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

REPORT ON FORM 10-K/A

(Amendment No. 1)

(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, 2009** 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	**87-0267438**
(state or other jurisdiction of Incorporation or organization)	(I.R.S. Employer Identification No.)

11121 Kingston Pike Suite, E	Knoxville, TN 37934
(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 [ ] [**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 $21 million (June 30, 2009 closing price $0.56)

The number of shares outstanding of the registrant's $.001 par value common stock as of the close of business on (March 12, 2010) was 59,760,661

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 21, 2010, 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.

10-K/A - EXPLANATORY NOTE

Tengasco, Inc. (“the Company”) filed its Annual Report on Form 10-K for the year ended December 31, 2009 with the Securities and Exchange Commission (“SEC”) on March 31, 2010 (“Original Report”). The Company is filing this Amendment No. 1 on Form 10-K/A to supplement disclosures included in the following items filed in the Original Report:

- Item 2. Properties
  - Reserve Analyses section
- Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations
  - Revenue Recognition section
  - Full Cost Method of Accounting section
- Notes to Consolidated Financial Statements
  - Note 1. Description of Business and Significant Accounting Policies (Revenue Recognition section and Oil and Gas Properties section)
  - Note 23. Supplemental Oil and Gas Information (unaudited) (Estimated Quantities of Oil and Gas Reserves section)

Item 2, Item 7, and Notes 1 and 23 to Consolidated Financial Statements have been replaced in their entirety with the information provided below under the respective headings to include the supplemental disclosures. Aside from the supplemental disclosures, Item 2, Item 7, and Notes 1 and 23 to Consolidated Financial Statements remained unchanged from the Original Report.

This Amendment No. 1 also includes Exhibit 99.1 Report of LaRoche Petroleum Consultants, Ltd. This report had not been included as an exhibit to the Original Report. This Amendment No. 1 also includes a consent from LaRoche Petroleum Consultants, Ltd. in Exhibit 23.1 and new certifications of our Chief Executive Officer and Chief Financial Officer in Exhibit 31.1 and 31.2 and 32.1 and 32.2.

This Amendment No. 1 does not affect the Consolidated Financial Statements included in the Original Report . There are no other changes to the Original Report other than as set forth in this Amendment No. 1. Amendment No. 1 does not reflect events occurring after filing the Original Report or modify those disclosures affected by subsequent events. Accordingly, this Amendment No. 1 should be read in conjunction with the Original Report and other Company filings made with the SEC subsequent to the filing of the Original Report.

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 for use by Patrick McInturff, a Vice President of the Company, 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, 2009 the Company does not have a production interest in Texas and Louisiana.

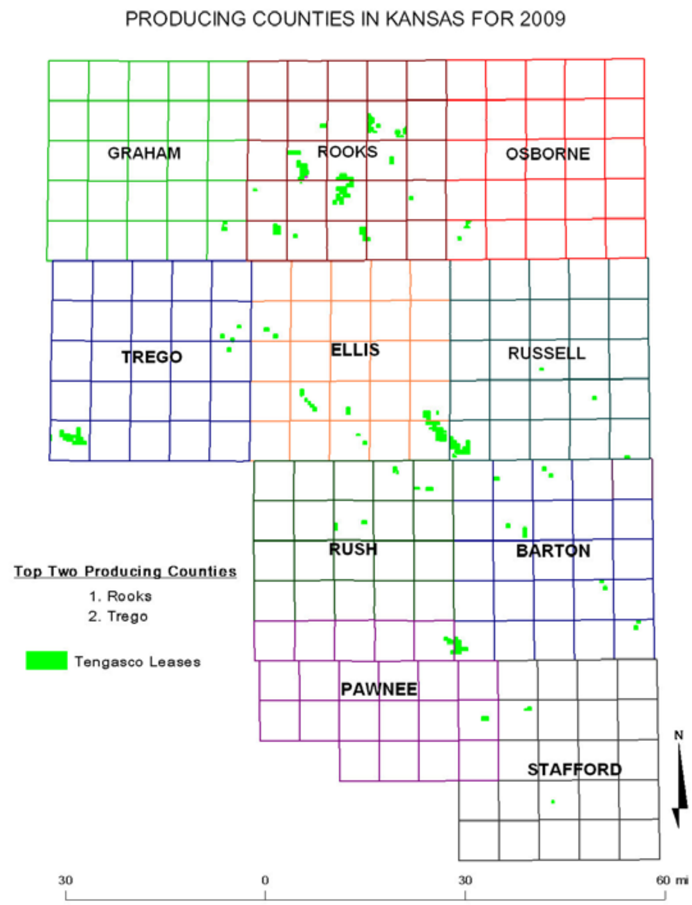
Kansas Properties

The Kansas Properties as of December 31, 2009 contained 150 leases totaling approximately 22,400 gross acres in the vicinity of Hays, Kansas. The decrease in the total volume of acreage of the Company's Kansas Properties from 30,251 acres at the end of 2008 is primarily due to the Company's evaluation and release of acreage deemed uneconomical. In 2009, 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 2009, the Company drilled 1 gross well, the Albers #2 SWD, in which the Company has a 100% working interest. 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 demonstrated by the following facts during the year ending December 31, 2009:

Kansas accounted for 91% of the Company's revenue (i.e. $8.9 million of $9.7 million) and 92% of the Company's total production.

The map below indicates the location of the 10 counties in Kansas in which the Company had production as of December 31, 2009.



Tennessee Properties

The Company's Swan Creek leases are on approximately 8,300 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 2009 production and reserve values as of December 31, 2009. 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	136.8	0.760244	58%
Trego County, KS	28.0	0.820411	12%
Ellis County, KS	12.3	0.820133	5%
Graham County, KS	9.0	0.870513	4%
Russell County, KS	8.1	0.848400	3%
Barton County, KS	7.0	0.814310	3%
Pawnee County, KS	6.0	0.765704	3%
Rush County, KS	4.4	0.845971	2%
Osborne County, KS	2.9	0.626262	1%
Stafford County, KS	2.2	0.827089	1%
Total KS	**216.7**		**92%**
Hancock County, TN	18.7	0.728298	8%
Total	**235.4**		**100%**

Discounted Reserve Value by Area (in thousands)

