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

REPORT ON FORM 10-K/A

(Amendment No. 2)

(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 (state or other jurisdiction of Incorporation or organization)	**87-0267438** (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”) and also filed its Form 10-K/A (“Amendment No. 1”) on January 24, 2011. The Company is filing this Amendment No. 2 on Form 10-K/A for the sole purpose of including Item 8 Financial Statements and Supplementary Data in its entirety. Other than including Item 8 in its entirety, no further amendments of any kind is being made by this Amendment No. 2. Amendment No. 1 did not include Item 8 in its entirety, but included text only related to the specific following Notes to Consolidated Financial Statements in Item 8 in which disclosure language had been supplemented:

- 1. Description of Business and Significant Accounting Policies (Revenue Recognition section)
- 1. Description of Business and Significant Accounting Policies (Oil and Gas Properties section)
- 23. Supplemental Oil and Gas Information (unaudited) (Estimated Quantities of Oil and Gas Reserves section)

This Amendment No. 2 also includes certifications of our Chief Executive Officer and Chief Financial Officer in Exhibit 31.1 and 31.2 and 32.1 and 32.2. Since Amendment No. 1 had previously included Item 2 Properties and Item 7 Management’s Discussion and Analysis of Financial Condition and Results of Operations in their entirety, the text associated with Item 2 and Item 7 are not included in this Amendment No. 2.

This Amendment No. 2 does not affect the Consolidated Financial Statements included in the Original Report or any disclosures. Amendment No. 2 does not reflect events occurring after filing the Original Report or modify those disclosures affected by subsequent events. Accordingly, this Amendment No. 2 should be read in conjunction with the Original Report, Amendment No. 1, and other Company filings made with the SEC subsequent to the filing of the Original Report.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

ITEM 15. EXHIBITS AND FINANCIAL STATEMENTS SCHEDULES

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

1. Financial Statements:

   Consolidated Balance Sheets

   Consolidated Income Statements

   Consolidated Statements of Stockholders Equity

   Consolidated Statements of Cash Flows

   Notes to Consolidated Financial Statements

2. Financial Schedules:

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

3. Exhibits.

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

Exhibit Index

Exhibit Number	Description
3.1	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 28, 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

Tengasco, Inc.
and Subsidiaries

Consolidated Financial Statements
Years Ended December 31, 2009, 2008, and 2007

Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying consolidated balance sheets of Tengasco, Inc. (the "Company") as of December 31, 2009 and 2008, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the years in the three-year period ended December 31, 2009. The Company's management is responsible for these consolidated financial statements. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The company was not required for 2009 to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Tengasco, Inc. as of December 31, 2009 and 2008, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2009 in conformity with accounting principles generally accepted in the United States of America.

/s/ Rodefer Moss & Co, PLLC
Certified Public Accountants
Knoxville, Tennessee
March 26, 2010

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

	December 31, 2009	December 31, 2008
Assets		
Current		
Cash and cash equivalents	$ 422	$ 245
Accounts receivable	1,130	1,104
Participant receivables	18	24
Inventory	581	476
Other current assets	20	10
Total current assets	2,171	1,859
Restricted cash	121	121
Loan fees	146	202
Oil and gas properties, net (*full cost accounting method*)	12,360	14,142
Pipeline facilities, net	12,397	12,380
Methane project, net	4,403	4,357
Other property and equipment, net	306	285
Deferred tax asset	9,270	9,101
Total assets	$ 41,174	$ 42,447

See accompanying Notes to Consolidated Financial Statements

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

	December 31, 2009	December 31, 2008
Liabilities and Stockholders' Equity		
Current liabilities		
Current maturities of long-term debt	$ 119	$ 75
Accounts payable	742	701
Accrued liabilities	302	437
Unrealized derivative liability	748	-
Total current liabilities	1,911	1,213
Asset retirement obligation	450	656
Deferred conveyance oil and gas properties	490	1,097
Prepaid revenues	853	853
Long term debt, less current maturities	10,062	10,052
Unrealized derivative liability	565	-
Total liabilities	14,331	13,871
Stockholders' equity		
Common stock, $.001 par value: authorized 100,000,000 Shares; 59,760,661 and 59,350,661 shares issued and outstanding	60	59
Additional paid in capital	55,277	54,993
Accumulated deficit	(28,494)	(26,476)
Total stockholders' equity	26,843	28,576
Total liabilities and stockholders' equity	$41,174	$ 42,447

