98% |
| Hancock County, TN | 922 | - | 922 | 2% |
| Total | \$36,463 | \$11,881 | \$48,344 | 100% |

Reserve Analyses

The Company's estimated total net proved reserves of oil and natural gas as of December 31, 2010 and 2009, and the present values of estimated future net revenues attributable to those reserves as of those dates, are presented in the following tables. All of the Company's reserves were located in the United States. These estimates were prepared by LaRoche Petroleum Consultants, Ltd. ("LaRoche") of Dallas, Texas, and are part of their reserve reports on the Company's oil and gas properties. LaRoche and its employees and its registered petroleum engineers have no interest in the Company and performed those services at their standard rates. LaRoche's estimates were based on a review of geologic, economic, ownership, and engineering data provided to them by the Company. In accordance with SEC regulations, no price or cost escalation or reduction was considered. The technical persons at LaRoche responsible for preparing the Company's reserve estimates meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the standards pertaining to the estimating and auditing of oil and gas reserves information promulgated by the Society of Petroleum Engineers.

Our independent third party engineers do not own an interest in any of our properties and are not employed by the company on a contingent basis.

Total Proved Reserves as of December 31, 2010

| | Producing | Non Producing | Undeveloped | Total |
|--|-----------|---------------|-------------|-----------|
| Natural gas (MMcf) | 27.2 | - | - | 27.2 |
| Oil (MBbls) | 1,554.3 | 245.4 | 696.0 | 2,495.7 |
| Total (MBOE) | 1,558.8 | 245.4 | 696.0 | 2,500.2 |
| Standardized measure of discounted future net cash flow (in thousands) | \$ 28,987 | \$ 7,476 | \$ 11,881 | \$ 48,344 |

Total Proved Reserves as of December 31, 2009

| | Producing | Non-producing | Undeveloped | Total |
|--|-----------|---------------|-------------|----------|
| Natural gas (MMcf) | 115.9 | - | - | 115.9 |
| Oil (MBbl) | 1,340.4 | 238.4 | 694.4 | 2,273.2 |
| Total proved reserves (MBOE) | 1,359.7 | 238.4 | 694.4 | 2,292.5 |
| Standardized measure of discounted future net cash flow (in thousands) | \$15,699 | \$5,185 | \$7,303 | \$28,187 |

Historically, all drilling has primarily been funded by cash flows from operations. During 2010, approximately 127 MBbl of proved undeveloped reserves that existed at December 31, 2009 were converted into proved developed reserves from drilling and completion of the Albers A#2, Albers B#1, Veverka B#3, Veverka C#2, and Zerger #2. All proved undeveloped reserves included in the Company's report at December 31, 2009 related to oil prospects in Kansas. During 2009, no proved undeveloped reserves were converted into proved developed reserves.

The oil and natural gas prices after basis adjustments used in our December 31, 2010 reserve valuation were \$72.30 per Bbl and \$4.89 per Mcf. The oil and natural gas prices after basis adjustments used in our December 31, 2009 reserve valuation were \$53.81 per Bbl and \$4.61 per Mcf. The per Bbl increase in oil price along with identification of additional proved undeveloped locations were the primary factors in the increased 2010 reserve volumes and values as compared to 2009 levels. (Refer to Note 23, Supplemental Oil and Gas Information, Standardized Measure of Discounted Future Net Cash Flows for additional reserve information.)

The prices used in calculating the estimated future net revenue attributable to proved reserves do not reflect market prices for natural gas and oil production sold subsequent to December 31, 2010. There can be no assurance that all of the estimated proved reserves will be produced and sold at the assumed prices. Accordingly, the foregoing prices should not be interpreted as a prediction of future prices.

In substance, the LaRoche Report used estimates of oil and gas reserves based upon standard petroleum engineering methods which include production data, decline curve analysis, volumetric calculations, pressure history, analogy, various correlations and technical factors. Information for this purpose was obtained from owners of interests in the areas involved, state regulatory agencies, commercial services, outside operators and files of LaRoche. The net reserve values in the Report were adjusted to take into account the working interests that have been sold by the Company in various wells.

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 CEO and the Vice President responsible for management of Hoactzin's properties located onshore Texas Gulf Coast and offshore Texas/Louisiana each have extensive professional engineering experience evaluating both domestic and international reserves on a well by well basis and on a company wide basis. On a semi-annual basis, 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 and compares the final report from LaRoche with the Company's in-house reserve calculations and discusses any differences with LaRoche.

Production

The following tables summarize for the past three fiscal years the volumes of oil and gas produced, the Company's operating costs and the Company's average sales prices for its oil and gas. The information includes volumes produced to royalty interest or other parties' working interest.

| Kansas | | | | | |
|--------------------------|------------------|---------------|---------------------------------|---------------------|------------------|
| Years Ended December 31, | Gross Production | | Cost of Production (per BOE) | Average Sales Price | |
| | Oil (MBbl) | Gas (MMcf) | | Oil (Bbl) | Gas (Per Mcf) |
| 2010 | 224.2 | - | \$17.33 | \$72.14 | - |
| 2009 | 216.7 | - | \$14.61 | \$54.48 | - |
| 2008 | 231.6 | - | \$17.21 | \$92.69 | - |

| Tennessee | | | | | |
|--------------------------|------------------|---------------|---------------------------------|---------------------|------------------|
| Years Ended December 31, | Gross Production | | Cost of Production (per BOE) | Average Sales Price | |
| | Oil (MBbl) | Gas (MMcf) | | Oil (Bbl) | Gas (Per Mcf) |
| 2010 | 6.2 | 59.6 | \$32.62 | \$71.05 | \$4.90 |
| 2009 | 5.8 | 78.0 | \$24.60 | \$54.87 | \$3.99 |
| 2008 | 6.4 | 104.0 | \$22.56 | \$88.20 | \$9.10 |

Oil and Gas Drilling Activities

Kansas

In 2010, the Company drilled 5 successful wells, 4 dry holes, and participated in drilling an additional dry hole.

The results of the successful wells drilled in Kansas in 2010 are set out in the following table. The Company has a 100% working interest in each of these successful wells.

| Name of Well | Date Completed | Cumulative Production (Bbl) |
|--------------|----------------|-----------------------------|
| Albers A#2 | November 2010 | 375 |
| Albers B#1 | May 2010 | 20,234 |
| Veverka B#3 | February 2010 | 445 |
| Veverka C#2 | January 2010 | 5,604 |
| Zerger #2 | August 2010 | 898 |