Area	**Proved Developed**	**Proved Undeveloped**	**Proved Reserves**	**% of Total**
Rooks County, KS	$12,654	$4,220	$16,874	60%
Trego County, KS	1,862	1,780	3,642	13%
Ellis County, KS	1,877	-	1,877	7%
Barton County, KS	822	635	1,457	5%
Graham County, KS	1,076	332	1,408	5%
Rush County, KS	646	-	646	2%
Stafford County, KS	410	123	533	2%
Russell County, KS	418	-	418	2%
Pawnee County, KS	292	118	410	1%
Osborne County, KS	155	95	250	1%
Total KS	**20,212**	**7,303**	**27,515**	**98%**
Hancock County, TN	672	-	672	2%
Total	**$20,884**	**$7,303**	**$28,187**	**100%**

Reserve Analyses

The Company's estimated total net proved reserves of oil and natural gas as of December 31, 2009 and 2008, and the present values of estimated future net revenues attributable to those reserves as of those dates, are presented in 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, 2009

	Producing	**Non Producing**	**Undeveloped**	**Total**
Natural gas (MMcf)	115.9	-	-	115.9
Oil (MBbls)	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

Total Proved Reserves as of December 31, 2008

	Producing	**Non-producing**	**Undeveloped**	**Total**
Natural gas (MMcf)	907.3	2.9	-	910.2
Oil (MBbl)	1,240.0	7.7	-	1,247.7
Total proved reserves (MBOE)	1,391.2	8.2	-	1,399.4
Standardized measure of discounted future net cash flow *(in thousands)*	$10,134	$159	-	$10,293

Historically, all drilling has primarily been funded by cash flows from operations. At price levels used in the December 31, 2008 reserve report, cash flows generated from oil and gas properties as well as availability under the Company's credit facility were insufficient to develop the Company's proved undeveloped prospects within a five year period and therefore the associated proved undeveloped reserves were not included in the Company's report at December 31, 2008. At 2009 price levels, cash flows generated from oil and gas properties were again sufficient to develop the Company's proved undeveloped prospects within a five year period and therefore the associated proved undeveloped reserves were included in the Company's report at December 31, 2009. All proved undeveloped reserves included in the Company's report related to oil prospects in Kansas. During 2008, oil price realization ranged from a high of $127.29 per barrel in June 2008 to a low of $31.69 per barrel in December 2008. Prior to the significant drop in oil prices, approximately 50 MBbl of proved undeveloped reserves from the McElhaney A#1, Veverka B#1, and Veverka B#2 were converted into proved developed reserves. During 2009, no proved undeveloped reserves were converted into proved developed reserves.

In December 2008, the SEC adopted new rules related to "Modernization of Oil and Gas Reporting" which the Company adopted for the year ended December 31, 2009. Per this rule, the Company's proved reserves as of December 31, 2009 are measured by using commodity prices based on the twelve month unweighted arithmetic average of the first day of the month price for the period January through December 2009. The Company's proved reserves as of December 31, 2008 were measured by using prices as of December 31, 2008. Under the SEC's final rule, prior period reserves were not restated. These respective prices are held constant in accordance with SEC guidelines for the life of the wells included in the reserve reports but are adjusted by lease for energy content, quality, transportation, compression and gathering fees, and regional price differentials. 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 oil and natural gas prices after basis adjustments used in our December 31, 2008 reserve valuation were $33.96 per Bbl and $7.76 per Mcf. The $19.85 per Bbl increase in oil price was the primary factor in the increased 2009 reserve volumes and values as compared to 2008 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, 2009. 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 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,	**Production**		**Cost of Production (per BOE)**	**Average Sales Price**	
	Oil (Bbl)	**Gas (Mcf)**		**Oil (Bbl)**	**Gas (Per Mcf)**
2009	217,000	-	$14.61	$54.48	-
2008	231,598	-	$17.21	$92.69	-
2007	178,311	-	$16.97	$66.42	-

Tennessee					
Years Ended December 31,	**Production**		**Cost of Production (per BOE)**	**Average Sales Price**	
	Oil (Bbl)	**Gas (Mcf)**		**Oil (Bbl)**	**Gas (Per Mcf)**
2009	5,750	78,000	$24.60	$54.87	$3.99
2008	6,396	104,043	$22.56	$88.20	$9.10
2007	6,877	117,129	$26.42	$64.81	$6.86

Average sales price for 2008 and 2007 noted in the two tables above have been changed from prior filings to reflect actual average sales prices.

Oil and Gas Drilling Activities

Kansas

In 2009, the Company drilled 1 SWD well in Kansas.

The results of the wells drilled in Kansas in 2009 are set out in the following table. The Company has a 100% working interest in the well.

Name of Well	Date Completed	Cumulative Production (Bbl)
Albers #2	11/2010	n/a- SWD

The Company continues to pursue incremental production increases where possible in the older wells, by using recompletion techniques to enhance production from currently producing intervals.

Tennessee

In 2009 the Company did not drill any new wells in the Swan Creek Field. The Company believes that drilling new gas wells in the Swan Creek Field itself will not contribute to achieving any significant increase in daily gas production totals from the Field. As a result, the Company does not have any plans at the present time to drill any new gas wells in the Swan Creek Field

Gross and Net Wells

The following tables set forth the fiscal years ending December 21, 2007, 2008 and 2009 the number of gross and net development wells drilled by the Company. The term gross wells means the total number of wells in which the Company owns an interest, while the term net wells means the sum of the fractional working interest the Company owns in the gross wells.

	For Years Ending December 31,					
	2009		2008		2007	
Kansas	Gross	Net	Gross	Net	Gross	Net
Productive Wells	-	-	9	7.725	10	4.0
Dry Holes	-	-	3	2.625	6	5.25
Salt Water Disposal	1	1	-	-	-	-

Productive Wells

The following table sets forth information regarding the number of productive wells in which the Company held a working interest as of December 31, 2009. Productive wells are either producing wells or wells capable of commercial production although currently shut-in. One or more completions in the same bore hole are counted as one well.

	Gas		Oil	
	Gross	**Net**	**Gross**	**Net**
Kansas	-	-	213	181
Tennessee	21	16	4	4
Total	21	16	217	185

Developed and Undeveloped Oil and Gas Acreage

As of December 31, 2009 the Company owned working interests in the following developed and undeveloped oil and gas acreage. Net acres refer to the Company's interest less the interest of royalty and other working interest owners.