See accompanying Notes to Consolidated Financial Statements

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

	Years ended December 31, 2009	2008	2007
Revenues and other income			
Oil and gas revenues	$ 9,711	$ 15,570	$ 9,300
Pipeline transportation revenues	19	12	51
Interest income	1	19	17
Total revenues and other income	9,731	15,601	9,368
Cost and expenses			
Production costs and taxes	5,315	5,888	4,323
Depreciation, depletion, and amortization	2,571	2,160	1,631
Ceiling test impairment	-	11,608	-
General and administrative	1,731	1,863	1,417
Professional fees	304	264	232
Public relations	50	41	22
Total cost and expenses	9,971	21,824	7,625
Net income (loss) from operations	(240)	(6,223)	1,743
Other expense			
Interest expense	634	608	333
Unrealized loss on derivatives	1,313	-	-
Total other expense	1,947	608	333
Deferred tax benefit	169	8,625	2,100
Income tax expense	-	(1,624)	-
Net income (loss)	$ (2,018)	$ 170	$ 3,510
Net income (loss) per share			
Basic	$ (0.03)	$ 0.00	$ 0.06
Fully diluted	$ (0.03)	$ 0.00	$ 0.06
Shares used in computing earnings per share			
Basic	59,408,990	59,248,446	59,117,176
Diluted	59,408,990	61,492,446	60,827,224

See accompanying Notes to Consolidated Financial Statements

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

	Common Stock Shares	Common Stock Amount	Paid-in Capital	Accumulated Deficit	Total
Balance, December 31, 2006	59,003,284	$59	$54,517	$(30,156)	$24,420
Net income	-	-	-	3,510	3,510
Options and compensation expense	145,250	-	169	-	169
Commons stock issued for exercise of warrants	7,216	-	3	-	3
Balance, December 31, 2007	59,155,750	$59	$54,690	$(26,646)	$28,103
Net income	-	-	-	170	170
Options and compensation expense	-	-	213	-	213
Shares issued for compensation	30,000	-	18	-	18
Commons stock issued for exercise of warrants	164,911	-	72	-	72
Balance, December 31, 2008	59,350,661	$59	$54,993	$(26,476)	$28,576
Net income/loss	-	-	-	(2,018)	(2,018)
Options and compensation expense	-	-	174	-	174
Commons stock issued for exercise of options	410,000	1	110	-	111
Balance, December 31, 2009	59,760,661	$60	$55,277	$(28,494)	$26,843

See accompanying Notes to Consolidated Financial Statements

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

	Years Ended December 31,		
	2009	2008	2007
Operating activities			
Net income (loss)	$ (2,018)	$ 170	$ 3,510
Adjustments to reconcile net income to net cash			
Provided by operating activities			
Depletion, depreciation, and amortization	2,571	2,160	1,631
Accretion on asset retirement obligation	48	155	71
Ceiling test impairment	-	11,608	-
Loss on sale of vehicles/equipment	-	10	5
Compensation and services paid in stock options	174	231	116
Deferred tax benefit	(169)	(7,001)	(2,100)
Unrealized loss on derivatives	1,313	-	-
Changes in assets and liabilities			
Accounts receivable	(26)	(47)	(337)
Participant receivables	6	25	(37)
Other current assets	(10)	-	-
Inventory	(105)	(15)	90
Accounts payable	41	(203)	218
Accrued liabilities	(137)	67	332
Settlement on asset retirement obligations	-	(30)	(52)
Net cash provided by operating activities	1,688	7,130	3,447
Investing activities			
Additions to oil and gas properties	(1,020)	(11,965)	(5,191)
Drilling program portion of additional drilling	-	-	3,850
Proceeds from sale of oil and gas properties	142	-	-
Net additions to Methane Project	(184)	(2,707)	(1,650)
Net additions to pipeline facilities	(418)	(7)	-
Net additions to other property & equipment	-	(189)	(155)
Net cash (used in) investing activities	(1,480)	(14,868)	(3,146)
Financing activities			
Proceeds from exercise of options/warrants	111	72	56
Proceeds from borrowings	-	5,889	1,696
Loan fees	-	(69)	(77)
Repayment of borrowings	(142)	(136)	(119)
Net cash provided by (used in) financing activities	(31)	5,756	1,556
Net change in cash and change equivalents	177	(1,982)	1,857
Cash and cash equivalents, beginning of period	245	2,227	370
Cash and cash equivalents, end of period	$ 422	$ 245	$ 2,227
Supplemental cash flow information:			
Interest paid	$ 634	$ 447	$ 262
Supplemental non-cash investing and financing activities:			
Financed Company vehicles	$ 196	-	-

See accompanying Notes to Consolidated Financial Statements

1. 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.

2. 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 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 measurements. 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 preparation 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.

3. Related Party Transactions

On September 17, 2007, the Company entered into a drilling program with Hoactzin Partners, L.P. ("Hoactzin") for ten wells consisting of approximately three wildcat wells and seven developmental wells to be drilled on the Company's Kansas Properties (the "Ten Well Program"). Peter E. Salas, the Chairman of the Board of Directors of the Company, is the controlling person of Hoactzin. He is also the sole shareholder and controlling person of Dolphin Management, Inc. and the general partner of Dolphin Offshore Partners, L.P., which is the Company's largest shareholder. Carlos P. Salas, a director of the Company, has an interest in Hoactzin but is not a controlling person of Hoactzin. Under the terms of the Ten Well Program, Hoactzin was to pay the Company $0.4 million for each well in the Ten Well Program completed as a producing well and $0.25 million for each well drilled that was non-productive. The terms of the Ten Well Program also provide that Hoactzin will receive all the working interest in the ten wells in the Program, but will pay an initial fee to the Company of 25% of its working interest revenues net of operating expenses. This is referred to as a management fee but, as defined, is in the nature of a net profits interest. The fee paid to the Company by Hoactzin will increase to 85% of working interest revenues when and if net revenues received by Hoactzin reach an agreed payout point of approximately 1.35 times Hoactzin's purchase price (the "Payout Point") for its interest in the Ten Well Program.

