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)

[X} 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, TN (Address of Principal Executive Offices)	37934 (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 [ ] [X] 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 [ ] [X] 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 [X] [ ] No

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

Indicate by check mark if disclosure of delinquent filers in response to Item 405 of Regulation 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 [X]

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter 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 t 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 or the market for or price of the Company's common stock; and control of the Company. All forward-looking statements are based on information available to the Company as of the date hereof, and the Company assumes no obligation to update any such forward-looking statement. The Company's actual results could differ materially from the forward-looking statements. Among the factors that could cause results to differ materially are the factors discussed in "Risk Factors" below in Item 1A of this Report.

Projecting the effects of commodity prices, which in 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.

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Oil. Crude oil, condensate and natural gas liquids.

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

Play. A geographic area with hydrocarbon potential.

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 polymered 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 2011capital 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.