	Developed		Undeveloped	
	Gross Acres	**Net Acres**	**Gross Acres**	**Net Acres**
Kansas	14,921	12,130	7,450	6,333
Tennessee	3,120	2,370	5,192	4,543
Total	18,041	14,500	12,642	10,876

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

Results of Operations

The Company reported a net loss to holders of common stock of $2.0 million or $0.03 per share in 2009 compared to a net income of $0.2 million or $0.00 per share in 2008 and compared to a net income of $3.5 million or $0.06 per share in 2007.

The Company realized revenues of $9.7 million in 2009 compared to $15.6 million in 2008 and $9.4 million in 2007. Revenues decreased $5.9 million from 2008 primarily due to a decrease in oil prices in Kansas as prices averaged $54.48 in 2009 compared to $92.69 in 2008. The average price received for Kansas oil sales in 2007 was $66.42.

Gas prices received for sales of gas from the Swan Creek Field averaged $3.99 per Mcf in 2009, $9.10 per Mcf in 2008 and $6.86 per Mcf in 2007. Oil prices received for sales of oil from the Swan Creek field averaged $54.87 per barrel in 2009, $80.20 per barrel in 2008 and $64.81 in 2007.

Production costs and taxes in 2009 decreased to $5.3 million from $5.9 million in 2008 and was $4.3 million in 2007.

Depletion, depreciation, and amortization for 2009 was $2.6 million, an increase from $2.2 million in 2008 and $1.6 million in 2007. The increase in 2009 over 2008 levels is primarily due to a $10.7 million increase in future development cost association with the proved reserves, partially offset by a 893 MBOE increase in reserves.

The Company's general and administrative cost was $1.7 million in 2009, $1.9 million in 2008 and 1.4 million in 2007. The 2009, 2008 and 2007 cost included non-cash charges related to stock options of $ 0.2 million, $0.2 million, and $0.1 million respectively.

Professional fees were $0.3 million in 2009 and 2008 and $0.2 million in 2007. This increase in 2008 was due to the Company commencing its review of its internal controls over its financial reporting.

The Company's public relation cost was $50,000 for 2009, compared to $41,000 for 2008 and $22,000 for 2007.

Interest expense was $0.6 million in 2009 and 2008 and $0.3 million in 2007. The increase in interest expense in 2009 and 2008 relates to increased borrowings from the Sovereign credit facility.

During 2009, the Company recorded a noncash unrealized loss on derivatives of $1.3 million or $0.02 per share. This loss was based on the fair value of the oil derivative agreement entered into in July 2009. (See Note 12 Derivatives and Note 13 Fair Value Measurement for additional information related to the derivative transaction and the valuation of this transaction.)

During 2008, the Company recorded an $11.6 million non-cash ceiling test writedown of its oil and gas properties. This writedown resulted from a significant reduction of the Company's proved reserve value as of December 31, 2008 due to low year end oil prices.

The Company recorded a deferred tax asset of $0.2 million in 2009 relating to the Company's net operating loss carry forwards and $5.2 million in 2008 with $1.6 million recognized as income tax expense.

Liquidity and Capital Resources

On June 29, 2006, the Company closed on a $50 million revolving senior credit facility between the Company and Citibank Texas, N.A. ("Citibank"). Under the facility, loans and letters of credit were available to the Company on a revolving basis in an amount outstanding not to exceed the lesser of $50 million or the borrowing base in effect from time to time.

On December 17, 2007, Citibank assigned the Company's revolving credit facility with Citibank to Sovereign Bank as requested by the Company. Under the facility as assigned to Sovereign, loans and letters of credit are available to the Company on a revolving basis in an amount outstanding not to exceed the lesser of $20 million or the Company's borrowing base in effect from time to time. The Sovereign facility is secured by substantially all of the Company's producing and non-producing oil and gas properties and pipeline and the Company's methane assets. The Company's initial borrowing base with Sovereign was set at $7.0 million.

On June 2, 2008, the Company entered into an amendment to its credit facility with Sovereign whereby the Company's borrowing base was increased by the Bank as a result of its review of the Company's currently owned producing properties. The borrowing base was raised to $11 million effective June 2, 2008. The amendment also set the interest rate to the greater of prime plus 0.25% or 6% per annum. The Company had previously utilized about $4.2 million of the facility, leaving approximately $6.8 million available for use by the Company upon this borrowing base increase.

The Company used $5.35 million of the then available $6.8 million for the purchase of the Riffe Field properties in Kansas.

Effective February 5, 2009, the Company amended its credit facility with Sovereign to provide for a monthly reduction of the Bank's commitment by $0.15 million per month for the five month period of February through June 2009. This commitment reduction was not a cash payment obligation of the Company but had the effect of reducing the Company's available borrowing base in monthly increments of $0.15 million under the Sovereign facility.

On July 9, 2009 the Company's borrowing base was increased from $10.25 million to $11.0 million under the revolving senior credit facility between the Company and Sovereign on the completion of the regular semiannual borrowing base review. The $11.0 million borrowing base was again made subject to a monthly available credit reduction of $0.15 million per month beginning August 5, 2009.

As of September 30, 2009, the Company was out of compliance on the Leverage Ratio and Interest Coverage Ratio covenants under the Sovereign credit facility. The Company was in compliance with the remaining financial covenants under the credit facility.

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 has received a waiver from Sovereign Bank for noncompliance of these covenants for the quarter ended September 30, 2009. There can be no assurances that Sovereign Bank will waive noncompliance of covenants should future instances occur.

On February 23, 2010, the Company entered into an amendment to its credit facility with Sovereign increasing the borrowing base from $10.25 million to $11.0 million on completion of the semiannual borrowing base review by Sovereign. The amendment also reduced the monthly commitment reduction from $0.15 million to $0.1 million and changed the maturity date to June 30, 2011. In addition, the amendment modified the covenant compliance calculations. This modification allowed the Company to exclude the first and second quarters of 2009. As of December 31, 2009, the Company was in compliance with all covenants. The next borrowing base review will take place in June 2010.

The total borrowing by the Company under the facility at December 31, 2008 and 2009 was $9.9 million.

Although the Company has not been required as of the date of this Report to make any payment of principal to Sovereign Bank under the borrowing base in effect at any time, the Company can make no assurance that in view of the conditions in the national and world economies, including the realistic possibility of low commodity prices being received for the

Company's oil and gas production for extended periods, that Sovereign may in the future make a redetermination of the Company's borrowing

base to a point below the level of the installment or other payments to Sovereign in such amount and at such times in order to reduce the principal of the Company's outstanding borrowing to a level not in excess of the borrowing base as it may be redetermined.