In March 2008, the Company drilled and completed the tenth and final well in the Ten Well Program. Of the ten wells drilled, nine were completed as oil producers and are currently producing approximately 61 barrels per day in total. Hoactzin paid a total of $3.85 million (the "Purchase Price") for its interest in the Ten Well Program resulting in the Payout Point being determined as $5.2 million. The amount paid by Hoactzin for its interest in the Program wells exceeded the Company's actual drilling costs of approximately $2.8 million for the ten wells by more than $1 million.

Although production level of the Program wells will decline with time in accordance with expected decline curves for these types of wells, based on the drilling results of the wells in the Ten Well Program and the current price of oil, the Program wells would be expected to reach the Payout Point in approximately four years solely from the oil revenues from the wells. However, under the terms of the Company's agreement with Hoactzin, reaching the Payout Point may be accelerated by operation of a second agreement by which Hoactzin will apply 75% of the net proceeds it receives from a methane extraction project discussed below developed by the Company's wholly-owned subsidiary, Manufactured Methane Corporation ("MMC"), to the Payout Point. Those methane project proceeds when applied may result in the Payout Point being achieved sooner than the estimated four year period based solely upon revenues from the Program wells.

On September 17, 2007, Hoactzin, simultaneously with subscribing to participate in the Ten Well Program, pursuant to an additional agreement with the Company was conveyed a 75% net profits interest in the methane extraction project developed by MMC at the Carter Valley landfill owned and operated by Republic Services in Church Hill, Tennessee (the "Methane Project"). Revenues from the Project received by Hoactzin will be applied towards the determination of the Payout Point (as defined above) for the Ten Well Program. When the Payout Point is reached from either the revenues from the wells drilled in the Ten Well Program or the Methane Project or a combination thereof, Hoactzin's net profits interest in the Methane Project will decrease to a 7.5% net profits interest.

On September 17, 2007, the Company also entered into an additional agreement with Hoactzin providing that if the Program and the Methane Project interest in combination failed to return net revenues to Hoactzin equal to 25% of the Purchase Price it paid for its interest in the Ten Well Program by December 31, 2009, then Hoactzin would have 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. At the time the agreement was negotiated, the Company's forecast of the probable results of the projects indicated that there was little risk that the option to acquire preferred stock would ever arise, so the Company placed no significant value to the preferred stock option. By December 31, 2009 the amount of net revenues received by Hoactzin from the Ten Well Program has reduced the Company's obligation to Hoactzin for the amount of the funds it had advanced for the Purchase Price from \$3.85 million to \$1.3 million. 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. Hoactzin has a similar option each year after 2009 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 at date of the subsequent year's issuance if any. The Company, however, may in any year make a 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 no more than 19% 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, by definition the reduction of that 75% interest to a 7.5% net profits interest that was agreed to occur upon the receipt of 1.3547 of the Purchase Price by Hoactzin could not happen because the larger percentage interest then exchanged, no longer exists to be reduced. Accordingly, Hoactzin would retain no net profits interest in the Methane Project after a full exchange of Hoactzin's 75% net profits interest for preferred stock.

Under this exchange agreement, if no proceeds at all were received by Hoactzin through 2009 or in any year thereafter (i.e. a worst-case scenario already highly unlikely in view of the success of the Program), then Hoactzin would have an option to exchange 20% of its interest in the Methane Project in 2010 and each year thereafter for preferred stock with liquidation value of 100% of the Purchase Price (not 135%) convertible at the trailing average price before each year's issuance of the preferred stock. The maximum number of common shares into which all such preferred stock could be converted cannot be calculated given the formulaic determination of conversion price based on future stock price.

However, revenues from the Ten Well Program have resulted in 61% of the Purchase Price having already been reached. Accordingly, it is highly unlikely that any requirement to issue preferred stock will arise in 2010 or any succeeding years.

On December 18, 2007, the Company entered into a Management Agreement with Hoactzin. On that same date, the Company also entered into an agreement with Charles Patrick McInturff employing him as a Vice-President of the Company. Pursuant to the Management Agreement with Hoactzin, Mr. McInturff's duties while he is employed as Vice-President of the Company will include the management on behalf of Hoactzin of its working interest in certain oil and gas properties owned by Hoactzin and located in the onshore Texas Gulf Coast, and offshore Texas and offshore Louisiana. As consideration for the Company entering into the Management Agreement, Hoactzin has agreed that it will be responsible to reimburse the Company for the payment of one-half of Mr. McInturff's salary, as well as certain other benefits he receives during his employment by the Company. In further consideration for the Company's agreement to enter into the Management Agreement, Hoactzin has granted to the Company an option to participate in up to a 15% working interest on a dollar for dollar cost basis in any new drilling or work-over activities undertaken on Hoactzin's managed properties during the term of the Management Agreement. The term of the Management Agreement is the earlier of the date Hoactzin sells its interest in its managed properties or five years.

4. Deferred Conveyance/Prepaid Revenues

The Company has adopted a deferred conveyance/prepaid revenues presentation of the transactions between the Company and Hoactzin Partners, L.P. on September 17, 2007 to more clearly present the effects of the three-part transaction consisting of the Ten Well Program, the Methane Project and a contingent exchange option agreement.

To reflect the deferred conveyance, the Company has allocated $0.9 million of the $3.85 million Purchase Price paid by Hoactzin for its interest in the Ten Well Program to the Methane Project, based on a relative fair value calculation of the Methane Project's portion of the projected payout stream of the combined two projects as seen at the inception of the agreement, utilizing then current prices and anticipated time periods when the Methane Project would come on stream. The Ten Well Program at inception was $2.95 million and the prepaid revenues were $0.9 million.

The Company has established separate deferred conveyance and prepaid revenue accounts for the Ten Well Program and the Methane Project. Release of the deferred amounts to the Ten Well Program will be made as proceeds are actually distributed to Hoactzin. Release will be made on the respective proceeds only as to each project until either one or both satisfy the threshold amount that removes the contingent equity exchange option. The prepaid revenues will be released using the units of production method.

The reserve information for the parties' respective Ten Well Program interests as of December 31, 2009 is indicated in the table below. Reserve reports are obtained annually and estimates related to those reports are updated upon receipt of the report. These calculations were made using commodity prices based on the twelve month arithmetic average of the first day of the month price for the period January through December 2009 as required by SEC regulations. The table below reflects eventual pay as occurring through the realization of proceeds at prices used in the reserve report dated December 31, 2009 of approximately $53.81 per barrel.

Reserve Information for Ten Well Program Interest for the Year Ended December 31, 2009

	Barrels Attributable to Party's Interest MBbl	Future Cash Flows Attributable to Party's Interest (in thousands)	Present Value of Future Cash Flows Attributable to Party's Interest (in thousands)
Tengasco	29.5	$706.1	$431.6
Hoactzin Partners, L.P.	88.5	$2,118.3	$1,294.8

As of year-end 2009, the original invested amount of $3.85 million has been reduced to $1.3 million. This amount is the total of the deferred conveyance of $0.5 million and the prepaid revenue account of $0.85 million. Hoactzin's first right to convert its invested amount of $3.85 million into preferred stock is only exercisable to the extent Hoactzin's investment has not been reduced by 25% by the end of 2009. For each year after 2010 in which Hoactzin's then-unrecovered invested amount at the beginning of the year is not reduced 20% further by the end of that year, Hoactzin has a similar option. Consequently, Hoactzin is already precluded by these results from any possibility of exercising its contingent option under the exchange agreement to convert into preferred stock until the year ending December 31, 2011 at the earliest. All of the $2.5 million paid from the program has been from the Ten Well Program and the deferred conveyance account has been reduced from $3 million to $0.5 million.

As noted, in future periods, the Company anticipates that this Hoactzin investment will continue to be further reduced by sales of oil produced from the Ten Well Program, or methane produced from the Methane Project, or both. From inception of the project through December 31, 2010, the Company projects that the original $3.85 million Purchase Price will be reduced by 81% to $0.7 million. For the year ending December 31, 2011, the amount is projected to be reduced to zero. As a result, Hoactzin's contingent option to exchange for preferred stock would fully terminate without any further annual reduction tests. These projections are based upon expected production levels from the oil wells in the Ten Well Program and an estimated 400 Mcf/day production from the Methane Project using $40 oil prices and a $5 per Mcf gas sales price net of operating expenses. The projection will vary with the actual oil and gas prices, production volumes, and expenses experienced in 2010 and 2011. Based on these projections the Company considers that it is a remote contingency that any right of Hoactzin to elect to exchange its Methane Project interest for Company preferred stock will ever arise. However, in the event of a conversion of Hoactzin's Methane Project interest for Company preferred stock as set out in limited circumstances in the applicable agreement, and which the Company anticipates is highly unlikely, there would be a debit to the deferred conveyance liability and the prepaid revenue account for both the Ten Well Program and Methane Project because no contingent option would remain on such a conversion and the Company would simultaneously credit preferred stock in the converted amount.

In the event of the termination of the option to convert into preferred stock because the $3.85 million has been repaid from the Ten Well Program or Methane Project or both, the applicable oil and gas properties will be deemed to have been fully conveyed to Hoactzin and the Ten Well Program account, will be credited and the liability will be removed, as at this time the price received for the program will be fixed and determinable.