During 2009 and 2008, the Company remained focused on production and carefully used its cash flow and available credit to do so. However, the Company can make no assurance that it can continue normal operations indefinitely or for any specific period of time in the event of extended periods of low commodity prices, such as occurred in late 2008 and early 2009, or upon the occurrence of any significant downturn or losses in operations. In such event, the Company may be required to reduce costs of operations by various means, including not undertaking certain maintenance or reworking operations that may be necessary to keep some of the Company's properties in production or to seek additional working capital by additional means such as issuance of equity including preferred stock or such other means as may be considered and authorized by the Company's Board of Directors from time to time.

Net cash provided by operating activities was $1.7 million in 2009, $7.1 million in 2008 and $3.4 million in 2007. The reduction of cash provided by operating activities from 2008 to 2009 was primarily due to low product prices received during 2009 as compared to 2008. Cash flow used for working capital was $0.2 million in both 2009 and 2008. Cash provided by working capital was $0.2 million in 2007.

Net cash used in investing activities was $1.5 million in 2009, $14.9 million in 2008, and $3.1 million in 2007. The decrease in 2009 was primarily due to a reduction in investment of $11.0 million in oil and gas properties and $2.5 million in the Methane Project from 2008 levels.

In 2009 no cash was provided by or used in financing activities. Net cash provided by financing activities was $5.8 million in 2008 and $1.6 million in 2007. The decrease in 2009 was due to no new additional borrowings being made by the Company under the Sovereign credit facility.

Critical Accounting Policies

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

Revenue Recognition

Revenues are recognized based on actual volumes of oil and gas sold to purchasers at a fixed or determinable price, when delivery has occurred and title has transferred, and collectability is reasonably assured. Natural gas meters are placed at the customer's location and usage is billed each month. Crude oil is stored and at the time of delivery to the purchasers, revenues are recognized.

Full Cost Method of Accounting

The Company follows the full cost method of accounting for oil and gas property acquisition, exploration and development activities. Under this method, all productive and non-productive costs incurred in connection with the acquisition of, exploration for and development of oil and gas reserves for each cost center are capitalized. Capitalized costs include lease acquisitions, geological and geophysical work, day rate rentals and costs of drilling, completing and equipping oil and gas wells.

Costs, however, associated with production and general corporate activities are expensed in the period incurred. Interest costs related to unproved properties and properties under development are also capitalized to oil and gas properties. Gains or losses are recognized only upon sales or dispositions of significant amounts of oil and gas reserves representing an entire cost center. Proceeds from all other sales or dispositions are treated as reductions to capitalized costs. The capitalized oil and gas property, less accumulated depreciation, depletion and amortization and related deferred income taxes, if any, are generally limited to an amount (the ceiling limitation) equal to the sum of: (a) the present value of estimated future net revenues computed by applying an average price (arithmetic average of the beginning of the month prices for the prior 12 months) to estimated future production of proved oil and gas reserves, less estimated future expenditures (based on current costs) to be incurred in developing and producing the reserves using a discount factor of 10% and assuming continuation of existing economic conditions; and (b) cost of properties not being amortized; and (c) the lower of cost or estimated fair value of unproven properties included in the cost being amortized. Prior to the year ending December 31, 2009, the ceiling limitation was calculated using the year-end price. The change from using the year-end price to using the average price was based on adoption of ASU 2010-03, Extractive Activities – Oil and Gas ("Topic 932");

Oil and Gas Reserve Estimation and Disclosures (see page 48 of the Recent Accounting Pronouncements section).

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

The capitalized costs of oil and gas properties, plus estimated future development costs relating to proved reserves and estimated costs of plugging and abandonment, net of costs relating to proved reserves and estimated costs of plugging and abandonment, net of estimated salvage value, are amortized on the unit-of production method based on total proved reserves. The costs of unproved properties are excluded from amortization until the properties are evaluated, subject to an annual assessment of whether impairment has occurred.

The Company's proved oil and gas reserves as of December 31, 2009 were determined by LaRoche Petroleum Consultants, Ltd. Projecting the effects of commodity prices on production, and timing of development expenditures includes many factors beyond the Company's control. The future estimates of net cash flows from the Company's proved reserves and their present value are based upon various assumptions about future production levels, prices, and costs that may prove to be incorrect over time. Any significant variance from assumptions could result in the actual future net cash flows being materially different from the estimates.

Asset Retirement Obligations

The Company's asset retirement obligations relate to the plugging, dismantling and removal of wells drilled to date. The Company follows the requirements of FASB ASC 410, Asset Retirement Obligations and Environmental Obligations. Among other things, FASB ASC 410 requires entities to record a liability and corresponding increase in long-lived assets for the present value of material obligations associated with the retirement of tangible long-lived assets. Over the passage of time, accretion of the liability is recognized as an operating expense and the capitalized cost is depleted over the estimated useful life of the related asset. The Company's asset retirement obligations relate primarily to the plugging, dismantling and removal of wells drilled to date. The Company's calculation of Asset Retirement Obligation used a credit-adjusted risk free rate of 12%, when the original liability was recognized. In 2009, the retirement obligation for the Albers #2 SWD was recognized using the current credit adjusted risk free rate of 8%. The Company used an estimated useful life of wells ranging from 30-40 years and an estimated plugging and abandonment cost of $5,000 per well. Management continues to periodically evaluate the appropriateness of these assumptions.

Recent Accounting Pronouncements

On February 24, 2010, the FASB issued Accounting Standards Update ("ASU") 2010-09, effective immediately, which amended ASC Topic 855, Subsequent Events. The amendment was made to address concerns about conflicts with SEC guidance and other practice issues. Among the provisions of the amendment, the FASB defined a new type of entity, termed an "SEC filer," which is an entity required to file with or furnish its financial statements to the SEC. Entities other than registrants whose financial statements are included in SEC filings (e.g., businesses or real estate operations acquired or to be acquired, equity method investees, and entities whose securities collateralize registered securities) are not SEC filers. While an SEC filer is still required by U.S. GAAP to evaluate subsequent events through the date its financial statements are issued , it is no longer required to disclose in the financial statements that it has done so or the date through which subsequent events have been evaluated. The Company does not believe the changes have a material impact on our results of operations or financial position.

In January 2010, the FASB issued ASU No. 2010-06, Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements. This update requires more robust disclosures about valuation techniques and inputs to fair value measurement. The update is effective for interim and annual reporting periods beginning after December 15, 2009. This update will have no material effect on the Company's consolidated financial statements.