5. Oil and Gas Properties

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

	December 31,	
	2009	2008
Oil and gas properties, at cost	$ 24,182	$ 23,031
Unevaluated properties	109	1,243
Accumulated depreciation, depletion and amortization	(11,931)	(10,132)
Oil and gas properties, net	$ 12,360	$ 14,142

During the years ended December 31, 2009, 2008, and 2007, the Company recorded depletion expense of $1.8 million, $1.4 million and $0.8 million, respectively.

During 2009, the Company received $142,000 in proceeds for the disposal of the Deutsch, Howlier, Landers, and Pfeiffer properties. (See Note 23, Supplemental Oil and Gas Information, Standardized Measure of Discounted Net Cash Flows for information regarding the reserve value impact of these sales.)

6. Pipeline Facilities

In 1996, the Company began construction of a 65-mile pipeline connecting the Swan Creek development project to a gas purchaser and enabling the Company to develop gas transportation business opportunities in the future. Phase I, a 30-mile portion of the pipeline, was completed in 1998. Phase II of the pipeline, the remaining 35 miles, was completed in March 2001. .

The estimated useful life of the pipeline for depreciation purposes is 30 years. The Company recorded depreciation expense of $0.4 million, for the year ended December 31, 2009, and $0.5 million for the years ended December 31, 2008, and 2007. Gross costs were $16.8 million and $16.3 million and accumulated depreciation was $4.4 million and $4.0 million at December 31, 2009 and 2008, respectively.

7. Manufactured Methane Facility

The methane facility was placed in service on April 1, 2009, and is being depreciated over an estimated useful life of 13 years and 9 months. At December 31, 2009 gross costs were $4.5 million. Depreciation expense during 2009 was $0.1 million.

8. Other Property and Equipment

Other property and equipment consisted of the following: *(in thousands)*

December 31,	*Depreciable Life*	2009	2008
Machinery and equipment	5-7 yrs	$ 831	$ 831
Vehicles	2-5 yrs	561	556
Other	5 yrs	64	64
Total		1,456	1,451
Less accumulated depreciation		(1,150)	(1,166)
Other property and equipment-net		$ 306	$ 285

The Company uses the straight-line method of depreciation for other property and equipment

9. Long-Term Debt

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

December 31,	2009	2008
Note payable to a financial institution, with interest only payment until maturity. (See Note 19 Bank Debt)	$ 9,900	$ 9,900
Installment notes bearing interest at the rate of 5.5% to 8.25% per annum collateralized by vehicles with monthly payments including interest, insurance and maintenance of approximately $20,000	281	227
Total long-term debt	10,181	10,127
Current maturities	119	75
Long-term debt, less current maturities	$10,062	$10,052

10. Commitments and Contingencies

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

On March 1, 2010, the Company entered into a lease for office space in Knoxville, Tennessee. The term of the lease is 41 months (five of which are free) and expires on July 31, 2013. The payment on this lease is $7,284 per month.

Future non-cancellable commitments related to this lease are as follows (in thousands):

Year	
2010	$ 58
2011	73
2012	80
2013	51
	$262

Office rent expense for each of the three years ended December 31, 2009, 2008 and 2007 was $0.1 million.

11. Black Diamond Purchase

Effective as of July 1, 2008, the Company purchased from Black Diamond Oil, Inc. 80 barrels per day of oil producing properties and related leases in Rooks County, Kansas for $5.35 million. The Company also acquired producing oil wells and salt water disposal wells, equipment, and the underlying working interests in leases comprising what is known as the Riffe field that had been owned by Black Diamond for many years. The purchase price was paid primarily from borrowings under its credit facility with Sovereign Bank and from company cash on hand. Following the purchase, the Company has borrowed a total of $9.9 million under its credit facility.

12. Fair Value Measurements

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

Level 1 Inputs to the valuation methodology are unadjusted quoted prices for identical assets or liabilities in active markets. Level 2 Inputs to the valuation methodology include:

- Quoted prices for similar assets or liabilities in active markets; Quoted prices for identical or similar assets or liabilities in inactive markets;
- Inputs other than quoted prices that are observable for the asset or liability;
- Inputs that are derived principally from or corroborated by observable market data by correlation or other means.

If the asset or liability has a specified (contractual) term, the Level 2 input must be observable for substantially the full term of the asset or liability

Level 3 Inputs to the valuation methodology are unobservable and significant to the fair value measurement.

The assets or liabilities fair value measurement level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. Valuation techniques used need to maximize the use of observable inputs and minimize the use of unobservable inputs. Following is a description of the valuation methodologies used for assets measured at fair value.

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

The following table sets forth by level, within the fair value hierarchy, the Company's liabilities at fair value as of December 31, 2009. (in thousands)

	Level 1		**Level 2**		**Level 3**
Derivative liabilities	-		$1,313		-
Total liabilities at fair value	$ -		$1,313		$-

13. Derivatives

On July 28, 2009 the Company entered into a two-year agreement on crude oil pricing applicable to a specified number of barrels of oil that currently constitutes about two-thirds of the Company's daily production.