In July 2009, the FASB issued ASC 855-10-50, Subsequent Events which requires an entity to recognize in the financial statements the effects of all subsequent events that provide additional evidence about conditions that existed at the date of the balance sheet, including the estimates inherent in the process of the financial statements. The final rules were effective for interim and annual periods issued after June 15, 2009. The Company has adopted the policy effective September, 2009. There was no material effect on the Company's consolidated financial statements as a result of the adoption.

In June 2009, the FASB issued ASC 105, Codification which establishes FASB Codification as the source of authoritative generally accepted accounting pronouncements ("U.S. GAAP") recognized by the FASB to be applied by nongovernmental entities. The final rule was effective for interim and annual periods issued after September 15, 2009. The Company has adopted the policy effective September 30, 2009. There was no material effect on the presentation of the Company's consolidated financial statements as a result of the adoption of ASC 105.

On December 31, 2008, the SEC published the final rules and interpretations updating its oil and gas reporting requirements (modernization of Oil and Gas Reporting). In January 2010, the FASB released ASU 2010-03, Extractive Activities- Oil and Gas ("Topic 932); Oil and Gas Reserve Estimation and Disclosures aligning U.S. GAAP standards with the SEC's new rules. Many of the revisions are updates to definitions in the existing oil and gas rules to make them consistent with the petroleum resource management system, which is a widely accepted standard for the management of petroleum resources that was developed by several industry organizations.

Key revisions include: (a) changes to the pricing used to estimate reserves utilizing a 12-month average price rather than a single day spot price which eliminates the ability to utilize subsequent prices to the end of a reporting period when the full cost ceiling was exceeded and subsequent pricing exceeds pricing at the end of a reporting period, (b) the ability to include nontraditional resources in reserves, (c) the use of new technology for determining reserves, and (d) permitting disclosure of probable and possible reserves. The SEC will require companies to comply with the amended disclosure requirements for registration statements filed after January 1, 2010, and for annual reports on Form 10-K for fiscal years ending on or after December 15, 2009. ASU 2010-03 is effective for annual periods ending on or after December 31, 2009. Adoption of Topic 932 did not have a material impact on the Company's results of operations or financial position.

In September 2006, the FASB issued ASC 820, "Fair Value Measurements", which applies under most other accounting pronouncements that require or permit fair value measurements.

FASB ASC 820 provides a common definition of fair value as the price that would be received to sell an asset or paid to transfer a liability in a transaction between market participants. The new standard also provides guidance on the methods used to measure fair value and requires expanded disclosures related to fair value measurements. FASB ASC 820 had originally been effective for financial statements issued for fiscal years beginning after November 15, 2007, however the FASB has agreed on a one year deferral for all non-financial assets and liabilities. The Company adopted FASB ASC 820 effective January 1, 2008. Adoption of this statement did not have a material impact on the Company's financial condition, results of operations, and cash flows.

Contractual Obligations

The following table summarizes the Company's contractual obligations due by period as of December 31, 2009: *(in thousands)*

Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**
Long-Term Debt Obligations (See Note 9 Long Term Debt)	$ 10,181	$ 119	$ 10,062
Operating Lease Obligations (See Note 10 Commitments and Contingencies)	262	58	204
Total	$ 10,443	$ 177	$ 10,266

Notes to Consolidated Financial Statements

Note 1. Description of Business and Significant Accounting Policies

Tengasco, Inc. is a Tennessee corporation ("Tengasco" or the "Company").

The Company is in the business of exploration 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 exploration and 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 nations existing natural gas pipeline system, including the Company's TPC pipeline system in Tennessee for eventual sale to natural gas customers.

Principles of Consolidation

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

Use of Estimates

The accompanying consolidated financial statements are prepared in conformity with U.S. generally accepted accounting principles which require management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The actual results could differ from those estimates.

Revenue Recognition

Revenues are recognized based on actual volumes of oil and gas sold to purchasers at a fixed or determinable price, when delivery has occurred and title has transferred, and collectability is reasonably assured. Natural gas meters are placed at the customer's location and usage is billed each month. Crude oil is stored and at the time of delivery to the purchasers, revenues are recognized.

Cash and Cash Equivalents

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

Inventory

Inventory consists of crude oil in tanks and is carried at lower of cost or market value.

Oil and Gas Properties

The Company follows the full cost method of accounting for oil and gas property acquisition, exploration, and development activities. Under this method, all costs incurred in connection with acquisition, exploration and development of oil and gas reserves are capitalized. Capitalized costs include lease acquisitions, seismic surveys, drilling, completion, and estimated asset retirement costs. The capitalized costs of oil and gas properties, plus estimated future development costs relating to proved reserves and estimated asset retirement costs, which are not already included net of estimated salvage value, are amortized on the unit-of-production method based on total proved reserves. The Company has determined its reserves based upon reserve reports provided by LaRoche Petroleum Consultants Ltd. in 2009, 2008, and 2007. The costs of unproved properties are excluded from amortization until the properties are evaluated, subject to an annual assessment of whether impairment has occurred. The Company currently has $0.1 million in unevaluated properties as of December 31, 2009. Proceeds from the sale of oil and gas properties are accounted for as reductions to capitalized costs unless such sales cause a significant change in the relationship between costs and the estimated value of proved reserves, in which case a gain or loss is recognized.

At the end of each reporting period, the Company performs a “ceiling test” on the value of the net capitalized cost of oil and gas properties. This test compares the net capitalized cost (capitalized cost of oil and gas properties, net of accumulated depreciation, depletion and amortization and related deferred income taxes) to the present value of estimated future net revenues from oil and gas properties using an average price (arithmetic average of the beginning of month prices for the prior 12 months) and current cost discounted at 10% plus cost of properties not being amortized and the lower of cost or estimated fair value of unproven properties included in the cost being amortized (ceiling), Prior to the year ending December 31, 2009, the ceiling was calculated using the year end price. The change from using the year-end price to using the average price was based on adoption of ASU 2010-03, Extractive Activities – Oil and Gas (“Topic 932”); Oil and Gas Reserve Estimation and Disclosures (see page F-15 of the Recent Accounting Pronouncements section).

Asset Retirement Obligation

We record the fair value of a liability for a legal obligation to retire an asset in the period in which the liability is incurred with an offsetting increase to oil and gas properties. For oil and gas properties, this is the period in which the well is drilled or acquired. A legal obligation is a liability that a party is required to settle as a result of an existing law, statute, ordinance or contract. Each period, we accrete the liability to its then present value and depreciate the capitalized cost over the useful life of the related asset.

Pipeline Facilities

The pipeline was placed into service upon its completion on March 8, 2001. The pipeline is being depreciated over its estimated useful life of 30 years beginning at the time it was placed in service.

Manufactured Methane Facilities

The methane facilities were placed into service on April 1, 2009. The methane facilities are being depreciated over an estimated useful life of 13 years and 9 months beginning at the time it was placed in service.

Other Property and Equipment

Other property and equipment is carried at cost. The Company provides for depreciation of other property and equipment using the straight-line method over the estimated useful lives of the assets which range from two to seven years.

Net gains or losses on other property and equipment disposed of are included in operating income in the period in which the transaction occurs.

Stock-Based Compensation

The Company accounts for stock-based compensation in accordance with FASB ASC 718 Compensation-Stock Compensation. ASC 718 requires all share-based payments to employees to be recognized in our consolidated statements of operations based on their estimated fair values. We recognize expense on a straight line basis over the vesting period of the options. The Company recorded compensation expense of $0.2 million in 2009 and 2008 and $0.1 million in 2007.

Accounts Receivable

Senior management reviews accounts receivable on a monthly basis to determine if any receivables will potentially be uncollectible. Based on the information available, the Company believes no allowance for doubtful accounts as of December 31, 2009 and 2008 is necessary. However, actual write-offs may occur.

Income Taxes

The Company accounts for income taxes using the “asset and liability method.” Accordingly, deferred tax liabilities and assets are determined based on the temporary differences between the financial reporting and tax bases of assets and liabilities, using enacted tax rates in effect for the year in which the differences are expected to reverse. Deferred tax assets arise primarily from net operating loss carry-forwards.

Management evaluates the likelihood of realization for such assets at year end providing a valuation allowance for any such amounts not likely to be recovered in future periods. The Company currently has a net operating loss carry forward of $15.5 million.

As of December 31, 2008, the Company also had a deferred tax asset totaling $3.9 million related to a ceiling test write-down of $11.6 million. This deferred tax asset arose from differences between the financial statement carrying value of the Company's oil and gas properties and their respective income tax bases (temporary differences) after taking into consideration the reduced depletion expense from the ceiling test write down. To assess the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of this deferred tax asset will be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. Management has determined that it is more likely than not that all of this deferred tax asset will be realized. The $3.9 million deferred tax asset related to the ceiling test write-down is in addition to the deferred tax assets resulting from the Company's net operating loss carry-forwards. The total deferred tax asset at December 31, 2009 is $9.3 million.

Concentration of Credit Risk

Financial instruments which potentially subject the Company to concentrations of credit risk consist principally of cash and accounts receivable. At December 31, 2009, such cash in banks is in excess of the FDIC insurance limit. The Company's primary business activities include oil and gas sales to a limited number of customers in the states of Kansas and Tennessee. The related trade receivables subject the Company to a concentration of credit risk.

The Company sells a majority of its crude oil primarily to one customer in Tennessee and two customers in Kansas. Additionally, the Company is presently dependent upon a small number of customers for the sale of gas from the Swan Creek Field. Although management believes that customers could be replaced in the ordinary course of business, if the present customers were to discontinue business with the Company, it may have a significant adverse effect on the Company's projected results of operations.

Revenue from the top three purchasers accounted for 85.1%, 10.5% and 3.1% of total oil and gas revenues for year ended December 31, 2009. Revenue from the top three purchasers accounted for 93.6%, 3.5% and 2.5% of total oil and gas revenues for the year ended December 31, 2008. Revenue from the top three purchasers accounted for 91.4%, 4.9% and 3.7% of total oil and gas revenues for the year ended December 31, 2007.

Income per Common Share

In accordance with FASB ASC 260, Earnings Per Share, basic income per share is based on 59,408,990, 59,248,446 and 59,117,176 weighted average shares outstanding for the years ended December 31, 2009, 2008 and 2007, respectively. Diluted earnings per common share are computed by dividing income available to common shareholders by the weighted average number of shares of common stock outstanding during the period increased to include the number of additional shares of common stock that would have been outstanding if the dilutive potential shares of common stock had been issued.

The dilutive effect of outstanding options and warrants is reflected in diluted earnings per share. The numbers of dilutive shares outstanding were 2,244,000 and 1,710,048 for the years ended December 31, 2008 and 2007, respectively. Because the Company had a net loss for the year ended December 31, 2009, dilutive potential shares of common stock are excluded as they are anti-dilutive.

Fair Value of Financial Instruments

Fair value of cash and cash equivalents, investments and short term debt approximate their carrying value due to the short period of time to maturity. Fair value of long term debt is based on quoted market prices or pricing models using current market rates, which approximate carrying value. (See Note 12 Fair Value Measurement)

Derivative Financial Instruments

The Company uses derivative instruments to manage our exposure to commodity price risk on sales of oil production. We do not enter into the derivative instruments for speculative trading purposes. We present the fair value of our derivative contracts on a net basis where the right to offset is provided for in our counterparty agreements. (See Note 13 Derivatives)

Reclassifications

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

Note 23. Supplemental Oil and Gas Information (unaudited)

Information with respect to the Company's oil and gas producing activities is presented in the following tables. Estimates of reserves quantities, as well as future production and discounted cash flows

before income taxes, were determined by LaRoche Petroleum Consultants Ltd. All of the Company's reserves were located in the United States.

Capitalized Costs Related to Oil and Gas Producing Activities

The table below reflects our capitalized costs related to our oil and gas producing activities at December 31, 2009 and 2008 (in thousands):

	Years Ended December 31,	
	2009	**2008**
Proved oil and gas properties	$ 24,182	$ 23,031
Unproved properties	109	1,243
Total proved and unproved oil and gas properties	$ 24,291	$ 24,274
Less accumulate depreciation, depletion and amortization	11,931	10,132
Net oil and gas properties	$ 12,360	$ 14,142

Oil and Gas Related Costs

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

	Years Ended December 31,				
	2009		**2008**		**2007**
Property acquisitions proved	$ -		$ 5,350		$ 200
Property acquisitions unproved	-		-		-
Exploration cost	-		-		-
Development cost	1,020		6,614		4,991
Total	$ 1,020		$ 11,964		$ 5,191

Results of Operations from Oil and Gas Producing Activities

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

	Year Ended December 31,				
	2009		**2008**		**2007**
Revenues	$ 9,711		$15,570		$ 9,300
Production costs and taxes	(5,225)		(5,731)		(4,160)
Depreciation, depletion and amortization	(1,800)		(1,374)		(835)
Income from oil and gas producing activities	$ 2,686		$ 8,465		$ 4,305

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

Estimated Quantities of Oil and Gas Reserves

The following table sets forth the Company’s net proved oil and gas reserves and the changes in net proved oil and gas reserves for the years ended December 31, 2009, 2008 and 2007.