The agreement was effective beginning August 1, 2009. The "costless collar" agreement has a $60.00 per barrel floor an $81.50 per barrel cap on a volume of 9,500 barrels per month during the period from August 1, 2009 through December 31, 2010, and 7,375 barrels per month from January 1 through July 31, 2011. The prices referenced in this agreement are WTI NYMEX. While the agreement is based on WTI NYMEX prices, the Company receives a price based on Kansas Common plus bonus, which results in approximately $7 per barrel less than current WTI NYMEX prices. The average price per barrel received by the Company in the first quarter 2009 was $35.74, $52.52 for the second quarter 2009, $60.96 for the third quarter 2009 and $68.69 for the fourth quarter 2009.

Under a "costless collar" agreement, no payment would be made or received by the Company, as long as the settlement price is between the floor price and cap price ("within the collar"). However, if the settlement price is above the cap, the Company would be required to pay the counterparty an amount equal to the excess of the settlement price over the cap times the monthly volumes hedged. Also, if the settlement price is below the floor, the counterparty would be required to pay the Company the deficit of the settlement price below the floor times the monthly volumes hedged.

This agreement is primarily intended to help maintain and stabilize cash flow from operations if lower oil prices return, while providing at least some upside if prices increase above the cap. If lower oil prices return, this agreement may help to maintain the Company's production levels of crude oil by enabling the company to perform some ongoing polymer or other workover treatments on then existing producing wells in Kansas.

As of December 31, 2009, our open forward positions on our outstanding "costless collar" agreements, all of which are with Macquarie Bank Limited ("Macquarie"), were as follows:

Period	**Monthly Volume**	**Total Volume**	**Floor/Cap NYMEX**	**Fair Value at December 31, 2009 (in thousands)**
	Oil (Bbls)	**Oil (Bbls)**	**$ per Bbl**	
1st Qtr 2010	9,500	28,500	$60.00-$81.50	$ (78)
2nd Qtr 2010	9,500	28,500	$60.00-$81.50	$ (174)
3rd Qtr 2010	9,500	28,500	$60.00-$81.50	$ (228)
4th Qtr 2010	9,500	28,500	$60.00-$81.50	$ (268)
1st Qtr 2011	7,375	22,125	$60.00-$81.50	$ (231)
2nd Qtr 2011	7,375	22,125	$60.00-$81.50	$ (248)
3rd Qtr 2011	7,375	7,375	$60.00-$81.50	$ (86)
				$ (1,313)
			Current Liability	$ (748)
			Non-current Liability	$ (565)

The Fair Value amounts noted in the above table are based on valuations provided by Macquarie. Management has engaged Risked Revenue Energy Associates to perform an independent valuation which confirmed the amounts provided by Macquarie. The Company records changes in the unrealized derivative asset or liability as an unrealized gain or loss in the Consolidated Statements of Operations.

Through December 31, 2009, no settlement payment has been required under the agreement as WTI NYMEX prices through that date remained within the collar.

14. Asset Retirement Obligation

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.

The following is a roll-forward of activity impacting the asset retirement obligation for the years ended December 31, 2008 and 2009: *(in thousands):*

Balance December 31, 2007	$ 531
Accretion expense	155
Liabilities settled	(30)
Balance December 31, 2008	$ 656
Accretion expense	48
Liabilities incurred	2
Revisions in estimated liabilities	(256)
Balance December 31, 2009	$ 450

The liabilities incurred relate to the Albers #2 SWD. The revisions in estimated liabilities resulted primarily from reducing the estimated plugging and abandonment costs for the Kansas properties from $10,000 per well to $5,000 per well.

15. Stock Options

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

Stock option activity in 2009, 2008, and 2007 is summarized below:

	2009		2008		2007	
	Shares	**Weighted Average Exercise Price**	**Shares**	**Weighted Average Exercise Price**	**Shares**	**Weighted Average Exercise Price**
Outstanding, beginning of year	2,931,000	$0.38	2,441,000	$0.30	2,596,000	$0.31
Granted	500,000	$0.54	500,000	$0.74	-	-
Exercised	(410,000)	$0.27	(10,000)	$0.27	(126,000)	$0.42
Expired/cancelled	-	-	-	-	(29,000)	$0.64
Outstanding end of year	3,021,000	$0.42	2,931,000	$0.38	2,441,000	$0.30

The following table summarizes information about stock options outstanding and exercisable at December 31, 2009:

Weighted Average Exercise Price	**Options Outstanding (shares)**	**Weighted Average Remaining Contractual Life (years)**	**Options Exercisable (shares)**
$0.27	1,831,000	0.3	1,831,000
$0.58	110,000	1.1	110,000
$0.81	80,000	2.0	80,000
$0.57	400,000	3.1	160,000
$1.44	100,000	3.4	100,000
$0.70	100,000	4.0	100,000
$0.50	400,000	5.7	-
	3,021,000		2,381,000

During 2009, the Company issued options to purchase 25,000 shares at $0.70 per share to each of the non-executive directors. These options vested upon grant date (January 8, 2009) and expire January 7, 2014. In addition, the Company issued options to purchase 400,000 shares at $0.50 per share to Michael J. Rugen, Chief Financial Officer. The options were issued on September 28, 2009. The options will vest over a five year period and will expire on September 27, 2015. Also during 2009, Mark A. Ruth, former Chief Financial Officer, exercised 400,000 options at $0.27 per share.