	Oil (MBbls)	**Gas (MMcf)**	**MBOE**
Proved reserves at December 31, 2006	**1,712**	**1,307**	**1,930**
Revisions of previous estimates **(1)**	700	(46)	692
Improved recovery	19	-	19
Purchase of reserves in place	16	-	16
Extensions and discoveries	14	-	14
Production	(185)	(127)	(206)
Sales of reserves in place	-	-	-
Proved reserves at December 31, 2007	**2,276**	**1,134**	**2,465**
Revisions of previous estimates **(2)**	(1,313)	(120)	(1,333)
Improved recovery	59	-	59
Purchase of reserves in place	234	-	234
Extensions and discoveries	154	-	154
Production	(162)	(104)	(180)
Sales of reserves in place	-	-	
Proved reserves at December 31, 2008	**1,248**	**910**	**1,399**
Revisions of previous estimates **(3)**	1,203	(721)	1,084
Improved recovery	-	-	-
Purchase of reserves in place	-	-	-
Extensions and discoveries	-	-	-
Production	(171)	(73)	(183)

Sales of reserves in place	(7)	--	(7)
Proved reserves at December 31, 2009	**2,273**	**116**	**2,293**
Proved developed reserves at:			
December 31, 2007	1,605	1,131	1,793
December 31, 2008	1,240	907	1,391
December 31, 2009	1,579	116	1,598
Proved undeveloped reserves at:			
December 31, 2007	664	-	664
December 31, 2008	-	-	-
December 31, 2009	694	-	694

1. The 700 MBbl upward revision in oil reserves was primarily due to higher oil prices used at December 31, 2007 compared to prices used at December 31, 2006. The higher prices used caused the upward revision for two reasons. First, the higher prices used allowed the inclusion of the estimates of some wells that at lower prices were uneconomic to be produced. Second, the higher oil prices used postponed the date all wells would eventually be shut down as unprofitable and thus extended the economic life of all wells for the purpose of the calculations of estimates. Therefore, both the increased number of economically producible wells, and the incremental volumes resulting from a longer economic production period are included in the reserve report.

2. The proved undeveloped reserve volumes decreased 664 MBbl. At 2008 price levels, cash flows generated from oil and gas properties as well as availability under the Company's credit facility were insufficient to develop the Company's proved undeveloped prospects that existed at December 31, 2008 within a five year period and therefore the associated proved undeveloped reserves were required to be and were dropped for our report. The remaining 649 MBbl downward revision in oil reserves was primarily due to lower oil prices used at December 31, 2008 compared to prices used at December 31, 2007. The lower oil prices decreased the economic life of Company wells. In addition, certain wells that were economic at higher prices would not be able to be produced economically at decreased price levels. Therefore, the decremental volumes resulting from a shorter economic production period as well as the decreased number of economically producible wells were excluded from the reserve report.

3. The proved undeveloped reserve volumes increased 694 MBbl. At 2009 price levels, cash flows generated from oil and gas properties were sufficient to develop the Company's proved undeveloped prospects within a five year period and therefore the associated proved undeveloped reserves were included in our report at December 31, 2009. The remaining 509 MBbl upward revision in oil reserves were primarily due to higher oil prices used at December 31, 2009 compared to prices used at December 31, 2008.

The higher oil prices extended the economic life of certain Company wells. In addition, certain wells that were uneconomic at lower prices were able to be produced economically at increased price levels. Therefore, the incremental volumes resulting from a longer production period as well as the increased number of economically producible wells were included in the reserve report. The 721 MMcf downward revision in gas reserves was primarily due to lower gas prices used at December 31, 2009 compared to prices used at December 31, 2008. The lower gas prices decreased the economic life of certain Company wells. In addition, certain wells that were economic at higher prices were not able to be produced economically at decreased price levels. Therefore, the decremental volumes resulting from a shorter production period as well as the decreased number of economically producible wells were excluded from the reserve report.

(amounts in thousands)	**Year Ended 12/31/09**				**Year Ended 12/31/08**				**Year Ended 12/31/07**		
	Oil	**Gas**	**Total**		**Oil**	**Gas**	**Total**		**Oil**	**Gas**	**Total**
Total proved reserves year-end reserve report	$27,964	223	$28,187		$9,177	1,116	$10,293		$52,117	1,510	$53,627
Proved developed producing reserves (PDP)	$15,476	223	$15,699		$9,020	1,114	$10,134		$36,319	1,485	$37,804
% of PDP reserves to total proved reserves	55%	1%	56%		87%	11%	98%		67%	3%	70%
Proved developed non-producing reserves	$5,185	-	$5,185		$157	2	$159		$441	25	$466
% of PDNP reserves to total proved reserves	18%	-	18%		2%	-	2%		1%	-	1%
Proved undeveloped reserves (PUD)	$7,303	-	$7,303		-	-	-		$15,357	-	$15,357
% of PUD reserves to total proved reserves	26%	-	26%		-	-	-		29%	-	29%

Standardized Measure of Discounted Future Net Cash Flows

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

		December 31,				
		2009		**2008**		**2007**
Future cash inflows		$ 122,844		$ 51,388		$ 206,276
Future production costs and taxes		(56,550)		(36,491)		(76,944)
Future development costs		(11,039)		(309)		(10,175)
Future income tax expenses		-		-		-

Net future cash flows	55,255	14,588	119,157
Discount at 10% for timing of cash flows	(27,068)	(4,295)	(65,530)
Discounted future net cash flows from proved reserves	$ 28,187	$ 10,293	$ 53,627

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

	December 31,		
	2009	**2008**	**2007**
Balance, beginning of year	$10,293	$53,627	$26,469
Sales, net of production costs and taxes	(4,486)	(9,839)	(5,140)
Discoveries and extensions, net of costs	-	1,492	1,166
Purchase of reserves in place	-	1,642	568
Sale of reserves in place	(109)	-	-
Net changes in prices and production costs	10,433	(30,890)	16,893
Revisions of quantity estimates	17,705	(9,373)	16,584
Accretion of discount	1,029	1,029	2,647
Net change in income taxes	-	-	-
Previously estimated development cost incurred during the year	28	-	-
Changes in future development costs	(5,489)	3,251	(5,669)
Changes in production rates and other	(1,217)	(646)	109
Balance, end of year	$28,187	$10,293	$53,627