The weighted average fair value per share of options granted in 2008 and 2009 range from $0.39 to $1.06, calculated using the Black Scholes option pricing model.

Compensation expense related to stock options was $0.2 million in 2009 and 2008 and $0.1 million in 2007. At December 31, 2009, there was $0.2 million of total unrecognized compensation costs related to unvested options that is expected to be recognized over a weighted average period of approximately 2.1 years.

The fair value of stock options used to compute share based compensation is the estimated present value at grant date using the Black Scholes option pricing model with the following weighted average assumptions for 2008 and 2009: expected volatility of 100%, a risk free interest rate of 3.67% and an expected option life remaining from 0.3 to 5.7 years.

On February 8, 2010, the Company issued options to purchase 25,000 common shares at $0.43 per share to each of the non-executive directors. These options vested upon grant date and will expire February 7, 2015.

16. Income Taxes

The Company had no taxable income for the year ended December 31, 2009, but had taxable income for the years ended December 31, 2008 and 2007.

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

	December 31,		
	2009	**2008**	**2007**
Statutory rate	34%	34%	34%
Tax (benefit)/ expense at statutory rate	$(744)	$(2,323)	$ 480
State income tax expense	142	197	140
Impairment write-down not deductible for tax purposes	-	3,947	-
Unrealized loss on derivatives not deductible for tax purposes	446	-	-
Excess tax depreciation	(75)	(65)	(85)
Other	62	(132)	3
Utilization of NOL carry-forward	-	(1,624)	(538)
Net Change in deferred tax asset valuation allowance	(169)	(7,001)	(2,100)
Total income tax provision (benefit)	$(169)	$(7,001)	$(2,100)

Management has evaluated the positions taken in connection with the tax provisions and tax compliance for the years included in these financial statements as required by ASC 740. The Company does not believe that any of its positions it has taken will not prevail on a more likely than not basis. As such no disclosure of such positions was deemed necessary. Management continuously estimates its ability to recognize a deferred tax asset related to prior period net operating loss carry forwards based on its anticipation of the likely timing and adequacy of future net income. The Company has had recurring taxable income for its last three fiscal years. As of January 1, 2009, the Company had available approximately $15.5 million of net operating loss carry forwards to offset future taxable income.

During the year ended December 31, 2009, Management, using the “more likely than not” criteria for recognition, elected to recognize a deferred tax asset of $0.2 million. The recognition of the deferred tax asset in 2009 relates to net operating loss carryforwards and will provide a better matching of income tax expense with taxable income in future periods. The current provision reflects the recognition of $0.2 million current income tax benefit (fully offset by the current provision related to 2009 taxable income) and $9.1 million.

At December 31, 2009, the deferred tax asset balance is $9.3 million. At December 31, 2008, the deferred tax asset balance was $9.1 million. The Company recorded an additional $3.9 million deferred tax benefit as a result of the $11.6 million ceiling test write-down. The recognition of the deferred tax asset will provide a better matching of income tax expense with taxable income in future periods.

As of December 31, 2009, the Company had net operating loss carry forwards of approximately $15.5 million which will expire between 2011 and 2023 if not utilized. Our open tax years include all returns filed for 2006 and later.

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

	Year Ended December 31,		
	2009	**2008**	**2007**
Deferred tax assets:			
Net operating loss carry-forward	$ 5,982	$ 6,015	$ 7,314
Capital loss carry-forward	263	263	263
Excess of tax over book basis of oil and gas properties	4,334	3,947	-
Total deferred tax assets	$10,579	$10,225	$ 7,577
Deferred tax liability			
Basis difference in pipeline	$ 1,309	$ 1,124	$ 1,209
Total deferred liability	1,309	1,124	1,209
Total net deferred taxes	$ 9,270	$ 9,101	$ 6,368
Valuation allowance	-	-	(4,268)
Net deferred tax asset	$ 9,270	$ 9,101	$ 2,100

17. Supplemental Cash Flow Information

The Company paid approximately $0.6 million, $0.4 million, and $0.3 million, for interest in 2009, 2008, and 2007 respectively. No interest was capitalized in 2009, 2008, or 2007.

18. Litigation Settlement

On May 10, 2004 the Court entered its final order approving the fairness of the settlement to the class, dismissing the action pursuant to a Settlement Stipulation, and fully releasing the claims of the class members in *Paul Miller v. M. E. Ratliff and Tengasco, Inc*. No. 3:02-CV-644 in the Unites States District Court for the Eastern District of Tennessee, Knoxville, Tennessee. This action sought certification of a class action to recover on behalf of a class of all persons who purchased shares of the Company's common stock between August 1, 2001 and April 23, 2002, unspecified damages allegedly caused by violations of the federal securities laws. In January, 2004 all parties reached a settlement subject to court approval. The Court entered its order approving the settlement on May 10, 2004. Under the settlement, the Company paid into a settlement fund the amount of $37,500 to include all costs of administration and contribute 150,000 warrants to purchase a share of the Company's common stock for a period of three years from date of issue at $1 per share subject to adjustments. The Rights Offering adjusted this price to $0.45 per share. These warrants expired on September 12, 2008.

19. Bank Debt

On December 17, 2007, Citibank assigned the Company's revolving credit facility with Citibank to Sovereign Bank of Dallas, Texas ("Sovereign") 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 Project assets. The Company's initial borrowing base with Sovereign was set at $7.0 million, an increase from its borrowing base of $3.3 million with Citibank prior to the assignment.

On June 2, 2008, the Company entered into an amendment to its credit facility with Sovereign whereby the Company's borrowing base was raised by Sovereign 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 then 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.

On 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 is not a cash payment obligation of the Company but has the effect of reducing the Company's available borrowing base in monthly increments of $0.15 million so that by June 2009 the Company's available borrowing base under the Sovereign facility was to be reduced by $0.75 million from $11.0 million to $10.25 million.

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. The Company's borrowing base was increased on the completion of the regular semiannual borrowing base review by Sovereign. The $11.0 million borrowing base is again made subject to a monthly available-credit reduction of $0.15 million per month beginning August 5, 2009, so that by the time of the next regular borrowing base review in six months, the borrowing base will again be $10.25 million.

As of September 30, 2009, the Company was out of compliance on the Leverage Ratio and Interest Coverage Ratio covenants under the credit facility. The Company was in compliance with the remaining financial covenants 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. This amendment increased the borrowing base from $10.25 million to $11.0 million as a result of the 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. The amendment also 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.

20. 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 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 will 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 between the years 2022 and 2029. Gas production will continue in commercial quantities up to 15 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 1 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. 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. However, as of December 31, 2009 neither of these actions has been taken by EPA, despite the existence of EPA's own established agency initiative, the Landfill Methane Outreach Program, which is intended to encourage beneficial use of the methane component of raw landfill gas. Because approval was not received, MMC was forced to seek alternative markets for the methane gas stream.

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.

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.

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 is 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 Mcfd of methane from the Carter Valley landfill at current raw gas volumes. However, daily production during September and October 2009 at MMC's facility was intermittent due to a combination of temporary factors. Average daily production for September and October 2009 was 248 Mcfd on the twenty days the plant was in production. In November 2009, MMC's average daily gas production on producing days was 288 Mcfd of sales methane and in December 2009, this amount was 293 Mcfd of sales methane.

On September 17, 2007, Hoactzin, simultaneously with subscribing to participate in the Ten Well Program (the "Program"), pursuant to a separate agreement with the Company was conveyed a 75% net profits interest in the Methane Project. The revenues from the Methane Project received by Hoactzin are to be applied towards the determination of the Payout Point (as defined above) for the Ten Well Program. When the Payout Point is reached from either the revenues from the wells drilled in the Program or the Methane Project or a combination thereof, Hoactzin's net profits interest in the Methane Project will decrease to a 7.5% net profits interest. The Company believes that the application of revenues from the Methane Project to reach the Payout Point could accelerate reaching the Payout Point. As stated above, the Purchase Price paid by Hoactzin for its interest in the Program exceeded the Company's anticipated and actual costs of drilling the ten wells in the Program. Those excess funds provided by Hoactzin were used to pay for approximately $1 million of equipment required for the Methane Project, or about 22% of the Project's capital costs. The availability of the funds provided by Hoactzin eliminated the need for the Company to borrow those funds, to have to pay interest to any lending institution making such loans or to dedicate Company revenues or revenues from the Methane Project to pay such debt service. Accordingly, the grant of a 7.5% interest in the Methane Project to Hoactzin was negotiated by the Company as a favorable element to the Company of the overall transaction.

21. Restricted Cash

As security required by Tennessee oil and gas regulations, the Company placed $120,500 in a Certificate of Deposit to cover future asset retirement obligations for the Company's Tennessee wells.

22. Quarterly Data and Share Information (unaudited)

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

Fiscal Year Ended 2009	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr
Revenues	$ 1,900	$ 2,355	$ 2,585	$ 2,891
Net loss	(402)	(81)	(449)	(1,086)
Net loss attributable to common shareholders	(402)	(81)	(449)	(1,086)
Loss per common share	$ (0.01)	$ (0.00)	$ (0.01)	$ (0.02)

Fiscal Year Ended 2008	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr
Revenues	$ 3,306	$ 4,634	$ 5,067	$ 2,594
Net income (loss)	5,812	1,422	1,563	(8,627)
Net income (loss) attributable to common shareholders	5,812	1,422	1,563	(8,627)
Income (loss) per common share	$ 0.10	$ 0.02	$ 0.03	$ (0.14)

During the first quarter of 2008, the Company recorded a $5.2 million deferred tax asset. During the fourth quarter of 2008 the Company recorded a $11.6 million ceiling test write-down.

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.