Estimated future net cash flows represent an estimate of future net revenues from the production of proved reserves using current sales prices, along with estimates of the operating costs, production taxes and future development and abandonment cost (less salvage value) necessary to produce such reserves. The prices used for December 31, 2009, 2008 and 2007 were $53.81, $33.96, and $85.44, per barrel of oil and $4.61, $7.76, and $7.21 per MCF of gas, respectively. The Company's proved reserves as of December 31, 2009 were measured by using commodity prices based on the twelve month unweighted arithmetic average of the first day of the month price for the period January through December 2009. The Company's proved reserves as of December 31, 2008 and 2007 were measured by using end of year prices. No deduction has been made for depreciation, depletion or any indirect costs such as general corporate overhead or interest expense.

Item 15

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

Exhibit Index

Exhibit Number	Description
3.1	Charter (Incorporated by reference to Exhibit 3.7 to the registrant's registration statement on Form 10-SB filed August 7, 1997 (the "Form 10-SB"))
3.2	Articles of Merger and Plan of Merger (taking into account the formation of the Tennessee wholly-owned subsidiary for the purpose of changing the Company's domicile and effecting reverse split) (Incorporated by reference to Exhibit 3.8 to the Form 10-SB)
3.3	Articles of Amendment to the Charter dated June 24, 1998 (Incorporated by reference to Exhibit 3.9 to the registrant's annual report on Form 10-KSB filed April 15, 1999 (the "1998 Form 10-KSB"))
3.4	Articles of Amendment to the Charter dated October 30, 1998 (Incorporated by reference to Exhibit 3.10 to the 1998 Form 10-KSB)
3.5	Articles of Amendment to the Charter filed March 17, 2000 (Incorporated by reference to Exhibit 3.11 to the registrant's annual report on Form 10-KSB filed April 14, 2000 (the "1999 Form 10-KSB"))
3.6	By-laws (Incorporated by reference to Exhibit 3.2 to the Form 10-SB)
3.7	Amendment and Restated By-laws dated May 19, 2005 (Incorporated by reference to the registrant's annual report on Form 10-K for the year ended December 31, 2005)
4.1	Form of Rights Certificate Incorporated by reference to registrant's statement on Form S-1 filed February 13, 2004 Registration File No. 333-109784 (the "Form S-1")
10.1	Natural Gas Sales Agreement dated November 18, 1999 between Tengasco, Inc. and Eastman Chemical Company (Incorporated by reference to Exhibit 10.10 to the registrant's current report on Form 8-K filed November 23, 1999)

10.2	Amendment Agreement between Eastman Chemical Company and Tengasco, Inc. dated March 27, 2000 (Incorporated by reference to Exhibit 10.14 to the registrant's 1999 Form 10-KSB)
10.3	Tengasco, Inc. Incentive Stock Plan (Incorporated by reference to Exhibit 4.1 to the registrant's registration statement on Form S-8 filed October 26, 2000)
10.4	Amendment to the Tengasco, Inc. Stock Incentive Plan dated May 19, 2005 (Incorporated by reference to Exhibit 4.2 to the registrant's registration statement on Form S-8 filed June 3, 2005)
10.5	Loan and Security Agreement dated as of June 29, 2006 between Tengasco, Inc. and Citibank Texas, N.A. (Incorporated by reference to Exhibit 10.1 to the registrant's current report on Form 8-K dated June 29, 2006)
10.6	Subscription Agreement of Hoactzin Partners, L.P. for the Company's ten well drilling program on its Kansas Properties dated August 3, 2007 (Incorporated by reference to Exhibit 10.15 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2007 filed March 31, 2008 [the "2007 Form 10-K"])..
10.7	Agreement and Conveyance of Net Profits Interest dated September 17, 2007 between Manufactured Methane Corporation as Grantor and Hoactzin Partners, LP as Grantee (Incorporated by reference to Exhibit 10.16 to the 2007 Form 10-K).
10.8	Agreement for Conditional Option for Exchange of Net Profits Interest for Convertible Preferred Stock dated September 17, 2007 between Tengasco, Inc., as Grantor and Hoactzin Partners, L.P., as Grantee (Incorporated by reference to Exhibit 10.17 to the 2007 Form 10-K).
10.9	Assignment of Notes and Liens Dated December 17, 2007 between Citibank, N.A., as Assignor, Sovereign Bank, as Assignee and Tengasco, Inc., Tengasco Land & Mineral Corporation and Tengasco Pipeline Corporation as Debtors (Incorporated by reference to Exhibit 10.18 to the 2007 Form 10-K).
10.10	Management Agreement dated December 18, 2007 between Tengasco, Inc. and Hoactzin Partners, L.P. (Incorporated by reference to Exhibit 10.20 to the 2007 Form 10-K).
10.11	Amendment to the Tengasco, Inc. Stock Incentive Plan dated February 1, 2008, 2008 (Incorporated by reference to Exhibit 4.1 to the registrant's registration statement on Form S-8 filed June 3, 2008)
10.12	Assignment of Leases from Black Diamond Oil, Inc. to Tengasco, Inc. (Incorporated by reference to Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2008 filed on August 11, 2008).

10.13	Energy Option Transaction Confirmation Agreement (Put) between Tengasco, Inc. and Macquarie Bank Limited dated September 17, 2009.
10.14	Energy Option Transaction Confirmation Agreement (Call) Amendment between Tengasco, Inc. and Macquarie Bank Limited dated September 17, 2009.
14	Code of Ethics (Incorporated by reference to Exhibit 14 to the registrant's annual report on Form 10-K filed March 30, 2004)
21	List of subsidiaries (Incorporated by reference to Exhibit 21 to the 2007 Form 10-K).
23.1*	Consent of LaRoche Petroleum Consultants, Ltd.
23.2	Consent of Risked Revenue Energy Associates
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a)/15d-14(a)
32.1*	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1*	Report of La Roche Petroleum Consultants, Ltd.

* Exhibit filed with this Report

Signatures

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

Dated: January 24, 2011

Tengasco, Inc.

(Registrant)

By: s/ Jeffrey R. Bailey
Jeffrey R. Bailey,
Chief Executive Officer

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